Appendix E

Lakeland Holding Ltd. Strategic Plan (2023-2027)

LAKELAND HOLDING LTD.

Strategic Plan 2023-2027

PREFACE

Lakeland Holding Ltd. is a leader in green, smart energy and broadband and is a company known for its solid safety record, reliable service and exceptional customer service. With an eye to the future, Lakeland Holding Ltd. has developed a new Intelligent Corporate Strategic Plan that will see the company expand the value it offers to shareholders, customers and the communities it serves.

Lakeland Holding Ltd. will rely on this Strategic Plan to position the company as a catalyst for transformative change and ensure Lakeland remains at the helm as a leader in a dynamic and smart broadband and energy world.

Land Acknowledgement

Lakeland respectfully acknowledges that we work and live on lands that are the traditional territories of Indigenous Communities. We offer gratitude to Indigenous peoples for their care for, and teachings about, our earth and our relations.

Message from the Chair & CEO

On behalf of Lakeland Holding Ltd., we are pleased to present the updated Lakeland Holding Ltd. Strategic Plan. This plan includes goals and strategies to expand our partnerships and collaborations and leverage technology in ways that will position the company, our shareholders, our customers, and our communities to thrive.

The last three years have been defined by seismic change and looking forward, we anticipate that this accelerated pace of change will only continue. Lakeland must be anticipatory and fully prepared to exceed expectations. We recognize the critical role we play in providing essential services and moreover that we will have to work harder to meet the needs of our shareholders, customers and our communities. While we will continue to provide safe, reliable and accessible services and products, wherever we operate, we will ensure that we are providing the safest, most reliable and highest level of quality and service. We will continue to evolve as a leading innovator in the management and operations of electricity transmission and telecommunication networks and we will remain committed to being the driving force and backbone for universal connectivity and smart operations.

We are exceptionally proud of the many accomplishments that have been realized in Lakeland's 23-year history. We are, and will remain, a company of firsts. In the next four years and beyond, we will focus our efforts on maximizing the impact we have on our shareholders, customers and communities, We will ensure we are a trusted partner of choice and that we remain steadfast in our commitment to continually improve operational efficiencies and effectiveness. We will work to maintain the trust and confidence that has been placed in us as solid corporate citizens and we will be driven to improve the quality of life in the communities we serve.

Chris Litschko
CEO

Roger Alexander
Chair, Board of Directors

Introduction

This 2023-2027 Strategic Plan provides an overview of Lakeland Holding Ltd.'s strategic priorities and directions for the next four years. It is designed to inform our shareholders, partners, customers and community members about the most critical trends shaping our business environment, and how the company intends to respond to them.

This Strategic Plan builds on the solid record of success that has been realized by Lakeland Holding Ltd. over its 23 years in business. Signature achievements since last strategic plan 3 years ago have included 7 years of excellent safety record, the purchase of the Wasdell Falls Generating Station, hiring of 30 team members, $35M in capital investments, record number of fibre connections, the approval of a 25-year Chute Blanche contract, and notably, creation of the first microgrid for which Lakeland received the Electricity Distributors Association 2022 Innovation Excellence Award for the SPEEDIER and DEMOCRASI projects. Lakeland has improved Hydro One reliability at the Bracebridge Transformer Station, as well as undertaken the implementation of a digital CHATBOT platform to improve customer experience and service.

Building on this record of achievement, Lakeland is looking to the future and has identified strategic priorities that will continue to place the company at the forefront of smart energy innovation and service. Continuing to put safety and system reliability first, Lakeland intends to expand its service offerings through partnership and collaboration while ensuring its commitment to a gold standard of customer service remains top of mind. Lakeland will continue to lead as an innovator and partner in a smart energy future.

Lakeland Holding Ltd…reliable service…safety first…future focused.

The Vision

VISION STATEMENT

BE THE LEADER IN SUSTAINABLE SOLUTIONS AND CATALYST FOR IMPROVING THE LIVES OF OUR CUSTOMERS AND COMMUNITIES WE SERVE.

The Mission

MISSION STATEMENT

LEVERAGING OUR TEAM, WE ARE DEDICATED TO GROWING RESPONSIBLY, SERVING OUR SHAREHOLDERS, CUSTOMERS AND COMMUNITIES WITH SAFE, RELIABLE, AND QUALITY SUSTAINABLE SOLUTIONS.

Corporate Values

RECOMMENDATIONS FOR THE CORPORATE VALUES STATEMENT

SAFETY: WE ARE DEDICATED TO THE SAFETY OF OUR EMPLOYEES AND COMMUNITIES.

ENVIRONMENTAL STEWARDSHIP: WE ARE CONCERNED FOR THE ENVIORNMENT IN EVERYTHING WE DO. WE ARE COMMITTED TO PROTECTING AND NOURISHING THE ENVIRONMENT BY DOING BETTER FOR OUR PLANET WHILE WE GROW.

RELIABILITY: WE PROVIDE DEPENDABLE, CONSISTENT AND RELIABLE SERVICE.

ACCOUNTABILITY: WE ARE SERIOUS AND RESPONSIBLE FOR OUR ACTIONS AND ACCOUNTABLE TO THOSE WE SERVE.

PARTNERSHIPS: WE DRAW ON ONE ANOTHER AND OUR PARTNERS TO ACHIEVE SUCCESS.

PROFESSIONALISM: WE ARE DEDICATED TO EXCELLENCE IN MANAGEMENT AND SERVICE DELIVERY. WE ARE INCLUSIVE AND ARE COMMITTED TO PROVIDING EQUITABLE SERVICES AND TREATING ALL WITH RESPECT.

CONTINUOUS IMPROVEMENT: WE CONSTANTLY SEEK NEW IDEAS, ARE FUTURE FOCUSED AND RESULTS ORIENTED. WE ARE EFFICIENT, EFFECTIVE, INNOVATIVE AND WE OFFER VALUE-ADDED.

RELATIONSHIP BUILDING & RECONCILIATION: WE ARE COMMITTED TO RELATIONSHIP BUILDING AND RECONCILIATION. WE ARE DRIVEN BY TRUST AND INTEGRITY AND WE VALUE THE KNOWLEDGE AND EXPERIENCE OF ALL.

Corporate Goals

Goals:

At the very core of our Strategic Plan is the commitment to provide safe, reliable and smart broadband and energy solutions. The critical foundation upon which our key goals depend is Organizational Excellence. We will continue to be known as an employer of excellence.

Strategic Goals, Objectives & Actions

The Foundation of the Strategic Plan: Lakeland Holding Ltd.: An Exceptional Organizational

Objectives:

- A safe and healthy workplace
- An engaged, prepared and diverse workforce
- Efficient and effective operations

Objectives	Strategic Actions
A Safe & Healthy Workplace	✦ Continue to place priority emphasis on the health and safety of our employees and our communities
An Engaged, Prepared & Diverse Workforce	✦ Develop and implement a Human Resource Strategy (Talent Management Strategy) that is directly tied to the Strategic Plan (recruitment, retention, succession safety, training) ✦ Develop and implement an Employee Engagement Strategy ✦ Continually review-improve-update Diversity, Equity and Inclusion policies and procedures ✦ Identify opportunities to enhance corporate social responsibility, rewards and recognition, employee wellness, and professional development ✦ Undertake an organizational review to determine whether a Vice President can bring innovative products and services to market
Efficient & Effective Operations	✦ Implement new HRIS system to streamline processes and procedures ✦ Implement new Enterprise Resource Planning software (ERP) to reduce duplications, triplication, etc. associated with manual input ✦ Continue to leverage leading technology and assets to advance digital transformation and modernization to enable sustainable business practices (generative AI, etc.), improve organizational agility, increase automation and enable employees to make faster and more informed decisions ✦ Continue to identify opportunities to increase operational reliability ✦ Identify opportunities to improve reporting and transparency

Goal 1: Maximize Shareholder Value

Lakeland Holding Ltd. Commitment Statement:

- We will make smart and strategic organizational decisions that maximize the anticipated return and expected value of our shareholders.
- We will deliver superior performance and, as Board Members, Senior Executives and Senior Managers, will bear the risk of ownership just as our shareholders do.
- We will provide investors with value-relevant information and focus on value-creating growth.
- We will create sustainable growth in our business and in our earnings.

Objectives:

- Maintain and enhance profitability
- Manage Costs
- Increase Revenue
- Maintain Reliability & Grow the Company

Objectives	Strategic Actions
Maintain and Enhance Profitability	- Continue to demonstrate solid financial performance - Amplify opportunities to grow Lakeland's social license to operate
Manage Costs & Increase Revenue	- Identify opportunities for sustainable growth across all business lines and through earnings - Identify opportunities to diversify revenue sources - Identify opportunities to reduce costs
Maintain Reliability & Grow the Company	- Focus on organic growth at Lakeland Power and improve system reliability through the: - Installation of smart switches (smart grid) with software to reduce outage time and enhance outage reaction - Installation of new municipal station in Bracebridge to take advantage of Hydro One transformer station reliability

Goal 2: Enhance Community Prosperity & Quality of Life

Lakeland Holding Ltd. Commitment Statement:

- We will be a force for good across the communities we serve.
- We will provide jobs and local opportunity, offer goods and services, and bring innovation to the marketplace.
- We will provide services that are inclusive and accessible.

Objectives:

- An engaged community
- Environmental sustainability and stewardship
- A Well-Known & Trusted Organization

Objectives	Strategic Actions
An Engaged Community	Undertake a comprehensive stakeholder/influencer analysis (employees, customers, suppliers, community leaders and community members) to better understand requirements, perceptions and areas of opportunity Identify opportunities to increase community, stakeholder and rights holder engagement
Commitment to Environmental Sustainability & Stewardship	Continue to commit to the principles of environmental stewardship. Identify opportunities to demonstrate environmental stewardship and sustainability in Lakeland operations, policies and practices
A Well-Known & Trusted Organization	Continue to invest at the community level and identify opportunities to maximize impact and align with Lakeland's role in the communities it serves

Goal 3: Grow & Evolve Through Innovation & Partnerships

Lakeland Holding Ltd. Commitment Statement:

- We will continue to grow and evolve the company through innovation and partnerships.
- We will make innovation a top priority and seek opportunities to gain competitive advantage and enhance value.
- We will promote a culture of innovation within the workplace and we will explore opportunities to expand our product and service lines to meet the demands of a larger audience.
- We will also track our performance, measure improvements and focus on achieving our full potential.
- We will think of innovation as a critical aspect of our business that must be managed and executed methodically.
- We will work collaboratively to strengthen our relationships and advance reconciliation.

Objectives:

- Strengthen existing and build new partnerships
- Learn from Others

Objectives	Strategic Actions
Strengthen Existing & Build New Partnerships	- Identify opportunities to strengthen existing and forge new partnerships with others who bring complementary competencies and resources - Identify opportunities to build the relationship with Indigenous partners and communities and to support their energy needs (i.e., Community Net Metering once available) - Identify opportunities to partner with partners including municipalities beyond the current service area, universities, schools and hospitals -
Learn from Others	- Explore good practices with a view to replicating existing models that have proven to be of value

Goal 4: Amplify Exceptional Customer Service

Lakeland Holding Ltd. Commitment Statement:

- We will stand out from our competitors by focusing on the customer experience.
- We will be a customer-centric organization, adopting a ‘painless, personalized, productive and proactive approach.

Objectives:

- Improved Customer Experience
- Enhanced Visibility

Objectives	Strategic Actions
Improved Customer Experience	- Advance a ‘whole company’ customer experience by continuing to commit to a customer-centric culture - Identify opportunities to invest in leading-edge services, technologies and processes to enhance the customer experience, with a view to improving choice and convenience - Identify opportunities to work collaboratively with customers to develop services and products that empower them to manage their energy use and associated costs - Identify opportunities to improve customer service at Lakeland Power - Advance Community Net Metering once available

Top Five Strategic Priorities

Over the next four years, Lakeland Holding Ltd. will focus its efforts in the following key strategic priority areas:

Business Line	**Focus**	**Specific Details**
LAKELAND HOLDING LTD.	Implement HR Strategy	Develop and implement a Human Resource Strategy (Talent Management Strategy) that is directly tied to the Strategic Plan

		(recruitment, retention, succession safety, training)

Lakeland Holding Ltd. will continue to emphasize its commitment to operational efficiency and effectiveness, improved reliability and enhanced customer service.

Business Line	**Focus**	**Specific Details**
LAKELAND HOLDING LTD.	Continued efficient operations	New Human Resource Information System to streamline processes and procedures. Implement new Enterprise Resource Planning software (ERP) to reduce duplication, triplication, etc. to manual input. Utilize BOTS, etc. where practical.
LAKELAND POWER	Improve Reliability	Install smart switches (smart grid) with software to increase reaction to outage and decrease outage time. Improve outage management system. Install new municipal station in Bracebridge – take advantage of Hydro One transformer station reliability.
	Improve Customer Service	OEB satisfaction survey result of 75% did not meet improvement goal of 77%.

Appendix F

Needs Assessment Report – South Georgian Bay - Muskoka

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

South Georgian Bay - Muskoka

Date: April 30, 2020

Prepared by: South Georgian Bay - Muskoka Region Study Team

Transmission & Distribution

Newmarket-Tay Power Distribution Ltd.

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the South Georgian Bay - Muskoka 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 Study Team for this region.

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

Executive Summary

REGION	South Georgian Bay (SGB) – Muskoka (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")
START DATE: January 30, 2020	**END DATE:** April 30, 2020

1. INTRODUCTION

The first cycle of the Regional Planning process for the South Georgian Bay (SGB) - Muskoka Region was completed in July 2016 with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

This is the second cycle of regional planning starting with a Needs Assessment ("NA"). The purpose of this NA is a) to identify any new needs and/or to reaffirm needs identified in the previous SGB-Muskoka Regional Planning cycle and b) recommend which need may be a) met more directly by distributors or other customers and their respective transmitter b) 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. In light of these timelines, the 2nd Regional Planning cycle was triggered for SGB-Muskoka Region.

3. SCOPE OF NEEDS ASSESSMENT

This assessment's primary objective is to identify the electrical infrastructure needs over the study period, develop options and recommend which needs require further regional coordination.

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous RIP; and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs in the region: and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs in the region.
- Identify needs that will require further coordination at the regional level and those which can be met more directly by distributors and other customers as their respective transmitter.

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), IRRP and RIP, based on updated information available at that time.

As per the PPWG Regional Planning Report to the Board (May 2013), the planning horizons of regional facilities are typically considered over 1-20 years; however, in most situations focus is over the 1 – 10-year timeframe.

4. INPUTS/DATA

The Study Team 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 assets/facilities approaching end-of-life (“EOL”).

5. ASSESSMENT METHODOLOGY

The assessment methodology includes review of planning information such as load forecast, conservation and demand management (“CDM”) forecast and available distributed generation (“DG”) information, any system reliability and operation issues, and major high voltage equipment identified to be at or near the end of their life.

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 high voltage equipment reaching the end of its life.

6. NEEDS

I. Needs Identified from Previous Cycle – Implementation Plan Update

i. Barrie TS transformer supply capacity will be exceeded, and consequently result in thermal violation of the radial supply circuits (E3B/E4B). The majority of equipment at Barrie TS as well as the Essa TS 115kV yard have also been assessed at being end of life and in need of replacement due to asset condition. This resulted in creation of the Barrie Area Transmission Reinforcement (BATU) project to address these needs. This investment in presently underway with an in-service date scheduled for 2022.

ii. 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 asset condition. Hydro One will be installing new 230/44kV 83MVA transformers to address both end of life and supply capacity needs. The In-service is scheduled for 2024.

iii. Loss of M6E and M7E will result in violation of ORTAC load restoration criteria based on the peak load forecast. To adhere to the criteria, Hydro One will be installing 230kV motorized disconnect switches on the M6E and M7E circuits (at Orillia TS) to improve load restoration time. The In-service is scheduled for 2021.

iv. Minden TS – Replace 230/44kV 42MVA (T1/T2) transformers with new 230/44kV 83MVA units. These transformers have been assessed at being end of life and in need of replacement due to asset condition. The In-service scheduled is for 2021.

v. Orangeville TS – Replace and upgrade existing 230/44kV 83MVA transformers (T3/T4) with new 125MVA units. Replace and upgrade existing non standard 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. These transformers and associated low voltage equipment has been assessed at being end of life and in need of replacement due to asset condition. This is presently underway with an In-Service scheduled for 2023.

II. Newly Identified Needs in the region

i. Waubaushene TS - This station will exceed its normal supply capacity at the end of 2020 based on the summer demand forecast. An immediate solution is required to address the summer loading concern and shall be coordinated with a permanent solution to address long term supply capacity needs. As well, the transformers are expected to be at the end of the study period and require replacement by 2030.

ii. Everett TS – Load growth at this station is restricted due to a limiting component within the low votage yard. This will be need to be corrected by 2026 to allow load to continue growing as per demand forecast.

iii. Barrie TS - This station will exceed its normal summer and winter supply capacity in 2024 and 2026 respectively, based on the existing 115/44kV transformers installed. The Barrie Area Transmission Project (BATU) will be completed in 2022, and help to address existing capacity, and end of life issues that have been identified in the first RP cycle. Although supply capacity appears to be available post-BATU, Hydro One Distribution and its embedded LDC (InnPower) will be constrained at the 44kV feeder supply level in 2025. A plan is required to address the supply capacity need from InnPower beyond what Barrie TS can provide.

iv. Parry Sound TS - This station will exceed supply in 2020 based on the winter demand forecast. Hydro One will be upgrading the transformers with two new 230/44kV 83MVA units in 2024. A solution is required to address the immediate station capacity need.

v. Sections of M6E/M7E are at end of life and in need of replacement – Refurbish 25km of 230kV transmission line from Orillia TS x Coopers Falls JCT – In-Service 2024

Sections of E8V / E9V are at end of life and in need of replacement – Refurbish 56km of 230kV transmission line from Orangeville TS x Essa JCT – In-Service 2027

Sections of D1M / D2M are at end of life and in need of replacement – Refurbish 62km of 230kV transmission line from Minden TS x Otter Creek JCT - In-Service 2028

vi. M6E/M7E (Essa TS x Midhurst TS) thermal overloading - With four Des Joachims GS units out of service the subsequent loss of either M6E or M7E will result in the companion circuit to exceed its LTE (Long

Term Emergency) rating on the line section from Essa TS x Midhurst TS. This overload occurs as early as 2023.

7. RECOMMENDATIONS

i. Waubaushene TS – Hydro One will coordinate with the connected LDC and their embedded customers (as needed) to address the immediate supply capacity constraints that may appear within the next year. Permanent solution(s) will require further regional coordination to verify if non-wires options would be beneficial. Further regional coordination is required.

ii. Everett TS – Full utilization of the station transformer capacity is restricted by a series limiting component. A CT ratio setting on the low voltage bushing of the transformer breaker can be modified to allow full transformer LTR capability. Hydro One will initiate a project directly in collaboration with the LDCs as soon as practical. Further regional coordination is not required.

iii. Barrie TS – The Barrie Area Transmission Upgrade (BATU) project is presently underway with a planned in service of 2022. No further coordination is required for the BATU project.

The working group will continue to develop supply capacity solution(s) for Innisfil area load growth. Further regional coordination is required.

iv. Parry Sound TS – The station transformer upgrade is presently underway and scheduled to be in service in 2024. Hydro One will try to expedite the replacement as quickly as possible and manage overloading risk to the existing transformers. No further regional coordination is required.

v. M6E/M7E (Essa x Midhurst) Overloading – Further regional coordination is required.

vi. Replacement of end of life assets (section 8.1 e.f.g) require further regional coordination.

TABLE OF CONTENTS

2 Introduction 8
3 Regional Issue/Trigger 9
4 Scope of Needs Assessment 9
5 Regional Description and Connection Configuration 9
6 Inputs and Data 13
7 Assessment Methodology 13
8 Needs 14
9 Conclusion and Recommendations 19
Appendix A: Weather Adjusted Non-Coincident Summer Forecast 20
Appendix A: Weather Adjusted Non-Coincident Winter Forecast 23
Appendix B: Lists of Step-Down Transformer Stations 26
Appendix C: Lists of Transmission Circuits 27
Appendix D: Lists of LDCs in the SGB-Muskoka Region 28
Appendix E: Acronyms 29

List of Tables and Figures

Table 1: SGB-Muskoka Region Study Team Participants 8
Table 2: Needs Identified in the Previous Regional Planning Cycle 14

Figure 1: Geographical Area of SGB-Muskoka Region with Electrical Layout 10
Figure 2: Single Line Diagram of South Georgian Bay - Muskoka Region 12

2 INTRODUCTION

The first cycle of the Regional Planning process for the South Georgian Bay - Muskoka Region was completed in July 2016 with the publication of the Regional Infrastructure Plan ("RIP"). The RIP provided a description of needs and recommendations of preferred wires plans to address near- and medium-term needs.

The purpose of this Needs Assessment ("NA") is to identify new needs and to reconfirm needs identified in the previous SGB-Muskoka regional planning cycle. Since the previous regional planning cycle, some new needs in the region have been identified.

This report was prepared by the South Georgian Bay - Muskoka Region Study Team ("Study Team"), led by Hydro One Networks Inc. Participants of the Study Team 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: SGB-Muskoka Region Study Team Participants

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

3 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of Regional Planning cycle timelines and new needs in the SGB-Muskoka region, the 2nd Regional Planning cycle was triggered for the SGB-Muskoka region.

4 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the SGB-Muskoka region and includes:

- Review the status of needs/plans identified in the previous RIP; and
- Identification and assessment of any new needs (e.g. system capacity, reliability, operation, and aging infrastructure)

The Study Team may identify additional needs during the next phases of the regional planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), IRRP, and/or RIP.

5 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The geographical area of the South Georgian Bay/Muskoka Region is the area roughly bordered by West Nippising on the North-West, the Algonquin Provincial Park on the North-East, Scugog on the South, Erin on the South-West, and Grey Highlands on the West. This region is divided into two sub-regions:

- Barrie/Innisfil Sub-region: This area 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.

- Parry Sound/Muskoka Sub-region: This area encompasses the Districts of Muskoka and Parry Sound, and the northern part of Simcoe County.

The boundaries of South Georgian Bay - Muskoka Region is shown below in Fig. 1.

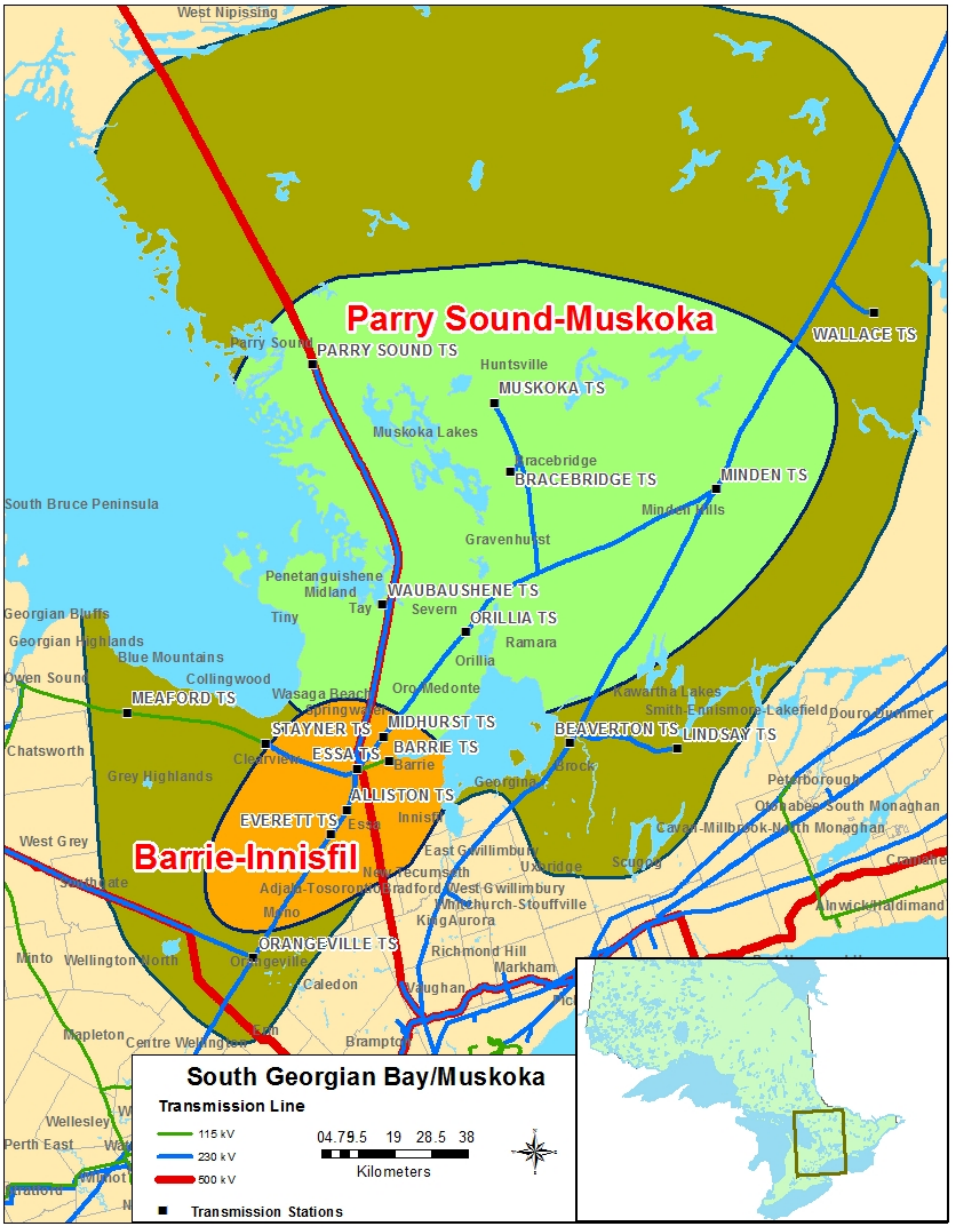

Figure 1: Geographical Area of SGB-Muskoka Region with Electrical Layout

Electrical supply to the 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) 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 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.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 2. The 500kV system is part of the bulk power system and is not studied as part of this Needs Assessment:

• Essa TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230kV auto-transformers. Essa TS also supplies the 115kV system towards Barrie TS via two 230/115kV auto-transformers.

• Eleven step-down transformer stations supply load to the north and east areas of the Region (north and east of Essa TS): Barrie TS, Beaverton TS, Bracebridge TS, Lindsay TS, Midhurst TS, Minden TS, Muskoka TS, Orillia TS, Parry Sound TS, Wallace TS, and Waubashene TS.

• Five step-down transformer stations supply load to the south and west areas of the Region (south and west of Essa TS): Alliston TS, Everett TS, Meaford TS, Orangeville TS, and Stayner TS.

• Eight 230kV circuits (E8V, E9V, E20S, E21S, E26, E27, M6E, and M7E) radiating outward from Essa TS provide local supply to the Region. These circuits are essential to the Region and will be included in the study to ensure long-term reliability. Four 230kV circuits (D1M, D2M, D3M, and D4M) entering the region from the east are also a major supply path for the Region and will be analyzed in this study.

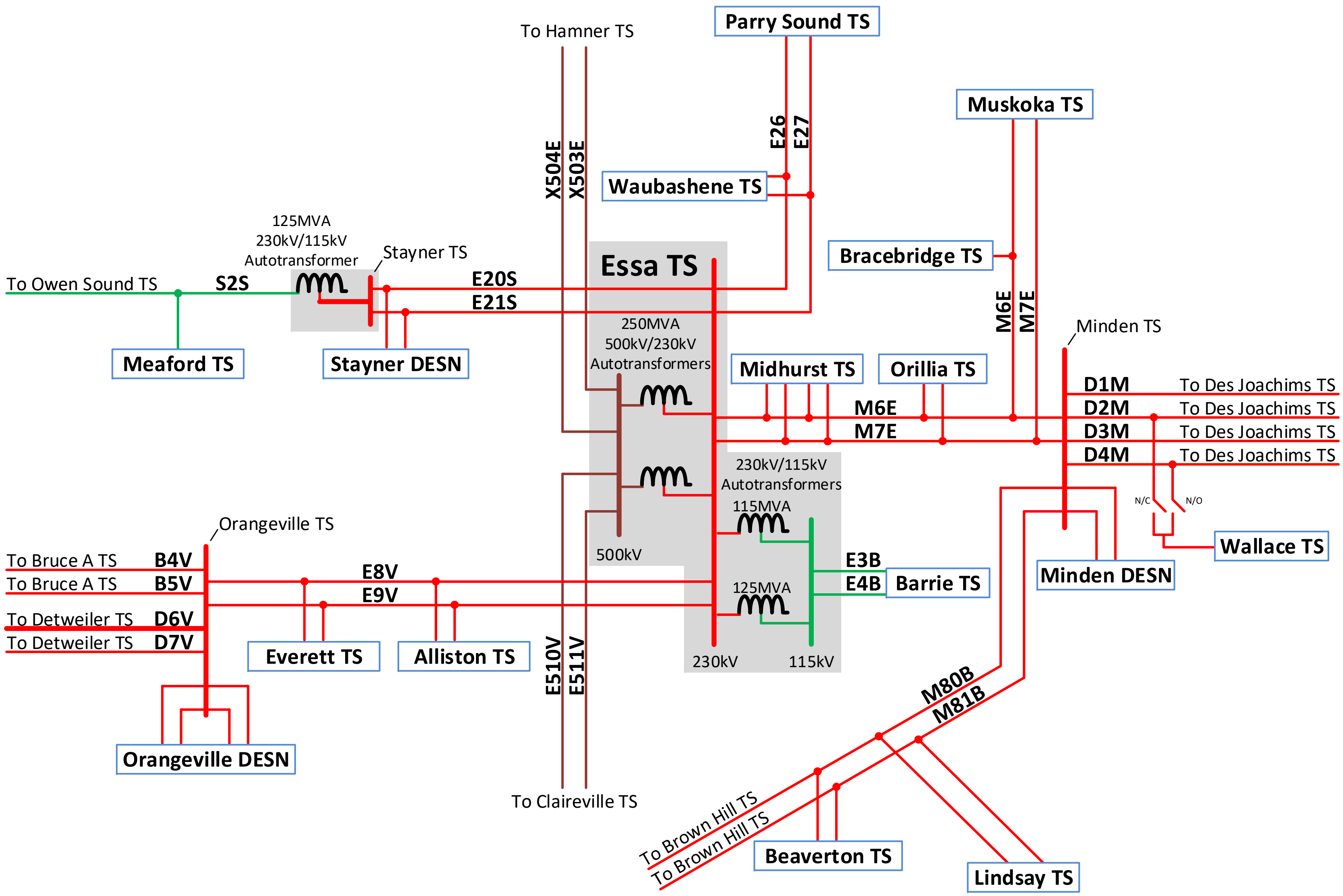

Figure 2: Single Line Diagram of South Georgian Bay - Muskoka Region

6 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the South Georgian Bay - Muskoka Region NA. The information provided includes the following:

- South Georgian Bay - Muskoka Load Forecast for all supply stations;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of life ("EOL"); and
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the SGB-Muskoka Region.

7 ASSESSMENT METHODOLOGY

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

Information gathering included:

i. Load forecast: The LDCs provided load forecasts for all the stations supplying their loads in the SGB-Muskoka region for the 10-year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the SGB-Muskoka region. The region's extreme summer non-coincident peak gross load forecast for each station were prepared by applying the LDC load forecast load growth rates to the actual 2019 summer and winter peak weather corrected loads. The summer / winter weather correction factors were provided by Hydro One. The net weather summer load forecasts were produced by reducing the gross load forecasts for each station by the % age CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that in the mid-term (5 to 10 year) time frame, contracts for existing DG resources in the region begin to expire, at which point the load forecast indicates a decreasing contribution from local DG resources, and an increase in net demand. These load forecasts for the individual stations in the SGB-Muskoka 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 due to the end of life which is 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; and
- Any major high voltage equipment reaching the end of life.

8 NEEDS

This section describes emerging needs identified in the South Georgian Bay - Muskoka Region, and also reaffirms the near, mid, and long-term needs already identified in the previous regional planning cycle.

The status of the previously identified needs is summarized in Table 2 below.

Table 2: Needs Identified in the Previous Regional Planning Cycle

Needs identified in the previous RP cycle	Needs Details	Current Status	In-Service
Supply Capacity & End-Of Life	Barrie TS transformer supply capacity will be exceeded and has consequently overload the supply circuits (E3B/E4B) InnPower is an embedded LDC supplied from a single 44kV feeder from Barrie TS and requires an additional feeder to supply its loads.	Hydro One's Barrie Area Transmission Reinforcement (BATU) project is underway This investment will address the needs identified in the last RP cycle.	2022
	Parry Sound TS supply capacity has been exceeded, and in need of upgrading. Transformers have also been assessed at being end of life and in need of replacement due to asset condition.	Hydro One will be installing new 230/44kV 83MVA transformers to address both end of life and supply capacity needs.	2024
Load Restoration	Loss of M6E and M7E will result in violation of ORTAC load restoration criteria based on the peak load	Hydro One is installing 230kV motorized disconnect switches on the M6E and M7E circuits. This will improve load restoration time. Underway	2021
End of Life Asset Replacement	Minden TS – Replacement of 230/44kV (T1/T2) transformers	Underway	2021
	Orangeville – Replacement of 230/44/27.6 (T1/T2) and 230/44 (T3/T4) transformers, low voltage switchyard	Underway	2023

8.1 End-Of-Life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

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

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

Accordingly, following major high voltage equipment has been identified as approaching its end of life over the next 10 years and assessed for right sizing opportunity.

a. 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.

b. Minden TS -Replace and upgrade existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units.

c. Orangeville TS - Replace and upgrade existing 230/44kV 83MVA transformers (T3/T4) with new 125MVA units. Replace and upgrade existing non standard 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.

d. Parry Sound TS – Replace and upgrade existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units.

e. M6E/M7E – Refurbish 25km of 230kV transmission line from Orillia TS x Coopers Fls JCT (In-Service 2024)

f. E8V / E9V – Refurbish 56km of 230kV transmission line from Orangeville TS x Essa JCT * (In-Service 2027)

g. D1M / D2M – Refurbish 62km of 230kV transmission line from Minden TS x Otter Creek JCT * (In-Service 2028)

*- further conductor samples/testing to be performed to confirm need.

8.2 Station and Transmission Capacity Needs in the South Georgian Bay - Muskoka Region

The following Station and Transmission supply capacities needs have been identified in the SGB-Muskoka region during the study period of 2020 to 2029.

8.2.1 230/115 kV, & 500/230kV Autotransformers

230/115 kV autotransformers at Essa TS(T1/T2) and Stayner TS (T1) remain within limits for the study period based on both and summer and winter demand forecast. Note: The existing Barrie area transmission upgrade project (BATU) will remove the Essa TS (T1/T2) autotransformers as part of its scope of work in 2022.

500/230kV autotransformers at Essa TS (T3/T4) remain within limits for the study period based on both and summer and winter demand forecast.

8.2.2 230 kV Transmission Lines

The 230kV M6E/M7E circuits from Essa TS to Midhurst TS exceed the Long-Term Emergency (LTE) rating within the study period. With four out of eight Des Joachims GS units are out of service (approx. 200MW) the subsequent loss of either M6E or M7E will result in the companion circuit to exceed its LTE rating. This overload occurs as early as 2023 and continues until the end of the NA study period.

8.2.3 115kV Transmission Lines

With the loss of E4B, the companion E3B circuit will exceed its summer Long-Term Emergency (LTE) rating within the study period. The scope of the Barrie Area Transmission Upgrade (BATU) project will address this finding with an expected 2022 in-service date.

8.2.4 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV TSs in the Region using both summer and winter station peak load forecasts provided by the study team. The results are as follows:

a. Waubaushene TS

Waubaushene TS has a summer 10-day LTR of 94MW and will exceed its normal supply capacity at the end of 2020 based on the summer demand forecast. Summer overloading at this station has been increasing becoming a concern and the forecast in this NA further reinforces the need for an immediate solution.[1] Initial distribution studies have shown that up to 10MW of load can be permanently transferred to Midhurst TS. This solution in combination with additional CDM/DG initiates may provide the capacity relief needed and its effectiveness will be confirmed in the next stage. While these initiatives are being explored, it is important to note that the existing 230/44kV transformers (T5/T6) are scheduled for replacement in 2030, and if needed can be upgraded to larger units to permanently alleviate supply capacity constraints. This investment can be advanced with agreement from connected LDCs if it needs to be coordinated with shorter term solutions.

b. Everett TS

Everett TS has a summer and winter 10-Day LTR of 86MW. The station supply capability is limited by a CT ratio setting on the low voltage bushing of the transformer breakers, thereby restricting the ability to utilize the full supply capability of the transformers. This restriction can be alleviated by adjusting the CT ratio of the transformer breakers, and must be completed by 2026 to allow station load to continue growing.

c. Barrie TS

Barrie TS presently has a 10-Day LTR of 109MW which will exceed its normal supply capacity in the year 2024 based on the summer demand forecast. The Barrie Area Transmission Project (BATU) project currently underway and once completed will see two new 230/44kV 125MVA transformers increasing the supply capacity of the station (170MVA in the summer), even with the new units installed, station LTR will exceed in the summer 2029. Although capacity does appear to be available for the near and mid-term, Hydro One distribution and its' embedded LDC (InnPower) will see a supply capacity constraint at the 44kV feeder level in 2025. Minor capacity increases can be accommodated on the 44kV system but only on an emergency basis, and can not be used as a permanent supply solution for increased load growth.

[1] Waubaushene TS experienced station loading in excess of 100MVA in July 2018. Although this load occurred for 2hrs and both T5/T6 were in-service, Hydro One operations were ready to initiate control actions to shed load in the event of a transformer outage.

The working group agreed that for this station, it would be reasonable to use the explicit MW values provided by the LDCs, to coincide with ongoing regulatory proceeding related to the aforementioned BATU project. [2] As such, the load forecast for each connected LDC (Shown in Appendix A) at Barrie TS is explicitly shown to provide the working group greater transparency and help to identify individual LDC needs within the study period. A near term solution is required to address this need from InnPower and should be incorporated with any long-term solutions to supply their study forecast of 93MW. InnPower will need new supply capacity into the Innisfil service territory to be provided by 2025 to service its load growth. This growth is consistent with the forecasted growth identified in the 2016 Barrie/Innisfil IRRP.

d. Parry Sound TS

Parry Sound TS has a 10-day winter LTR of 51MW and will be exceeded at the end of 2020 based on the winter demand forecast.
Parry Sound TS presently has 230/44kV 42MVA transformers (T1/T2) that have approached end of life. Hydro One will be right sizing these transformers and replacing these with two new 230/44kV 83MVA units which will provide the supply capacity needed for future load growth. These transformers are scheduled to be in-service 2024. Based on the immediate need for capacity relief at the station, Hydro One will try to expedite the replacement as quickly as possible and manage overloading risk to the existing transformers.

e. Other TSs in the Region

All the other transmission stations (TS) 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.

8.3 System Reliability, Operation and Restoration Review

No new significant system reliability and operating issues identified for this Region. Based on the net coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

[2] The forecast provided in IR response (January 9, 2020) with respect to BATU Leave to construct application (EB-2018-0017) illustrates Alectra's assigned capacity of 90MW at Barrie TS.

9 CONCLUSION AND RECOMMENDATIONS

The Study Team recommends the following –

i. Waubaushene TS – Hydro One will coordinate with the connected LDC and their embedded customers (as needed) to address the immediate supply capacity constraints that may appear within the next year. Permanent solution(s) will require further regional coordination to verify if non-wires options would be beneficial. Further regional coordination is required.

ii. Everett TS – Full utilization of the station transformer capacity is restricted by a series limiting component. A CT ratio on the low voltage bushing of the transformer breaker can be changed to allow full transformer LTR capability.
Hydro One will initiate a project directly in collaboration with the LDCs as soon as practical. Further regional coordination is not required.

iii. Barrie TS – The Barrie Area Transmission Upgrade (BATU) project is presently underway with a planned in service of 2022. No further coordination is required for the BATU project.

The working group will continue to develop supply capacity solution(s) for Innisfil area load growth. Further regional coordination is required.

iv. Parry Sound TS – The station transformer upgrade is presently underway and scheduled to be in service in 2024. Hydro One will try to expedite the replacement as quickly as possible and manage overloading risk to the existing transformers. No further regional coordination is required.

v. M6E/M7E (Essa x Midhurst) Overloading – Further regional coordination is required.

vi. Replacement of end of life assets (section 8.1 e.f.g) require further regional coordination.

Appendix A: Weather Adjusted Non-Coincident Summer Forecast

Transformer Station Name	DESN ID (e.g. T1/T2)	LTR (MVA)	LV Cap bank	LTR (MW)	Customer Data (MW)	Summer Peak Load: Historical Data (MW) 2017	2018	2019	Near Term Forecast (MW) 2020	2021	2022	2023	2024	Medium Term Forecast (MW) 2025	2026	2027	2028	2029
Alliston TS	T2	83	N	75	Gross Peak Load				44.0	44.3	44.6	44.9	45.2	45.5	45.9	46.2	46.5	46.8
					CDM (MW)				0.4	0.5	0.6	0.8	1.0	1.2	1.3	1.6	1.8	1.9
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	41.0	38.5	43.7	43.6	43.8	44.0	44.1	44.2	44.4	44.5	44.5	44.7	45.0
Alliston TS	T3/T4	111	N	100	Gross Peak Load				71.1	73.2	75.4	77.7	80.1	82.5	85.0	87.5	90.2	92.9
					CDM (MW)				0.6	0.8	1.0	1.4	1.7	2.1	2.4	3.1	3.4	3.7
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	76.7	61.8	69.0	70.5	72.5	74.4	76.3	78.3	80.3	82.5	84.4	86.8	89.2
Barrie TS	T1/T2	115	Y	109	Gross Peak (Alectra)				65.1	67.1	69.2	71.3	73.5	75.5	77.4	79.4	81.5	83.6
					Gross Peak (InnPower)				19.0	23.2	30.1	39.8	48.8	56.8	65.4	75.6	84.3	92.9
					Gross Peak (Total)				84.1	90.3	99.3	111.2	122.3	132.2	142.8	155.0	165.8	176.5
					CDM (MW)				0.7	0.9	1.4	2.0	2.7	3.4	4.1	5.5	6.3	7.0
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	93.9	119.5	127.9	83.4	89.4	97.9	109.1	119.7	128.8	138.8	149.5	159.5	169.5
Beaverton TS	T3/T4	203	Y	193	Gross Peak Load				60.2	60.8	61.3	61.9	62.4	63.0	63.5	64.1	64.7	65.3
					CDM (MW)				0.5	0.6	0.8	1.1	1.4	1.6	1.8	2.3	2.4	2.6
					DG (MW)				0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
					Net Load Forecast	52.9	55.7	59.7	59.5	59.9	60.3	60.5	60.9	61.2	61.5	61.7	62.0	62.5
Bracebridge TS	T1	83	N	75	Gross Peak Load				0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
					CDM (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					DG (MW)				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
					Net Load Forecast	13.0	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2

Everett TS	T1/T2	95	N	86	Gross Peak Load				74.6	76.8	79.0	81.3	83.7	86.2	88.7	91.3	94.0	96.8
					CDM (MW)				0.6	0.8	1.1	1.5	1.8	2.2	2.5	3.2	3.6	3.8
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	82.0	70.9	72.5	73.9	76.0	77.9	79.9	81.9	84.0	86.2	88.1	90.4	92.9
Lindsay TS	T1/T2	169	Y	161	Gross Peak Load				79.9	80.9	82.0	83.0	84.1	85.2	86.3	87.4	88.5	89.7
					CDM (MW)				0.7	0.8	1.1	1.5	1.8	2.2	2.5	3.1	3.3	3.5
					DG (MW)				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
					Net Load Forecast	72.3	72.9	78.9	79.1	80.0	80.7	81.4	82.2	82.9	83.7	84.2	85.1	86.0
Meaford TS	T1/T2	55	Y	52	Gross Peak Load				26.8	27.0	27.1	27.3	27.5	27.7	27.8	28.0	28.2	28.4
					CDM (MW)				0.2	0.3	0.4	0.5	0.6	0.7	0.8	1.0	1.1	1.1
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	30.2	33.4	26.6	26.6	26.7	26.8	26.8	26.9	27.0	27.0	27.0	27.1	27.2
Midhurst TS	T1/T2	171	Y	162	Gross Peak Load				120.6	122.9	125.3	127.7	130.2	132.7	135.3	137.9	140.6	143.3
					CDM (MW)				1.0	1.3	1.7	2.3	2.8	3.4	3.9	4.9	5.3	5.7
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	122.0	122.5	118.3	119.5	121.6	123.6	125.4	127.4	129.3	131.4	133.1	135.3	137.6
Midhurst TS	T3/T4	166	N	149	Gross Peak Load				99.7	102.5	105.4	108.4	111.4	114.6	117.8	121.1	124.6	128.1
					CDM (MW)				0.9	1.1	1.4	2.0	2.4	2.9	3.4	4.3	4.7	5.1
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	110.1	97.2	97.0	98.8	101.5	104.0	106.4	109.0	111.6	114.5	116.9	119.9	123.0
Minden TS	T1/T2	58	N	52	Gross Peak Load				42.9	43.2	43.5	43.9	44.2	44.5	44.8	45.1	45.4	45.8
					CDM (MW)				0.4	0.4	0.6	0.8	1.0	1.1	1.3	1.6	1.7	1.8
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	39.9	39.5	42.6	42.6	42.8	42.9	43.1	43.2	43.3	43.5	43.5	43.7	44.0
Muskoka TS	T1/T2	178	Y	169	Gross Peak Load				131.0	133.1	135.1	137.2	139.4	141.6	143.8	146.0	148.3	150.6
					CDM (MW)				1.1	1.4	1.9	2.5	3.0	3.6	4.1	5.1	5.6	6.0
					DG (MW)				0.1	0.1	0.1	0.1	0.1	0.1	0.1	-1.0	-1.2	-1.2
					Net Load Forecast	118.8	132.7	129.0	129.8	131.6	133.2	134.6	136.2	137.8	139.5	141.9	143.8	145.8

Orangeville TS	T1/T2	103	N	93	Gross Peak Load				58.2	58.8	59.5	60.2	60.8	61.5	62.2	62.9	63.6	64.3
					CDM (MW)				0.5	0.6	0.8	1.1	1.3	1.6	1.8	2.2	2.4	2.5
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.2
					Net Load Forecast	50.7	52.7	57.5	57.7	58.2	58.7	59.1	59.5	59.9	60.4	60.9	61.4	62.0
Orangeville TS	T3/T4	106	Y	101	Gross Peak Load				75.4	76.3	77.1	78.0	78.9	79.7	80.6	81.5	82.4	83.4
					CDM (MW)				0.7	0.8	1.1	1.4	1.7	2.1	2.3	2.9	3.1	3.3
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.2
					Net Load Forecast	70.2	69.9	74.6	74.8	75.5	76.1	76.6	77.1	77.7	78.3	78.8	79.5	80.2
Orillia TS	T1/T2	162	Y	154	Gross Peak Load				116.7	118.3	119.9	121.5	123.2	124.9	126.6	128.4	130.1	131.9
					CDM (MW)				1.0	1.2	1.6	2.2	2.7	3.2	3.6	4.5	4.9	5.2
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	96.1	107.4	115.1	115.7	117.1	118.3	119.3	120.5	121.7	123.0	123.9	125.2	126.7
Parry Sound TS	T1/T2	52	N	47	Gross Peak Load				45.1	45.5	45.9	46.3	46.8	47.2	47.6	48.0	48.4	48.8
					CDM (MW)				0.4	0.5	0.6	0.8	1.0	1.2	1.4	1.7	1.8	1.9
					DG (MW)				0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	-0.2	-0.2
					Net Load Forecast	41.0	42.5	44.8	44.8	43.6	43.9	44.1	44.3	44.5	44.8	44.9	46.7	47.1
Stayner TS	T3/T4	191	Y	181	Gross Peak Load				119.5	120.7	122.0	123.2	124.5	125.8	127.0	128.3	129.7	131.0
					CDM (MW)				1.0	1.2	1.7	2.3	2.7	3.2	3.6	4.5	4.9	5.2
					DG (MW)				0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
					Net Load Forecast	108.0	112.4	118.3	118.5	119.4	120.2	120.8	121.6	122.4	123.3	123.7	124.6	125.7
Wallace TS	T3/T4	54	N	49	Gross Peak Load				39.8	40.1	40.4	40.8	41.1	41.5	41.8	42.2	42.5	42.9
					CDM (MW)				0.3	0.4	0.6	0.7	0.9	1.1	1.2	1.5	1.6	1.7
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	27.0	37.5	39.4	39.4	39.7	39.9	40.0	40.2	40.4	40.6	40.7	40.9	41.2
Waubaushene TS	T5/T6	99	Y	94	Gross Peak Load				99.0	100.0	100.9	101.9	102.9	103.9	104.9	105.9	107.0	108.0
					CDM (MW)				0.9	1.0	1.4	1.9	2.2	2.7	3.0	3.7	4.0	4.3
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	85.3	92.2	98.0	98.1	98.9	99.5	100.0	100.7	101.2	101.9	102.2	102.9	103.8

Appendix A: Weather Adjusted Non-Coincident Winter Forecast

Transformer Station Name	DESN ID (e.g. T1/T2)	LTR (MVA)	LV Cap bank	LTR (MW)	Customer Data (MW)	Winter Peak Load												
						Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
						2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Alliston TS	T2	83	N	75	Gross Peak Load				31.3	31.5	31.7	31.9	32.1	32.3	32.5	32.7	32.9	33.1
					CDM (MW)				0.2	0.2	0.2	0.3	0.4	0.5	0.5	0.5	0.5	0.5
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	35.9	36.2	31.1	31.1	31.3	31.5	31.6	31.7	31.8	32.0	32.2	32.3	32.5
Alliston TS	T3/T4	128	N	115	Gross Peak Load				73.7	75.9	78.2	80.6	83.0	85.5	88.1	90.8	93.5	96.4
					CDM (MW)				0.4	0.4	0.6	0.8	1.0	1.2	1.4	1.4	1.5	1.5
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	57.0	57.3	71.6	73.3	75.5	77.7	79.8	82.0	84.3	86.8	89.4	92.1	94.8
Barrie TS	T1/T2	127	Y	121	Gross Peak (Alectra)				54.7	56.4	58.2	60.0	61.8	63.4	65.1	66.8	68.5	70.3
					Gross Peak (InnPower)				19.0	23.2	30.1	39.8	48.8	56.8	65.4	75.6	84.3	92.9
					Gross Peak (Total)				73.7	79.6	88.2	99.8	110.6	120.2	130.5	142.3	152.8	163.2
					CDM (MW)				0.4	0.5	0.6	1.0	1.3	1.7	2.0	2.3	2.4	2.6
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	95.1	78.4	80.9	73.3	79.2	87.6	98.8	109.3	118.5	128.5	140.1	150.4	160.6
Beaverton TS	T3/T4	224	Y	213	Gross Peak Load				83.7	84.4	85.1	85.8	86.5	87.2	87.9	88.7	89.4	90.2
					CDM (MW)				0.5	0.5	0.6	0.8	1.0	1.2	1.4	1.4	1.4	1.4
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	79.2	78.4	83.0	83.2	83.9	84.5	84.9	85.5	86.0	86.6	87.3	88.0	88.7
Bracebridge TS	T1	83	N	75	Gross Peak Load				0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
					CDM (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	0.2	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

Everett TS	T1/T2	95	N	86	Gross Peak Load				81.6	82.2	82.9	83.6	84.3	85.0	85.7	86.4	87.1	87.9
					CDM (MW)				0.5	0.5	0.6	0.8	1.0	1.2	1.3	1.4	1.4	1.4
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	78.2	76.4	80.9	81.1	81.8	82.3	82.8	83.3	83.8	84.4	85.0	85.7	86.5
Lindsay TS	T1/T2	192	Y	182	Gross Peak Load				95.5	96.7	97.9	99.1	100.3	101.5	102.8	104.0	105.3	106.6
					CDM (MW)				0.5	0.6	0.7	1.0	1.2	1.4	1.6	1.6	1.7	1.7
					DG (MW)				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
					Net Load Forecast	88.7	91.5	94.4	94.9	96.0	97.1	98.0	99.0	100.0	101.1	102.3	103.6	104.8
Meaford TS	T1/T2	62	Y	59	Gross Peak Load				34.4	34.7	34.9	35.1	35.4	35.6	35.8	36.1	36.3	36.5
					CDM (MW)				0.2	0.2	0.2	0.3	0.4	0.5	0.6	0.6	0.6	0.6
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	33.8	30.2	34.2	34.2	34.5	34.7	34.8	34.9	35.1	35.3	35.5	35.7	36.0
Midhurst TS	T1/T2	193	Y	183	Gross Peak Load				98.8	101.8	105.0	108.2	111.6	114.5	117.5	120.5	123.6	126.9
					CDM (MW)				0.6	0.6	0.7	1.1	1.3	1.6	1.8	1.9	2.0	2.0
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	103.5	100.5	100.6	98.2	101.2	104.2	107.2	110.3	112.9	115.6	118.6	121.7	124.9
Midhurst TS	T3/T4	191	N	172	Gross Peak Load				119.4	122.8	126.3	129.8	133.5	137.3	141.1	145.1	149.2	153.4
					CDM (MW)				0.7	0.7	0.9	1.3	1.6	1.9	2.2	2.3	2.4	2.4
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	123.6	91.5	116.1	118.7	122.1	125.4	128.5	131.9	135.3	138.9	142.8	146.9	151.0
Minden TS	T1/T2	64	N	58	Gross Peak Load				55.3	55.7	56.0	56.4	56.8	57.1	57.5	57.9	58.3	58.6
					CDM (MW)				0.3	0.3	0.4	0.6	0.7	0.8	0.9	0.9	0.9	0.9
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	57.0	53.3	55.0	55.0	55.4	55.6	55.8	56.1	56.3	56.6	57.0	57.3	57.7
Muskoka TS	T1/T2	209	Y	199	Gross Peak Load				164.3	166.8	169.4	172.1	174.7	177.4	180.2	183.0	185.8	188.7
					CDM (MW)				0.9	1.0	1.2	1.7	2.1	2.5	2.8	2.9	2.9	3.0
					DG (MW)				0.1	0.1	0.1	0.1	0.1	0.1	0.1	-1.2	-1.3	-1.3
					Net Load Forecast	163.7	157.8	161.8	163.2	165.7	168.1	170.2	172.5	174.8	177.2	181.2	184.2	187.0

Orangeville TS	T1/T2	121	N	109	Gross Peak Load				50.3	50.8	51.4	51.9	52.5	53.0	53.6	54.1	54.7	55.3
					CDM (MW)				0.3	0.3	0.4	0.5	0.6	0.7	0.8	0.9	0.9	0.9
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.5	-1.5	-1.5
					Net Load Forecast	49.6	47.2	49.8	50.0	50.5	51.0	51.4	51.8	52.3	52.7	54.8	55.3	55.9
Orangeville TS	T3/T4	123	Y	117	Gross Peak Load				89.1	90.0	91.0	91.9	92.9	93.9	94.8	95.8	96.9	97.9
					CDM (MW)				0.5	0.5	0.6	0.9	1.1	1.3	1.5	1.5	1.5	1.6
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.4	-1.4	-1.4
					Net Load Forecast	76.1	83.4	88.1	88.6	89.5	90.3	91.0	91.8	92.5	93.4	95.8	96.8	97.8
Orillia TS	T1/T2	184	Y	175	Gross Peak Load				127.2	128.9	130.6	132.4	134.1	135.9	137.8	139.6	141.5	143.4
					CDM (MW)				0.7	0.8	0.9	1.3	1.6	1.9	2.2	2.2	2.2	2.3
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	119.4	118.6	125.5	126.4	128.1	129.7	131.0	132.5	134.0	135.6	137.4	139.3	141.1
Parry Sound TS	T1/T2	57	N	51	Gross Peak Load				56.5	56.9	57.4	57.9	58.4	58.9	59.4	59.9	60.4	60.9
					CDM (MW)				0.3	0.3	0.4	0.6	0.7	0.8	0.9	0.9	1.0	1.0
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.8	-1.8
					Net Load Forecast	57.0	53.3	56.0	56.1	56.6	57.0	57.3	57.7	58.0	58.4	58.9	61.2	61.7
Stayner TS	T3/T4	213	Y	202	Gross Peak Load				140.0	141.1	142.1	143.2	144.3	145.3	146.4	147.5	148.7	149.8
					CDM (MW)				0.8	0.8	1.0	1.4	1.7	2.1	2.3	2.3	2.4	2.4
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	138.4	132.7	139.0	139.2	140.2	141.1	141.8	142.5	143.3	144.2	145.2	146.3	147.4
Wallace TS	T3/T4	60	N	54	Gross Peak Load				37.4	37.5	37.6	37.7	37.8	37.9	38.0	38.1	38.2	38.3
					CDM (MW)				0.2	0.2	0.3	0.4	0.5	0.5	0.6	0.6	0.6	0.6
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	38.0	35.2	37.3	37.2	37.3	37.3	37.3	37.3	37.4	37.4	37.5	37.6	37.7
Waubaushene TS	T5/T6	109	Y	104	Gross Peak Load				95.2	96.1	97.0	97.9	98.7	99.6	100.5	101.5	102.4	103.3
					CDM (MW)				0.5	0.6	0.7	1.0	1.2	1.4	1.6	1.6	1.6	1.6
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	94.0	90.5	94.4	94.7	95.5	96.3	96.9	97.6	98.2	99.0	99.9	100.8	101.7

Appendix B: Lists of Step-Down Transformer Stations

Sr. 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.	Waubashene TS	230/44

Appendix C: Lists of Transmission Circuits

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 D: Lists of LDCs in the SGB-Muskoka Region

Sr. No.	Company	Connection Type (TX/DX)
1.	Hydro One Networks Inc. (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.	Orillia Power Distribution Corp.	DX
10.	Wasaga Distribution Inc.	DX

Appendix E: Acronyms

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

Appendix G

Integrated Regional Resource Plan – Parry Sound/Muskoka

Integrated Regional Resource Plan

Parry Sound/Muskoka
May 2022

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Table of Contents

List of Figures 3

List of Tables 4

List of Appendices 5

List of Acronyms 6

1. Introduction 9

2. The Integrated Regional Resource Plan 11

2.1 Needs in the Near to Medium-Term Horizon and Recommendations 11

2.1.1 Consider Incremental Cost Effective CDM at Waubaushene TS 12

2.1.2 Like for Like Replacement for sections of 230 kV circuits M6E/M7E and D1M/D2M 12

2.2 Needs in Longer-Term Horizon and Recommendations 12

2.2.1 Supporting Community Energy Plans and Monitoring Energy Efficiency and Electrification Trends 12

3. Development of the IRRP 15

3.1 The Regional Planning Process 15

3.2 Parry Sound/Muskoka and IRRP Development 15

4. Background and Study Scope 17

4.1 Study Scope 17

5. Electricity Demand Forecast 19

5.1 Historical Electricity Demand 19

5.2 Demand Forecast Methodology 20

5.3 Gross Demand Forecast 20

5.4 Contribution of Conservation to the Demand Forecast 21

5.5 Contribution of Distributed Generation to Demand Forecast 22

5.6 Net Extreme Weather Planning Forecast 22

5.7 Load Profiling 24

5.8 Sensitivity Scenario 24

6. Electricity System Needs 25

6.1 Needs Assessment Methodology 25

6.2 Needs Identified 26

6.2.1 Station Capacity Needs 27

6.2.2 Supply Capacity Needs 28

6.2.3 End-of-Life Refurbishment Needs 28

6.2.4 Load Security and Restoration Needs 28

7. Plan Options and Recommendations 29

7.1 Options and Recommendations for Meeting Near/Medium-Term Needs 29

7.1.1 Waubaushene TS Station Capacity Need 29

7.1.2 D1M/D2M & M6E/M7E (Orillia x Copper) End-of-Life Needs 30

7.2 Options and Recommendations for Meeting Longer-Term Needs 31

7.2.1 Minden Station Capacity Needs 31

7.2.2 M6E/M7E (Minden x Copper) System Capacity Need 31

7.3 Summary of Recommended Actions and Next Steps 31

8. Engagement 33

8.1 Engagement Principles 33

8.2 Creating an Engagement Approach for Parry Sound/Muskoka 33

8.3 Engage Early and Often 34

8.4 Bringing Municipalities to the Table 35

8.5 Engaging with Indigenous Communities 35

9. Conclusion 36

List of Figures

Figure 1| Parry Sound/ Muskoka Electricity System 10

Figure 2 | Single Line Diagram of Parry Sound/ Muskoka Sub-Region 18

Figure 3 | Historical Peak Demand – Parry Sound/ Muskoka sub-region 19

Figure 4 | Illustrative Development of the Demand Forecast 20

Figure 5 | LDC Coincident Gross Winter Demand Forecast – Median Weather 21

Figure 6 | Summer Net Extreme Weather Demand Forecast 23

Figure 7 | Winter Net Extreme Weather Demand Forecast 23

Figure 8 | Summary of Location of Needs 26

Figure 9 | Waubaushene TS Capacity Needs 27

Figure 10 | Minden TS Capacity Needs 27

Figure 11 | The IESO's Engagement Principles 33

List of Tables

Table 1 | Summary of Near/Medium-term Plan for Parry Sound/Muskoka IRRP 11

Table 2 | MW Savings from Conservation and Demand Management 22

Table 3 | Summary of Needs for Parry Sound/Muskoka IRRP 26

Table 4 | Step-down Station Summer Capacity Needs 27

Table 5 | Options for Waubaushene Station Capacity Needs and Costs 30

Table 6 | Summary of Parry Sound/Muskoka IRRP Recommendations 32

List of Appendices

Appendix A: Overview of the Regional Planning Process

Appendix B: Demand Forecast

Appendix C: Options and Assumptions

Appendix D: Planning Study Results

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.

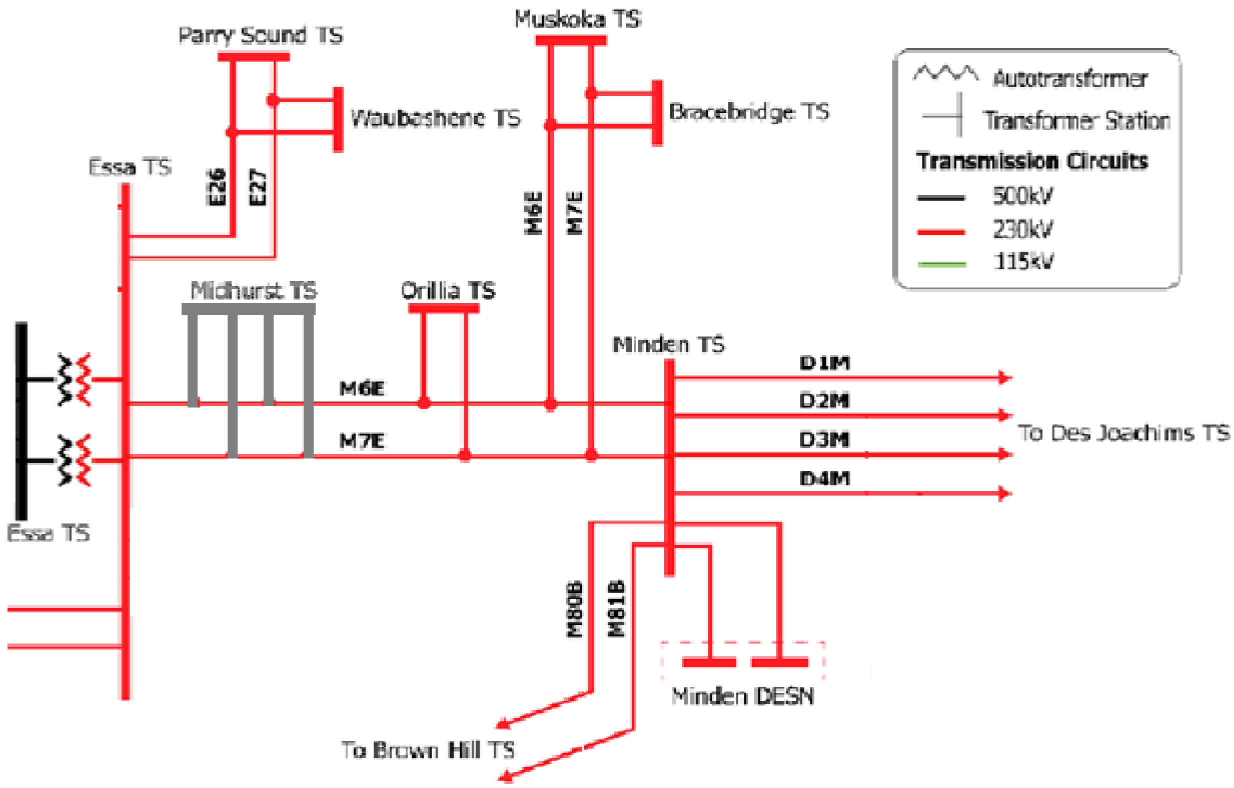
This is the second cycle of regional planning for the Parry Sound/Muskoka sub-region. This cycle began in 2020 with the publication of the South Georgian Bay Muskoka Needs Assessment Report. This was followed by a Scoping Assessment which identified needs that should be addressed through the IRRP process 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.

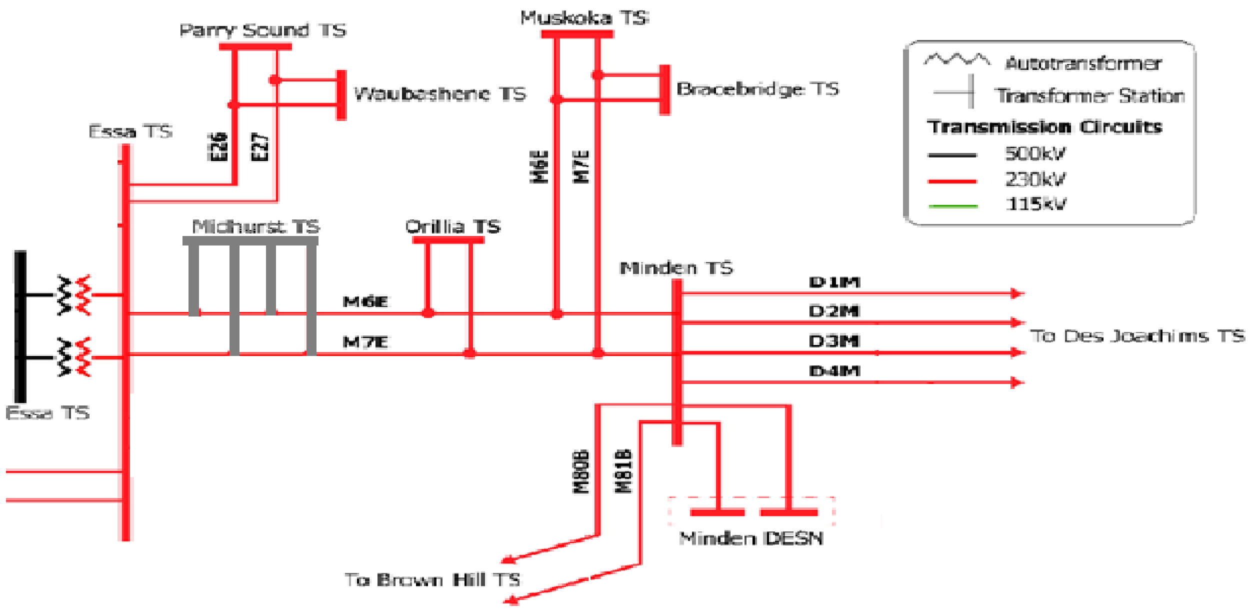
The following transmission facilities were included in the scope of this study:

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

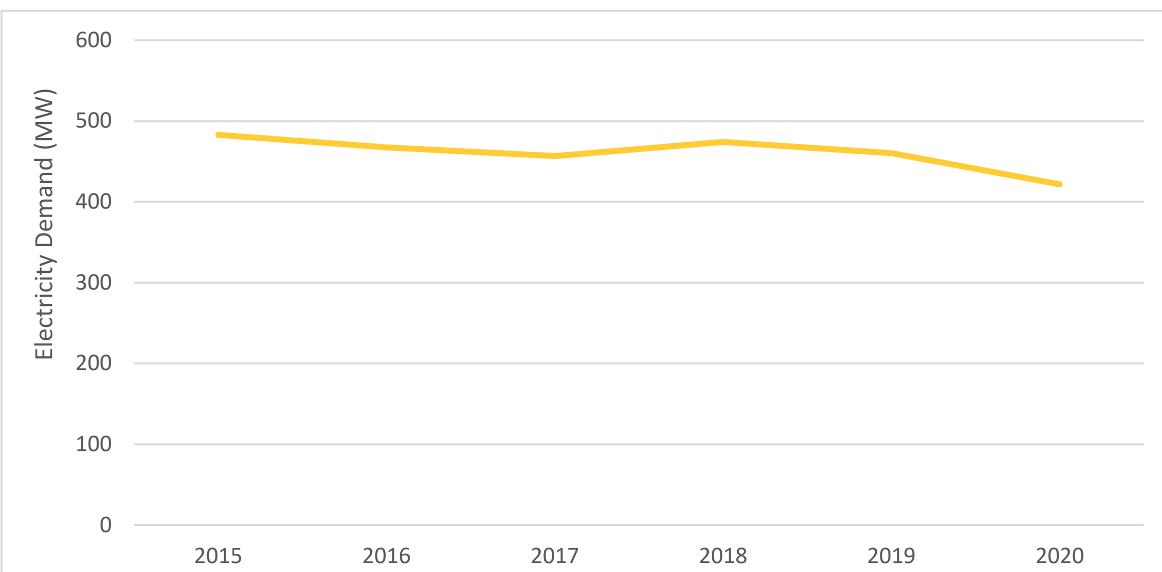
Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in the region under study. This section describes the specific details of the development of the demand forecast for the Parry Sound/Muskoka sub-region. It highlights the assumptions made for peak demand forecasts 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.

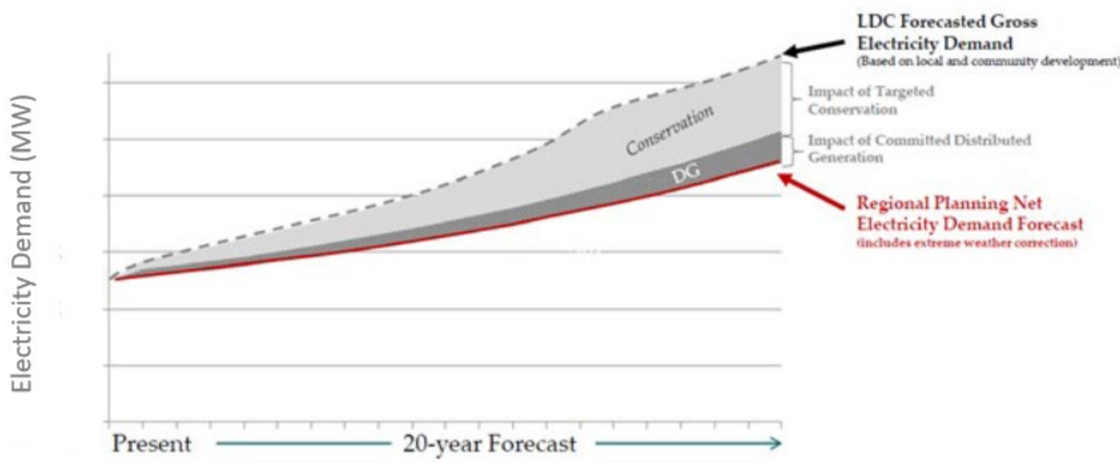
Figure 3 | Historical Winter Peak Demand – Parry Sound/ Muskoka Sub-Region



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



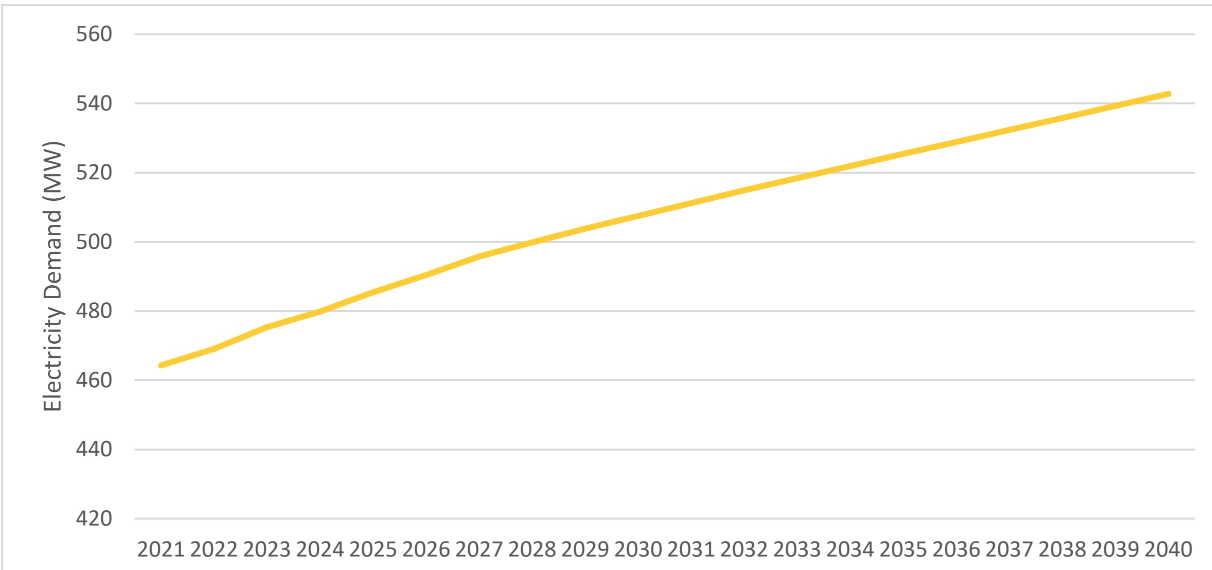
5.3 Gross Demand Forecast

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

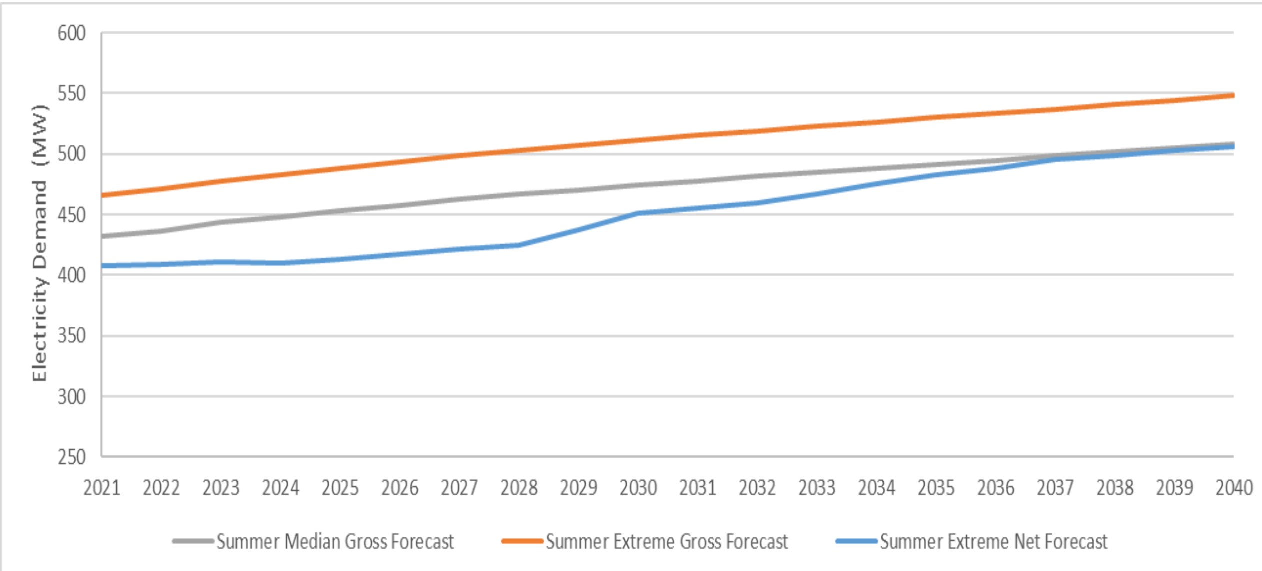
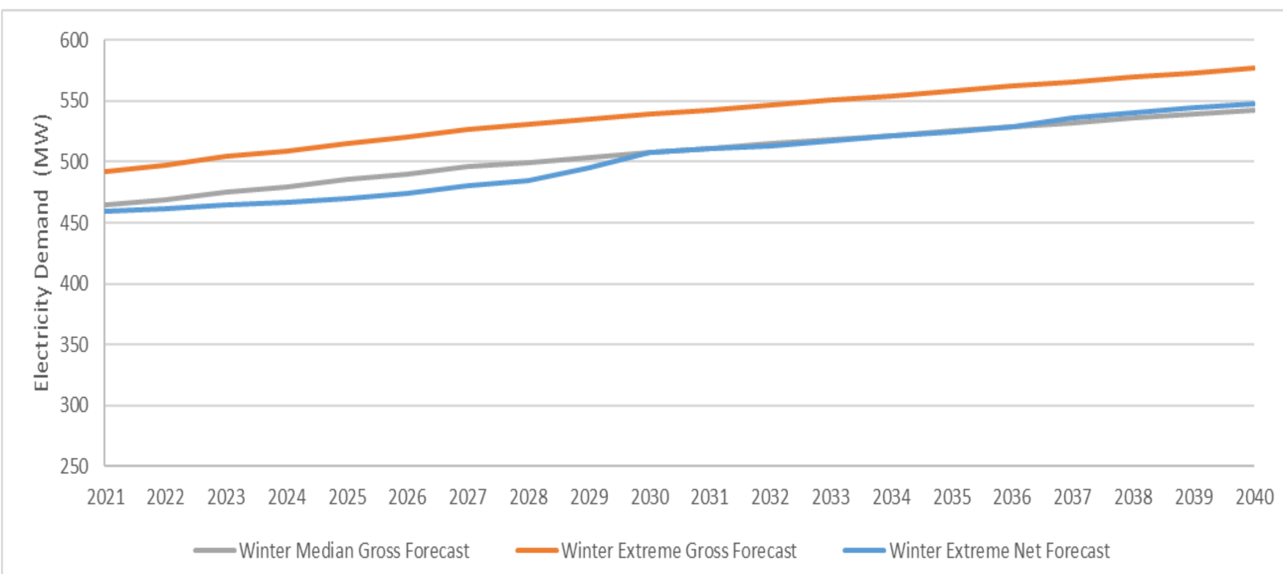


Figure 7 | Winter Net Extreme Weather Demand Forecast



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

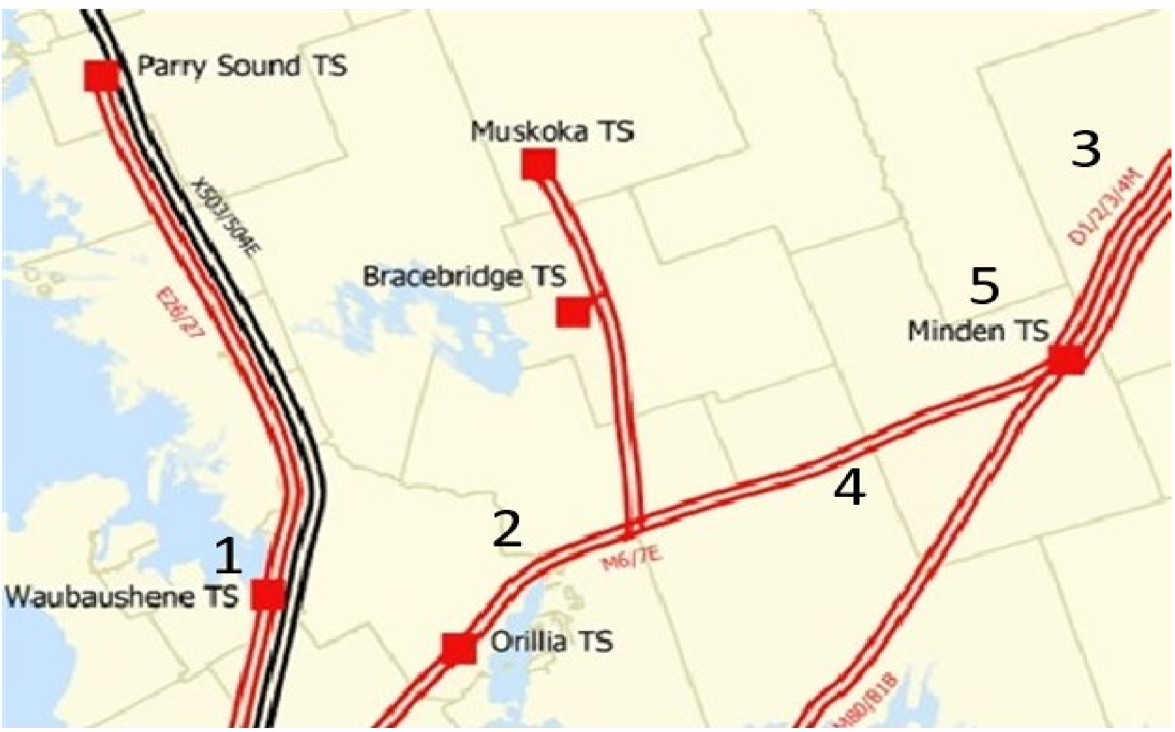
Table 3 below summarizes the needs identified by the Parry Sound/Muskoka IRRP.

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

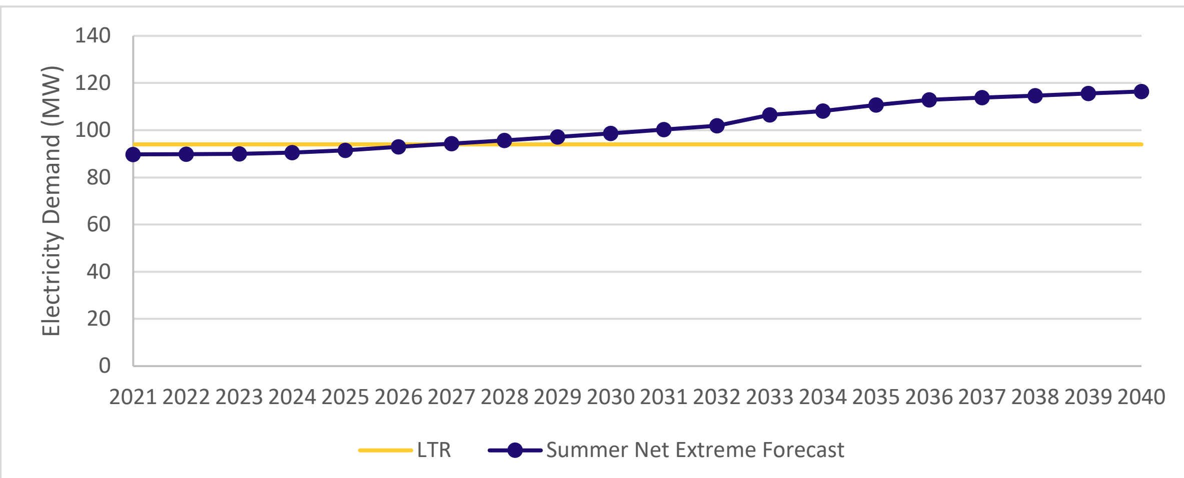
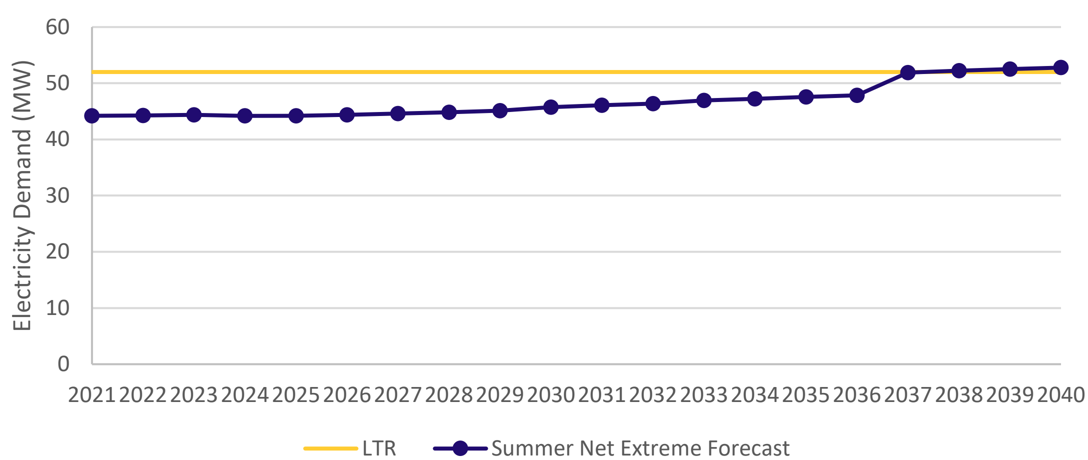


Figure 10 | Minden TS Capacity Needs



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

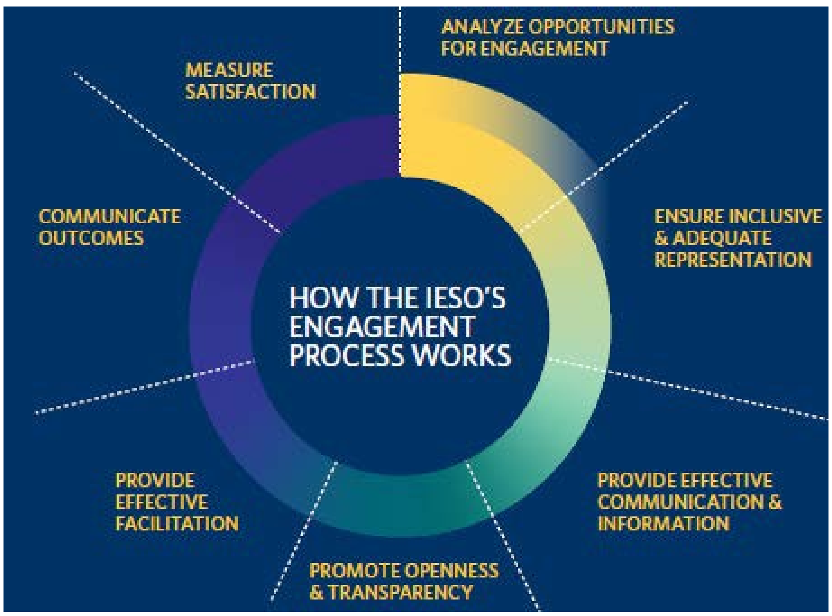
8. Engagement

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.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
linkedin.com/company/IESO

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Appendix H

Regional Infrastructure Plan – South Georgian Bay - Muskoka

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:

Company
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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TABLE OF CONTENTS

Executive Summary 5
Table of Contents 10
List of Figures 11
List of Tables 11
1. Introduction 12
1.1 Objectives and Scope 14
1.2 Structure 14
2. Regional Planning Process 15
2.1 Overview 15
2.2 Regional Planning Process 15
2.3 RIP Methodology 18
3. Regional Characteristics 20
4. Transmission Facilities Completed in the Last Ten Years and/or Underway 22
5. Forecast and Study Assumptions 23
5.1 Load Forecast 23
5.2 Other Study Assumptions 24
6. Adequacy of Existing Facilities and Regional Needs 25
6.1 500 kV and 230 kV Transmission Facilities 25
6.1.1 500/230 kV Transformation Facilities 25
6.1.2 230 & 115 kV Transmission Circuits 26
6.2 Step-Down Transformation Facilities 26
6.3 Asset Renewal for Major HV Transmission Equipment 27
6.4 Load Security and Load Restoration 29
7. Regional Plans 30
7.1 Station Capacity Needs 31
7.1.1 Everett TS 31
7.1.2 Barrie TS 31
7.1.3 Waubaushene TS 33
7.1.4 Midhurst TS and Minden TS 34
7.2 Supply Capacity Needs 34
7.3 Asset Renewal Needs for Major HV Transmission Equipment 35
7.3.1 Transmission Line Refurbishment 35
7.3.2 Transmission Station Refurbishment 35
7.4 Load Security / Restoration 38
7.5 Long Term Considerations 38
8. Conclusion and next steps 39
9. References 41
Appendix A. South Georgian Bay-Muskoka Region - Stations 42
Appendix B. South Georgian Bay-Muskoka Region - Transmission Lines 43
Appendix C. South Georgian Bay-Muskoka Region - Distributors 44

Appendix D. South Georgian Bay-Muskoka Region - Stations Load Forecast 45
Appendix E. List of Acronyms 47

LIST OF FIGURES

Figure 1-1 South Georgian Bay-Muskoka Region Map 13
Figure 2-1 Regional Planning Process Flowchart 17
Figure 2-2 RIP Methodology 19
Figure 3-1 South Georgian Bay-Muskoka Region Single Line Diagram 21
Figure 5-1 South Georgian Bay-Muskoka Region Non–Coincident Net Summer Peak Load Forecast 23
Figure 5-2 South Georgian Bay-Muskoka Region Non–Coincident Net Winter Peak Load Forecast 24

LIST OF TABLES

Table 6-1 South Georgian Bay-Muskoka Region - Lines Sections Exceeding ratings 26
Table 6-2 South Georgian Bay-Muskoka Region - Step-Down Transformer Stations............................ 26
Table 6-3 South Georgian Bay-Muskoka Region - Stations Requiring Relief in the study period (2022-2032) 27
Table 6-4 South Georgian Bay-Muskoka Region - Planned Replacement Work..................................... 28
Table 7-1 South Georgian Bay-Muskoka Region – Near, Medium and Long Term Needs...................... 30
Table 7-2 Everett TS Load Forecast 31
Table 7-3 Barrie TS Load Forecast... 32
Table 7-4 Waubaushene TS Load Forecast 33
Table 7-5 Alliston TS Load Forecast... 33
Table 7-6 Station Asset Replacement Plans 33
Table 8-1 Recommended Plans in Region over the Next 10 Years.. 39

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.

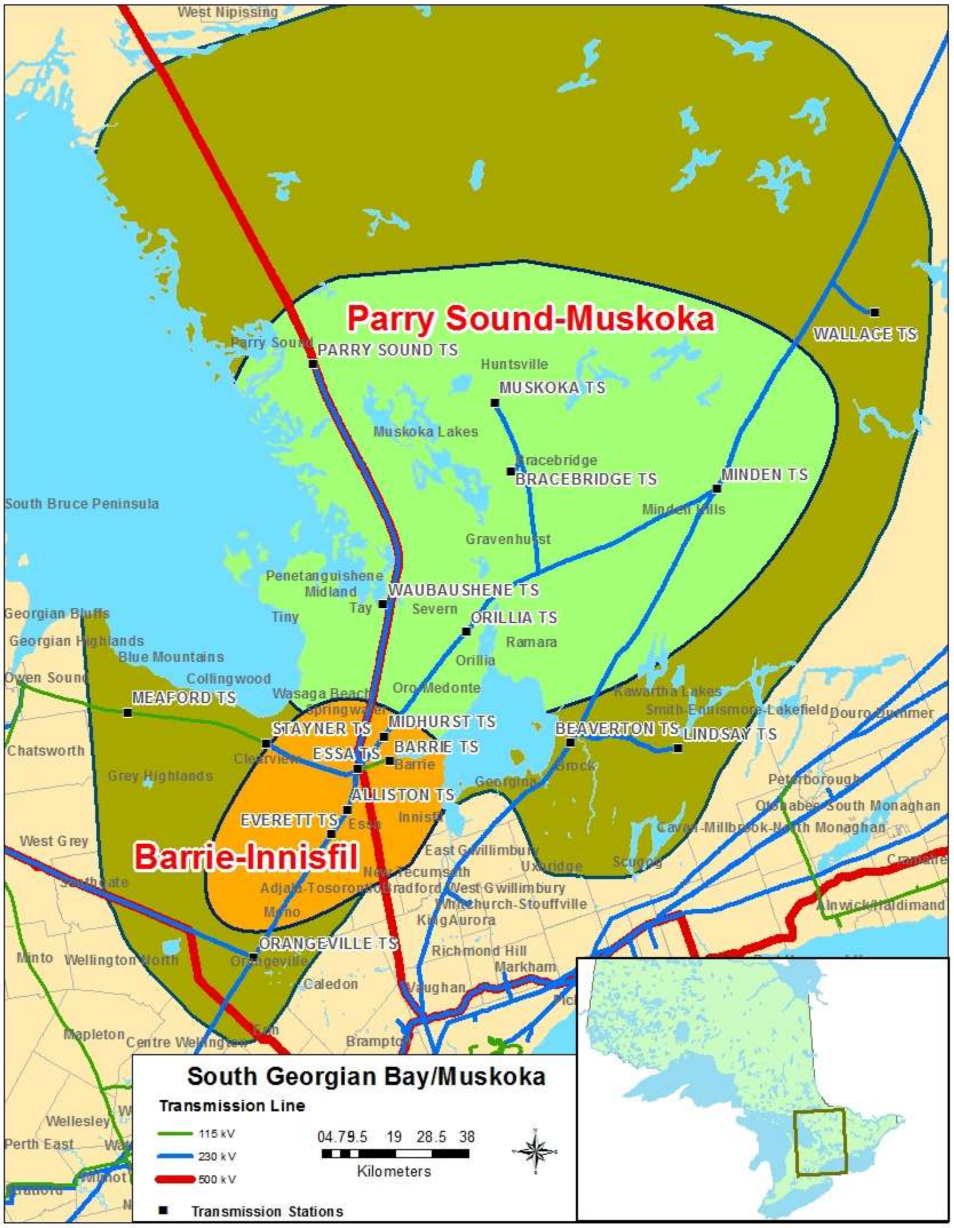


Figure 1-1 South Georgian Bay-Muskoka Region Map

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.

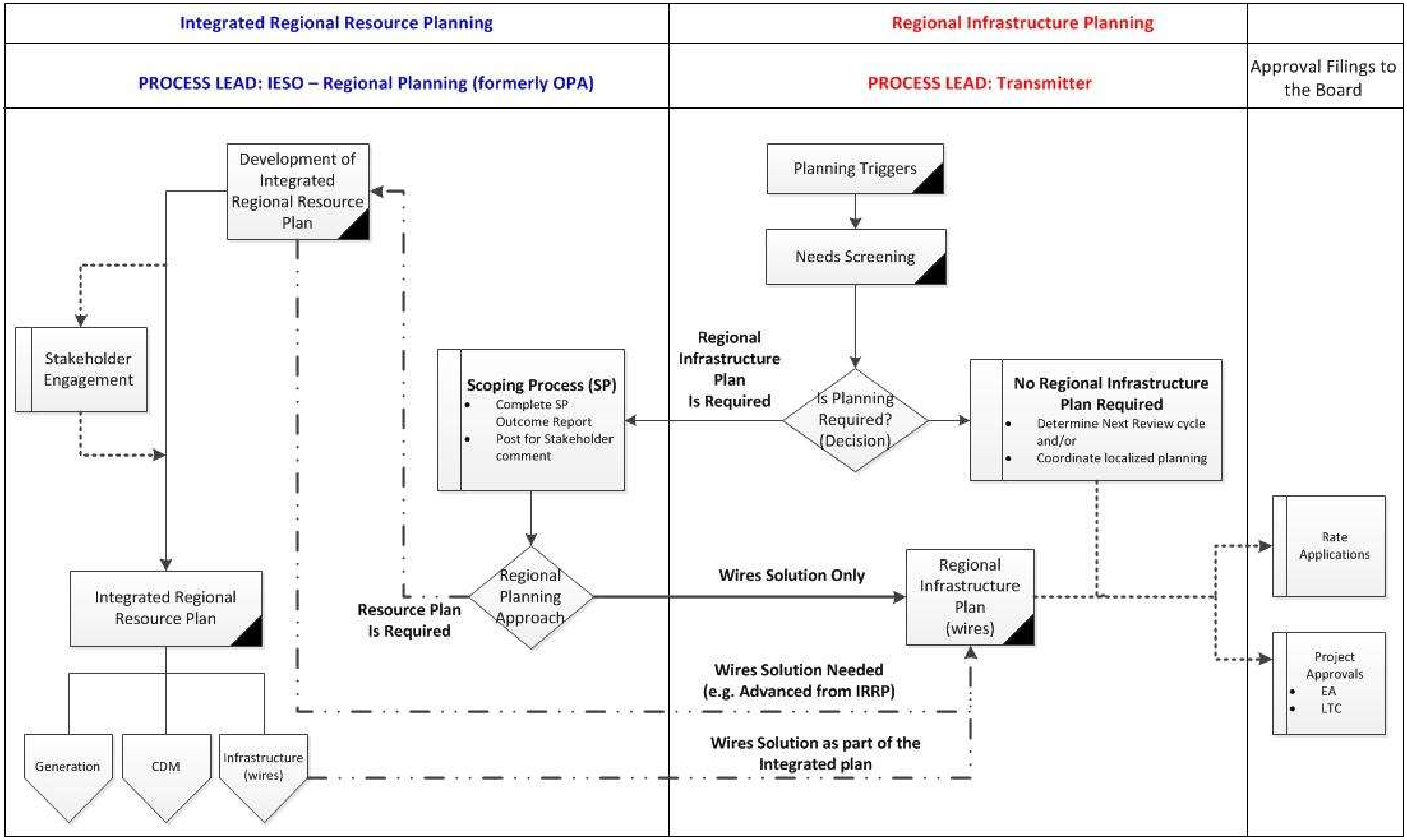


Figure 2-1 Regional Planning Process Flowchart

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.

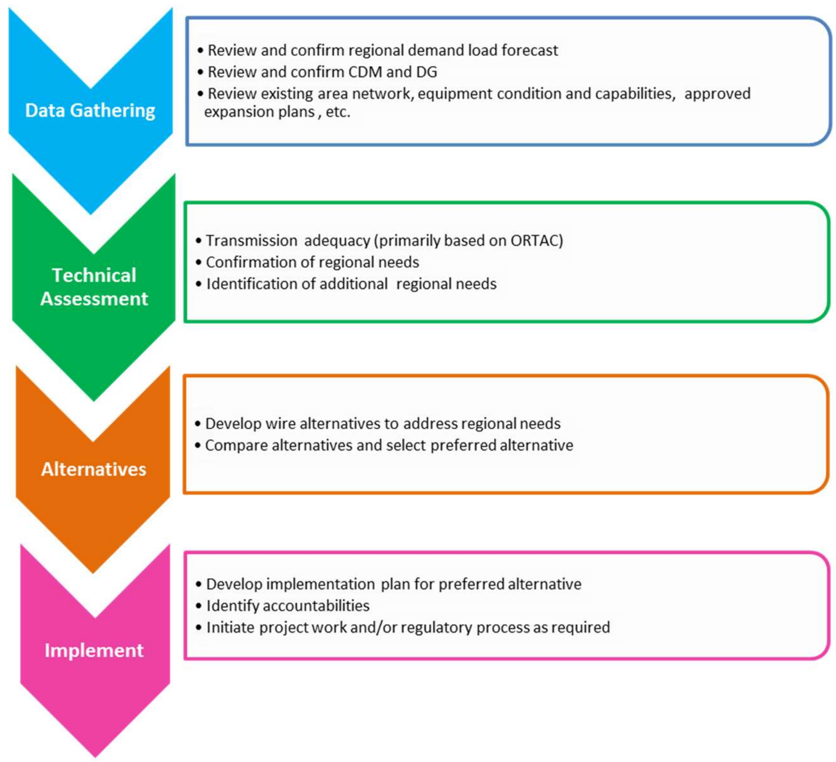


Figure 2-2 RIP Methodology

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.

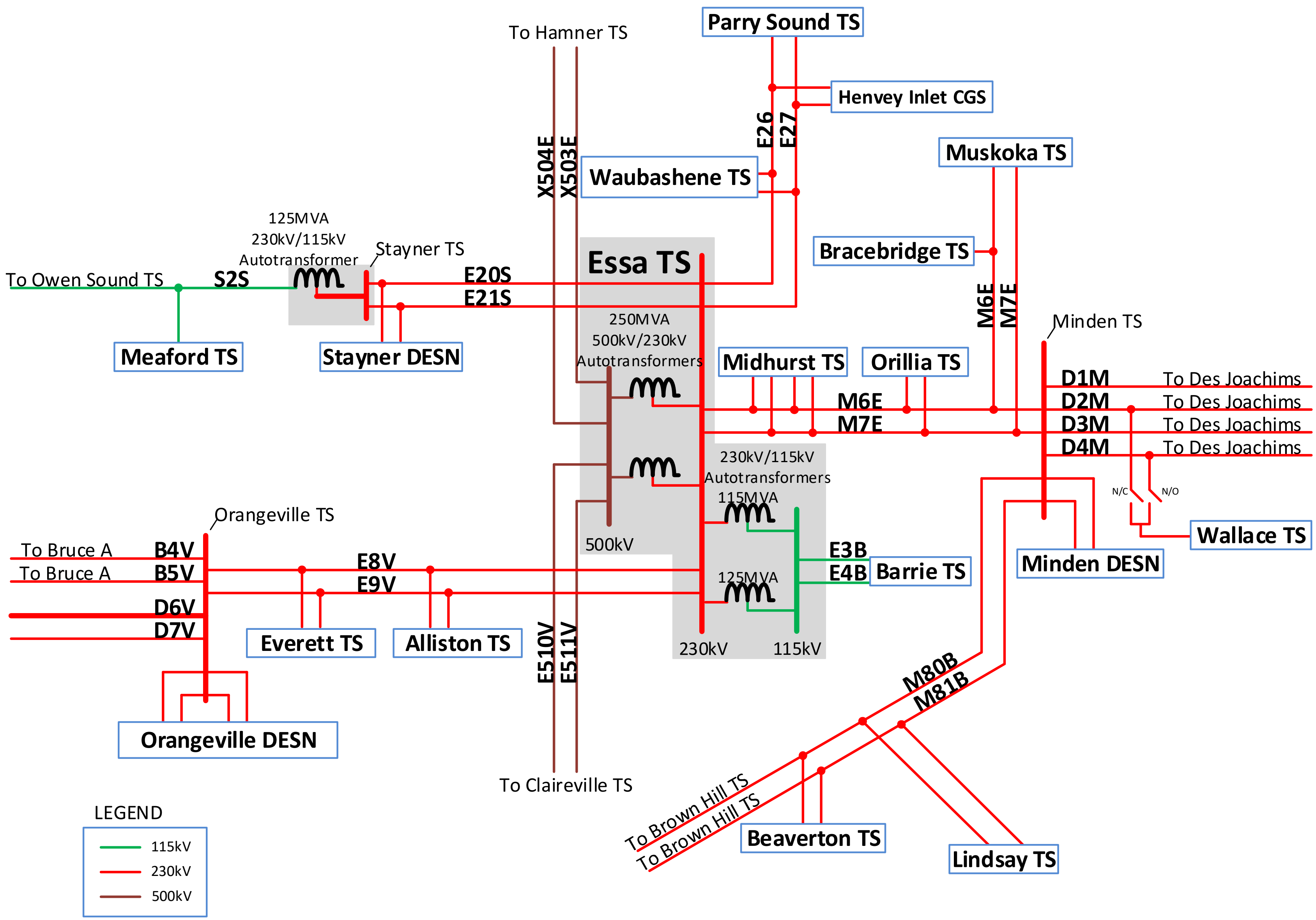
There are sixteen (16) HONI step-down transformer stations in the Region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders.

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.

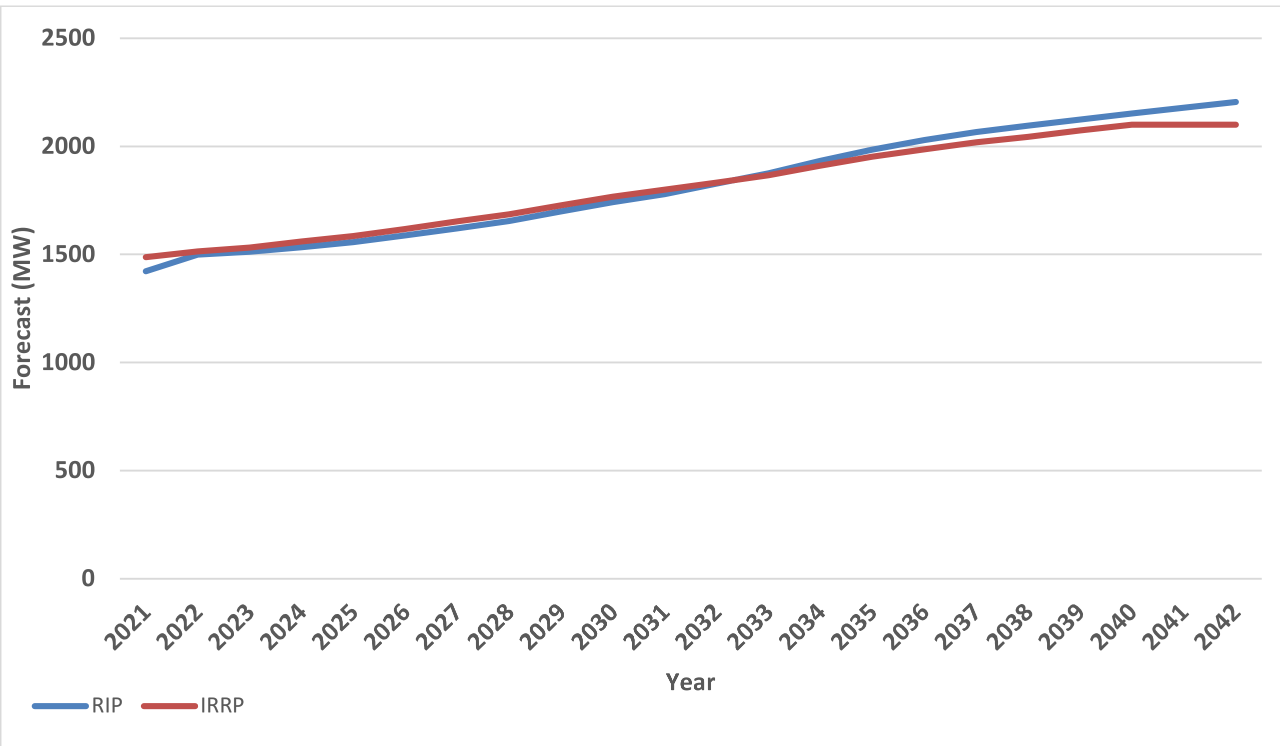


Figure 5-1 South Georgian Bay-Muskoka Region Non–Coincident Net Summer Peak Load Forecast

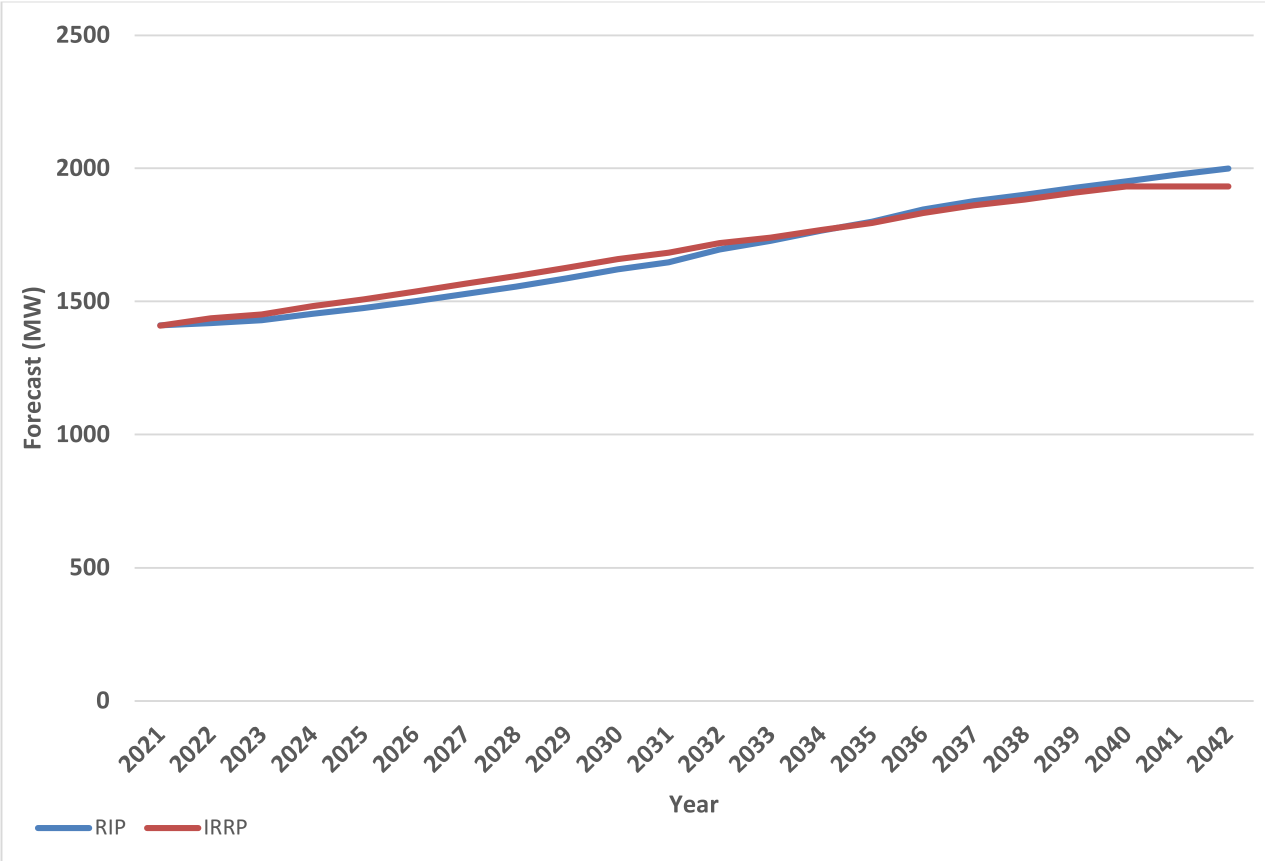


Figure 5-2 South Georgian Bay-Muskoka Region Non–Coincident Net Winter Peak Load Forecast

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

Appendix I

Regional Planning Process, Annual Status Report

Hydro One Networks Inc.
483 Bay Street
7th Floor South Tower
Toronto, Ontario M5G 2P5
HydroOne.com

Frank D'Andrea
Vice President, Reliability Standards
and Chief Regulatory Officer
T 416.345.5680
C 416.568.5534
frank.dandrea@HydroOne.com

BY EMAIL AND RESS

October 28, 2022

Ms. Nancy Marconi
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Marconi,

EB-2011-0043-2022 Regional Planning Status Report of Hydro One Networks Inc.

Section 3C.3.3 of the Transmission System Code requires transmitters to submit an annual report to the Ontario Energy Board, on November 1st of each year, that identifies the status of regional planning for all regions.

Please find attached Hydro One Networks Inc.'s 2022 Regional Planning Process Annual Status Report, pursuant to the above noted Code section.

Sincerely,

Frank D'Andrea

Frank D'Andrea

Regional Planning Process

Annual Status Report

2022

November 1st, 2022

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EXECUTIVE SUMMARY

Transmitters are required under Section 3C.3.3 of the Transmission System Code[1] (TSC) to submit an annual report to the Ontario Energy Board (OEB or Board) on November 1st of each year which identifies the status of the regional planning for their respective regions. This is the Nineth Annual Status Report produced by Hydro One Networks Inc. (Hydro One) and provides an update to the status of regional planning activities, recommended regional plans and accomplishments between November 2021 and October 2022.

Progress to Date

The first cycle of regional planning for the 21 regions was completed in 2017 as per the process developed by the Planning Process Working Group (PPWG)[2]. The second cycle is currently underway, and the third cycle has also been initiated for some regions. During these regional planning cycles, several lessons were learned to undertake improvements to the process. For instance, improvements were made with respect to replacement of major transmission assets to include justification and documentation with respect to "right sizing" of equipment. Another area where Hydro One has improved the process is with respect to the regional planning load forecast. As part of the OEB Regional Planning Process Advisory Group (RPPAG) Hydro One is involved in developing a load forecast guideline (completed) and a guideline for improving coordination between municipalities and the electricity sector for regional planning purposes (underway). These guidelines will help improve accuracy, consistency, and transparency in the development of the load forecast during the regional planning process. To align with these changes, Hydro One has also updated their internal load forecast template used to gather information from Local Distribution Companies (LDC). In addition, Hydro One has added a new section to the Needs Assessment (NA) report related to Sensitivity Analysis to capture uncertainty in the load forecast as well as variability of drivers such as DG and growing electrification trends. These improvements, described further in Section 3, have been incorporated into the process, thereby significantly enhancing the quality of the planning process and reports. The enhancement related to replacement of major transmission assets was first introduced in the Regional Infrastructure Planning (RIP) report of the first cycle (February 2017). Subsequently, this enhancement was further refined and incorporated by Hydro One into the NA and RIP reports for all regions. The first NA report to include the Sensitivity Analysis section is the Burlington to Nanticoke Region Needs Assessment (NA) report of the third regional planning cycle (Sept. 2022). At this time, no significant changes to the prioritization to initiate the third regional planning cycle are proposed except for one region (Greater Ottawa). That said, Hydro One is keeping abreast of the needs in the province on a regional basis and will advance regional planning for regions where necessary.

Since the beginning of the second regional planning cycle, the following are the significant milestones that have been accomplished (see Table 1):

- Regional Infrastructure Planning (RIP) reports for the second cycle completed for fifteen (15) regions, one (1) region underway, and the four (4) remaining regions are expected to initiate the RIP phase in Q4 2022/Q1 2023, following the completion of their respective IRRPs.
- Needs Assessment (NA) reports for the second cycle completed for all twenty (20) regions where Hydro One is the lead transmitter. For the third regional planning cycle one (1) NA was completed and three (3) NA's are underway.

- Integrated Regional Resource Planning (IRRP) reports for the second cycle completed for eleven (11) regions with four (4) currently underway.

The status of regional planning for each region is summarized in Table 1.

Table 1. Regional Planning Status Summary

Region	Sub-region	2nd Cycle (2017→)				3rd Cycle (2022→)			
		NA (1)	SA (1)	IRRP (1)(3)	RIP (1)(3)	NA (1)(3)	SA (1)	IRRP (1)	RIP (1)
Burlington to Nanticoke	Brant	May, 2017	Aug, 2017	Feb, 2019	Oct, 2019	Sep, 2022	TBD	TBD	TBD
	Bronte								
	Greater Hamilton								
	Caledonia-Norfolk								
Toronto Area	Central Downtown	Oct, 2017	Feb, 2018	Aug,2019	Mar, 2020	Dec, 2022	TBD	TBD	TBD
	Northern								
Windsor-Essex		Oct, 2017	Mar, 2018	Sep, 2019	Mar, 2020	Feb, 2023	TBD	TBD	TBD
GTA North	York	Mar, 2018	Aug, 2018	Feb, 2020	Oct, 2020	Jul, 2023	TBD	TBD	TBD
	Western								
Greater Ottawa	Ottawa	Jun, 2018	Sep, 2018	Mar, 2020	Dec, 2020	Dec, 2022	TBD	TBD	TBD
	Outer Ottawa								
Kitchener-Waterloo-Cambridge-Guelph		Dec, 2018	May, 2019	May, 2021	Dec, 2021	Apr, 2024	TBD	TBD	TBD
GTA West	Northwestern	May, 2019	Aug, 2019	Jul, 2021	Feb, 2022	Sep, 2024	TBD	TBD	TBD
	Southern								
Greater Bruce/Huron		May, 2019	Sep, 2019	Sep, 2021	Apr, 2022	Sep, 2024	TBD	TBD	TBD
East Lake Superior		Jun, 2019	Oct, 2019	Apr, 2021	Oct, 2021	Oct, 2024	TBD	TBD	TBD
GTA East	Pickering-Ajax-Whitby	Aug, 2019	*Not Required*	*Not Required*	Feb, 2020	Dec, 2024	TBD	TBD	TBD
	Oshawa-Clarington								
Peterborough to Kingston		Feb, 2020	May, 2020	Nov,2021	May, 2022	Jun, 2025	TBD	TBD	TBD
South Georgian Bay/Muskoka	Barrie/Innisfil	Apr, 2020	Nov, 2020	May, 2022	Dec, 2022	Aug, 2025	TBD	TBD	TBD
	Parry Sound/Muskoka								
London Area	Greater London	May, 2020	*Not Required*	*Not Required*	Aug, 2022	Sep, 2025	TBD	TBD	TBD
	Alymer-Tillsonburg								
	Strathroy								
	Woodstock								
	St. Thomas								
Sudbury/Algoma		Jun, 2020	*Not Required*	*Not Required*	Dec, 2020	Oct, 2025	TBD	TBD	TBD

Region	Sub-region	2nd Cycle (2017→)				3rd Cycle (2022→)			
		NA (1)	**SA** (1)	**IRRP** (1)(3)	**RIP** (1)(3)	**NA** (1)(3)	**SA** (1)	**IRRP** (1)	**RIP** (1)
Northwest Ontario	North of Dryden Greenstone-Marathon Thunder Bay West of Thunder Bay	Jul, 2020	Jan, 2021	Dec, 2022	Jul, 2023	Nov, 2025	TBD	TBD	TBD
Chatham/Lambton/Sarnia		Sep, 2021	Dec, 2021	*Not Required*	Aug, 2022	Jan, 2027	TBD	TBD	TBD
Niagara		May, 2021	Aug, 2021	Nov, 2022	Jun, 2023	Sep, 2026	TBD	TBD	TBD
North/East of Sudbury		May, 2021	Aug, 2021	Feb, 2023	Sep, 2023	Sep, 2026	TBD	TBD	TBD
Renfrew		May, 2021	Aug, 2021	Dec, 2022	Jul, 2023	Sep, 2026	TBD	TBD	TBD
St. Lawrence (2)		Sep, 2021	*Not Required*	*Not Required*	Mar, 2022	Jan, 2027	TBD	TBD	TBD
North of Moosonee		*Hydro One Transmission is not the lead transmitter in this region. Status to be provided by lead transmitter.*							

Notes: (1): NA: Needs Assessment; SA: Scoping Assessment; IRRP: Integrated Regional Resource Plan; RIP: Regional Infrastructure Plan
(2): Note that St. Lawrence 2nd cycle NA was initiated two (2) months over the five (5) year period because of an error in oversight.
(3): These are tentative dates of completion based on Regional Planning Process timeline requirements.

TABLE OF CONTENTS

Executive Summary 2
1. Introduction 6
2. Regional Planning Process Overview 7
 2.1 Regions 8
 2.2 Conservation & Demand Management (CDM) and Distributed Energy Resources (DER) 10
3. Lessons Learned and Process Improvements 11
 3.1 Better Address Asset Replacement Needs in the Regional Planning Process 11
 3.2 Load Forecast Guideline 12
 3.3 Improving Coordination between Municipalities and the Electricity Sector for Regional Planning Purposes 12
 3.4 Other Process Improvements 13
4. Status of Regions 16
 4.1 Burlington to Nanticoke 16
 4.2 Toronto 19
 4.3 Windsor-Essex 21
 4.4 GTA North 23
 4.5 Greater Ottawa 25
 4.6 Kitchener-Waterloo-Cambridge-Guelph (KWCG) 29
 4.7 GTA West 32
 4.8 Greater Bruce/Huron 34
 4.9 East Lake Superior 36
 4.10 GTA East 40
 4.11 London Area 41
 4.12 Peterborough to Kingston 43
 4.13 South Georgian Bay/Muskoka 45
 4.14 Sudbury/Algoma 47
 4.15 Northwest Ontario 49
 4.16 Chatham/Lambton/Sarnia 52
 4.17 Niagara 54
 4.18 North/East of Sudbury 56
 4.19 Renfrew 57
 4.20 St. Lawrence 58
 4.21 North of Moosonee 59
5. Conclusion 60
6. References 62
Appendix A. Conservation, Distributed Generation, and Other Initiatives 63
 A.1 Conservation Achievement 63
 A.2 Distribution Energy Resources 64
 A.3 Other Initiatives 70
Appendix B. Planning Status Letters 72

1. INTRODUCTION

The process for electric power system planning in the Province of Ontario underwent a procedural change in 2013. A new regional planning process, which enables transparent, coordinated and cost-effective planning of regional transmission and distribution systems, was mandated by the Ontario Energy Board (OEB or Board) on August 26, 2013 through amendments to both the Transmission System Code[1] (TSC) and the Distribution System Code[3] (DSC). This process is outlined in the Planning Process Working Group's (PPWG) Report to the Board, titled "The Process for Regional Infrastructure Planning in Ontario"[2], revised May 17, 2013.

As per Section 3C.3.3 of the TSC, transmitters are required to submit an annual report to the Board on November 1st of each year, which identifies the status of the regional planning process and its deliverables in their respective regions. This Nineth (2022) Annual Status Report, produced by Hydro One Networks Inc. (Hydro One), provides an update to the accomplishments and progress status of the regional planning activities from November 2021 to October 2022. It also identifies plans and projects already in execution to address new and previously identified needs.

The Report is structured as follows:

- Section 2 provides a brief overview of the regional planning process.
- Section 3 identifies lessons learned and improvements made to the regional planning process.
- Section 4 discusses the various regional planning activities, plans, and projects completed or being undertaken.
- Section 5 provides a brief summary of the status of regional planning and its accomplishments over the last year.
- Section 6 lists all reference documentation.

2. REGIONAL PLANNING PROCESS OVERVIEW

Bulk System Planning, Regional Planning and Distribution Planning are the three levels of planning for the electricity system in Ontario. Bulk system planning typically looks at issues that impact the system on a provincial level and requires longer lead time and larger investments. Comparatively, planning at the regional and distribution levels look at issues on a more regional or localized level. Typically, the most essential and effective regional planning horizon is the near- to medium-term (1-10 years), whereas long-term (10-20 years) regional planning mostly provides a future outlook with little details about investments because the needs and other factors may vary over time. On the other hand, bulk system plans are developed for the long term because of the larger magnitude of the investments.

The regional planning process begins with a Needs Assessment (NA) which is led by the transmitter to identify, assess and document which of the needs a) can be addressed directly between the customer and the transmitter along with a recommended plan, and b) that require further regional coordination and identification of Local Distribution Companies (LDCs) to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the Technical Working Group (TWG) as to whether further regional coordination is necessary to address some or all the regional needs. If no further regional coordination is required, recommendation to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The Region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs a) are local in nature, b) require limited investments in wires (transmission or distribution) solutions, and c) do not require upstream transmission investments.

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

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

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

As a final step of the regional planning process, Hydro One as the lead transmitter undertakes the development of a RIP with input from the TWG for the region and publishes a RIP report. The RIP reports include a complete discussion of all options and recommended plans and wire infrastructure investments within each region identified in earlier phases. As a result, RIP reports are also referenced as supporting evidence in a cost of service or Leave-to-Construct approval application.

Figure 1 illustrates the various steps of the regional planning process that include NA (also known as Needs Screening), SA (also known as Scoping Process), LP, IRRP, and RIP.

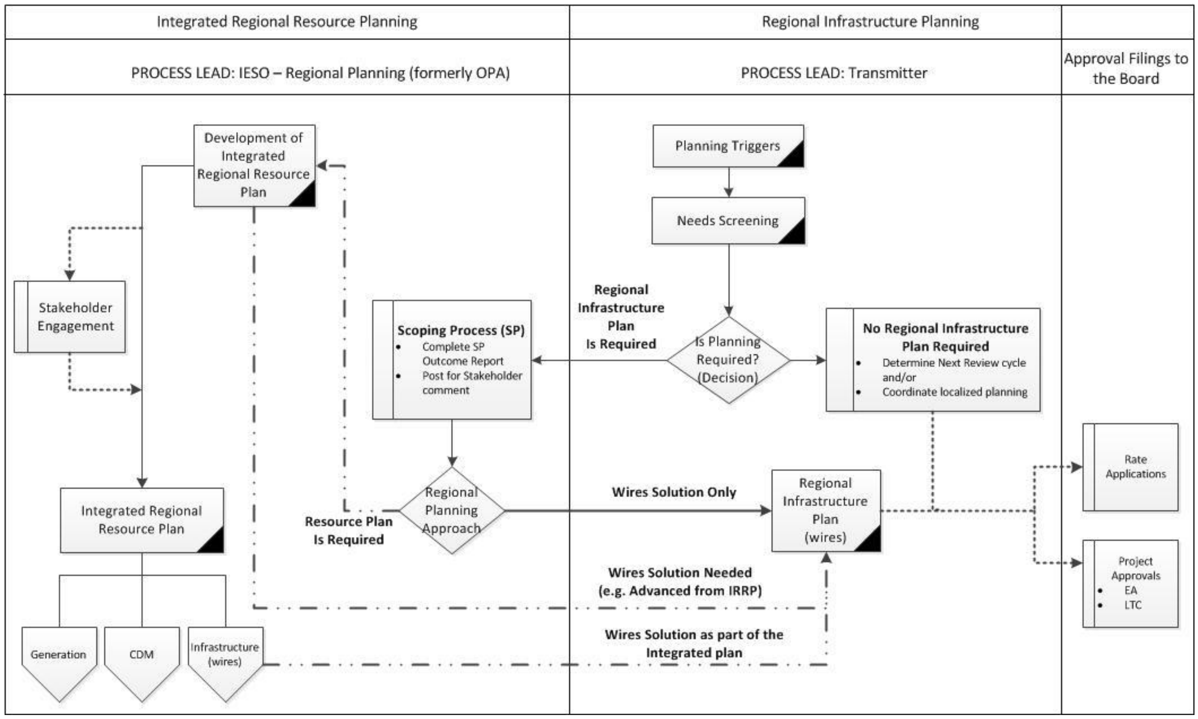


Figure 2-1. Regional Planning Process Flowchart

2.1 Regions

The province has been divided into 21 regions to undertake regional planning. In the first cycle, 21 regions were placed into 3 groups to manage and prioritize regional planning activities. Subsequently, regional planning is initiated every five (5) years or earlier if required to meet emerging needs.

Hydro One is the lead transmitter in all regions, except the East Lake Superior[1] and North of Moosonee Regions. For each regional planning activity at the regional or sub-regional level, a Technical Working Group (TWG) is established for each region with representatives from the IESO, Hydro One, and respective LDCs of the area. During the regional planning process, the TWG may further divide a region into two or more sub-regions based on electrical characteristics, contiguity and for efficient and effective assessment.

The planning regions are listed in Table 2 and shown pictorially in Figure 2-2.

[1] Hydro One Sault Saint Marie, an affiliate of Hydro One Networks, is the lead transmitter for East Lake Superior. This Report includes the status of the regional planning activities in the East Lake Superior Region.

Table 2. Regional Planning Regions

Burlington to Nanticoke	Northwest Ontario	Chatham/Lambton/Sarnia
Greater Ottawa	Windsor-Essex	Greater Bruce/Huron
GTA East	East Lake Superior	Niagara
GTA North	London Area	North of Moosonee
GTA West	Peterborough to Kingston	North/East of Sudbury
KWCG	South Georgian Bay/Muskoka	Renfrew
Toronto	Sudbury/Algoma	St. Lawrence

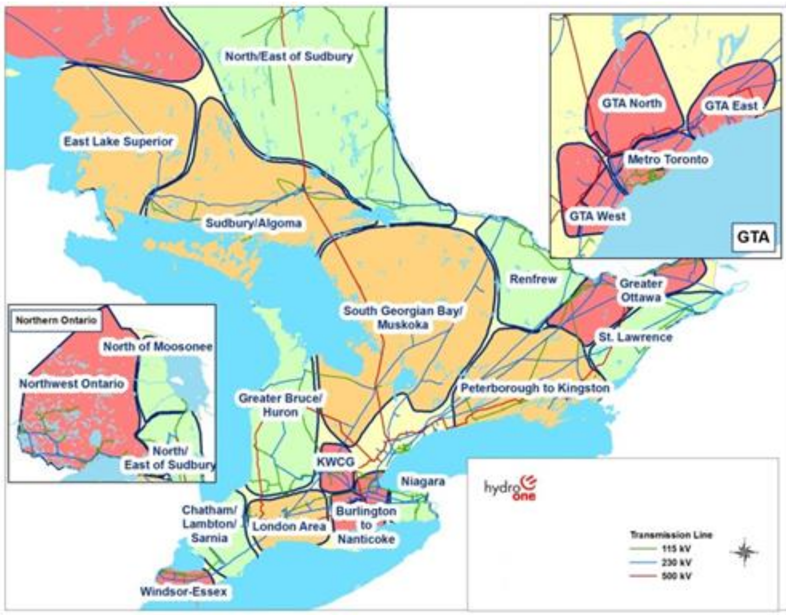


Figure 2-2. Regional Planning Regions

2.2 Conservation & Demand Management (CDM) and Distributed Energy Resources (DER)

CDM is considered at each step of the regional planning process. It is based on input from municipalities, requirements of individual LDCs to comply with conservation targets that are to be achieved through the provision of CDM programs to each customer segment in their service territories[4]. The CDM information is provided by the IESO and prepared jointly by the LDCs for regional planning assessments.

Consistent with Section 21.2.2 (g) of the IESO License and Section 3C.3 of the TSC[1], the IESO provides peak demand offsets resulting from LDCs' CDM programs. It is worth noting that peak demand offsets resulting from LDCs' CDM programs are the total offsets to be achieved by the LDC within its service territory and hence may not be limited to or reflective of offsets within the specific region. The IESO also provides total installed and effective capacity of the IESO contracted DG projects which are either in service or are under development for regions or sub-regions for which an IRRP is completed. The CDM and DG summary provided by the IESO is attached in Appendix A.

Both, CDM and DG information is used to develop a net forecast from the gross load forecast provided by the LDCs.

3. LESSONS LEARNED AND PROCESS IMPROVEMENTS

During the first and second cycle of the regional planning process, several lessons and opportunities for improvement were identified pertaining to the regional planning process and its deliverables following a thorough internal review of the regional planning process, discussions with regional Technical Working Groups (TWG) (consisting of LDCs, IESO, and Hydro One as lead transmitter), and recommendations from the OEB Regional Planning Process Advisory Group ("RPPAG"). Hydro One implemented several measures to improve the existing consultation with TWG members, planning processes, and deliverables. Some of the key improvements since our 2021 Annual Status Report include the following and are described in further detail in the sections below:

- Formalized the process to better address asset replacement needs in the regional planning process;
- Developed a load forecast guideline for regional planning; and,
- Developing a guideline for improving coordination between municipalities and the electricity sector for regional planning purposes

3.1 Better Address Asset Replacement Needs in the Regional Planning Process

Since the end of the first cycle, Hydro One implemented improvements to the planning process related to asset replacement needs by providing better rationale and documentation with respect to "right sizing" of equipment. In 2022, the RPPAG formalized the process and recommended that going forward all transmission asset owners (TAO) provide a 10-year outlook related to their major transmission assets requiring replacement during the Needs Assessment (NA) phase.

Managing the replacement of transmission and distribution infrastructure is the primary accountability of asset owners for its safe, secure, and reliable operation. Major assets such as transformers, breakers, and conductors/cables require specialized expertise to assess and plan replacement. However, sometimes there is a broader planning opportunity and as a result, Hydro One developed an internal process to collect and share best available information on major high voltage transmission equipment planned for replacement within the next 10 years with the Regional Planning TWG. The major high voltage equipment information shared and discussed as part of this process is listed below:

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

The assessment and documentation are first undertaken in the NA phase by the TWG (i.e., Hydro One, IESO, and affected LDCs) for the applicable region. As part of this analysis, different options are evaluated, and a preferred replacement plan is recommended along with its rationale. The TWG reviews the load forecast that considers several inputs such as load growth due to changing customer requirements, CDM, and DER to determine the recommended plan for addressing the asset replacement need(s). The assessment includes, but is not limited to: downsizing/eliminating equipment by transferring load to other existing facilities; replacing equipment with similar equipment of same or higher ratings; and, consideration of economical and practical implementation of incremental CDM/DER to defer or eliminate the need while maintaining safe and reliable service to customers. The underlying goal is to “right size” the replacement asset. Consistent with the regional planning process, all affected transmission customers (e.g., LDCs, industrial, etc.) directly connected to the asset(s) being assessed are consulted and engaged by the transmitter to obtain input regarding their expected needs before a preferred replacement plan is implemented.

Asset replacement needs that do not require further regional coordination (i.e., SA, IRRP, RIP) following the NA phase are addressed by Hydro One, as a transmitter, in coordination with the affected LDC(s). In doing so, Hydro One coordinates the replacement plan and related outages. Asset replacement needs that do require further assessment and regional coordination include those that provide an opportunity for cost effective reconfiguration (e.g. significant rebuild of a station), greater reliability, or better capacity planning to address a broader regional need(s). In such cases, further assessment of these needs will be undertaken in the next phase(s) of the regional planning process (i.e., SA, IRRP, and RIP) where the TWG will further review options and develop a preferred replacement plan.

3.2 Load Forecast Guideline

This document was developed 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. It is meant to enhance clarity, consistency, and transparency in the development of the load forecast and remain flexible to future evolution. The Guideline was finalized and adopted by the RPPAG in October 2022. Hydro One has also updated its internal load forecast template to align with the Guideline and provide further clarity to LDCs in providing their load forecast information.

3.3 Improving Coordination between Municipalities and the Electricity Sector for Regional Planning Purposes

Hydro One is actively involved in the RPPAG Municipal Subgroup to develop a guideline for municipalities to provide more specific information to LDCs, Hydro One and IESO that can be translated into load forecasts that are used in the regional planning process. This will result in better coordination in developing load forecasts which underpin the identification of needs as well as enhance two-way communication through a better understanding among municipalities of LDC information needs. This guideline is expected to be completed in Q4 2022.

3.4 Other Process Improvements

Some of the other process improvements made by Hydro One are listed below:

- Regional Planning Report Templates – various updates including a new section on “Sensitivity Analysis” in the NA report (beginning with third cycle Burlington to Nanticoke Region NA report).
- Utilizing revised local planning guidelines to aid the TWG in determining when specific needs that are local in nature can be more efficiently addressed by Hydro One and affected LDC(s).
- Pre-Regional Planning Input – since the second regional planning cycle, prior to start of the NA and RIP phase, Hydro One implemented one-on-one pre-Regional Planning meetings with key stakeholders such as LDCs to better understand their emerging needs and collect relevant information. These meetings have resulted in enhanced collaboration and efficiency during regional planning meetings with TWG members by having a head start in determining emerging needs, discussing specific LDC issues and concerns that may have an impact on regional planning, and overall report quality enhancements. For example, a pre-Regional Planning meeting held with a TWG member in the Peterborough to Kingston region resulted in advance information collection on emerging needs in the region, which helped deliver a timely and quality report during the NA phase. The figures below show in detail how the pre-Regional Planning steps are integrated into the NA and RIP phases.

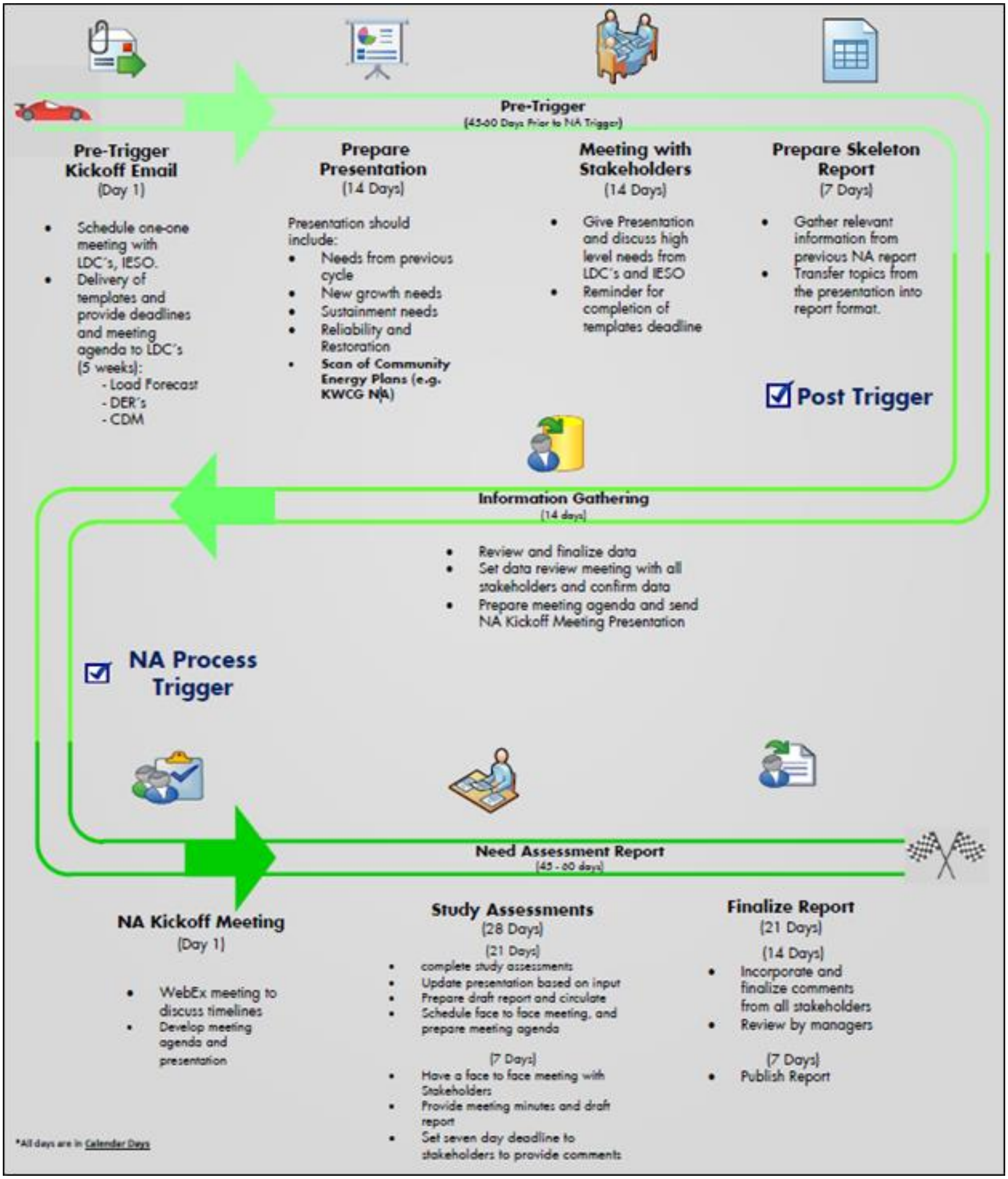


Figure 3-1. Needs Assessment (NA) Phase Diagram

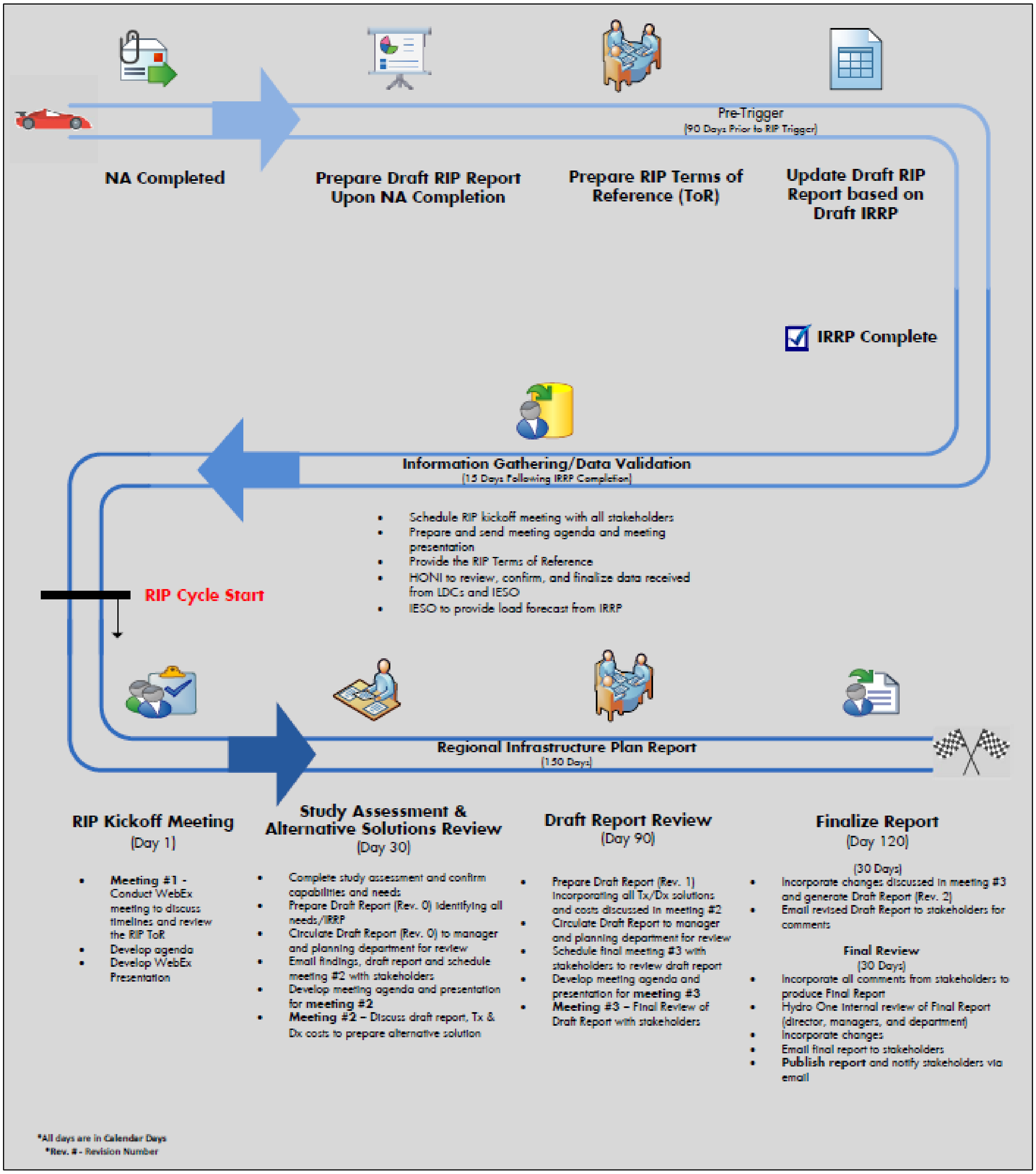


Figure 3-2. Regional Infrastructure Planning (RIP) Phase Diagram

4. STATUS OF REGIONS

Regional Infrastructure Plans (RIP) have been completed for all regions for the first cycle of the Regional Planning Process. For the second regional planning cycle, Hydro One has completed Needs Assessment reports for all twenty (20) regions where Hydro One is the lead transmitter as well as RIP reports for fifteen (15) regions with the five (5) remaining regions expected to be initiated in Q4 2022/Q1 2023, following the completion of their respective IRRPs. In addition, IESO has completed SAs for sixteen (16) regions and IRRP reports for eleven (11) regions with four (4) IRRPs currently underway. Hydro One has also initiated the third regional planning cycle with one (1) NA completed and three (3) NA's underway. These reports are available on the Hydro One's Regional Planning website.

At this time, no significant changes to the prioritization to initiate the third regional planning cycle have been proposed except for one region (Greater Ottawa). That said, Hydro One is keeping abreast of the needs in the province on a regional basis and will advance regional planning for regions as necessary based on emerging needs in the area.

4.1 Burlington to Nanticoke

Burlington to Nanticoke Region comprises the municipalities of Burlington, Hamilton, Oakville, Brantford, and the Counties of Brant, Haldimand, and Norfolk. The second regional planning cycle was completed with publishing of the RIP report in October 2019.The third regional planning cycle for this region was kicked off in April 2022 beginning with the Needs Assessment and was completed in September 2022. This is the first NA document to include sensitivity analysis 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. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- Cumberland TS: Power factor correction (completed in 2019).
- 115 kV B3/B4: Refurbishment of line section from Horning Mountain Jct. to Glanford Jct (completed in 2020).
- Elgin TS: Transformers & switchgear requiring replacement (replaced two DESNs with a single DESN in 2020/2021).
- Newton TS: Transformers (T1/T2) requiring replacement (completed in 2020).
- Kenilworth TS: Transformer & switchgear requiring replacement (replaced two DESNs with a single DESN, completed in 2021).

Needs and Plans underway in Burlington to Nanticoke Region:

- **Norfolk Area Supply Capacity**
  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. Upgrade of Jarvis TS and building feeders to pick up Norfolk area loads is planned for 2027-32 timeframe.

- **Refurbishment of 115 kV B7/B8 line section**
  The 115kV double circuit line B7/B8 supplies around 130 MW to Burlington and Oakville area loads through Bronte TS. The line section from Burlington TS to Nelson junction (approximately 2.3 km) was built in 1920's and based on asset condition assessment it requires replacement. This project is expected to be in-service by Q4 2024.

- **Refurbishment of Gage TS (T3/T4 and T5/T6 DESNs)**
  The TWG recommends Hydro One to reconfigure the station and reduce it from 3 DESNs to 2 DESNs due to poor condition of the existing transformers. Under this plan, the two DESNs, T3/T4 and T5/T6 made up of 56 MVA transformers, will be replaced by a single T10/T11 DESN with two 100 MVA standard units. The switchgear currently supplied by T5/T6 transformers will also be replaced. This project is expected to be in service by Q4 2023.

- **Load Transfer from Dundas TS to Dundas TS #2**
  Dundas TS has two DESNs; one of the two DESNs has loads more than its supply capacity while the other DESN has spare capacity to accommodate these excess loads. Hydro One Distribution is currently planning to build feeders required for load transfers from Dundas TS to Dundas TS #2 by 2023. No new additional work inside Dundas TS #2 is required for these load transfers. The combined supply capacity of both Dundas TS DESNs is sufficient over and beyond the study period.

- **Power Factor Correction at Kenilworth TS**
  At Kenilworth TS the historical loading data indicated that under peak load the power factor is lagging below the ORTAC[5] requirement of 0.9. To address this issue the TWG recommended the installation of a capacitor bank and/or for Alectra Utilities to work with load customers supplied by Kenilworth TS to meet ORTAC[5] 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.

- **Refurbishment of 115 kV breakers at Newton TS**
  To maintain system reliability and based on asset condition assessment Hydro One has identified an asset replacement need for 115 kV breakers at Newton TS with a planned in-service of 2025.

- **Brant Area Supply**
  The 115 kV Brant area is supplied by two stations, Brant TS and Powerline MTS. A Brant Subregion IRRP was completed by the IESO in 2015 to address 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. The 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 next phases of third regional planning cycle.

- **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. The TWG recommends that Hydro One monitor the loading levels of Norfolk area supply system and take remedial measures if required. This need will be reviewed during the next phases of the third regional planning cycle.

- **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. 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 well below their supply capacities. This need will be reviewed during the next phases of the third regional planning cycle.

- **Caledonia TS Capacity**
  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 the normal growth load forecast scenario. The TWG recommended Hydro One to monitor the loading at Caledonia TS and this need will be reviewed during the next phases of the third regional planning cycle.

- **Nebo TS Capacity**
  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 next phases of the third regional planning cycle.

- **Mohawk TS Capacity**
  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 next phases of the third regional planning cycle.

4.2 Toronto

The Toronto (formerly referred to as Metro Toronto) Region comprises the area within the municipal boundary of the City of Toronto. In the first regional planning cycle, the region was divided into two sub-regions: Central Toronto and Northern Toronto sub-regions. In the second Regional Planning cycle, the Toronto Region was assessed as a whole, and no sub-regions were created.

The second regional planning cycle RIP was completed in March 2020. The third regional planning cycle for this region was initiated in August 2022 beginning with the Needs Assessment and is currently underway. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- Midtown Transmission Reinforcement Project (completed in 2016)
- Clare R. Copeland 115 kV Switching Station and Copeland MTS (completed in 2019)
- West Toronto Area Station and line Capacity (added new DESN at Runnymede TS site and upgraded K1W/ K3W/ K11W/ K12W 115kV circuits, completed in 2018)
- Manby SPS Load Rejection (L/R) Scheme (completed in 2019)
- Southwest Toronto Station Capacity (added new DESN at Horner TS, completed in 2022)

Needs and Plans underway in Toronto Region:

- **Downtown District Station Capacity (Copeland MTS)**
  Phase 1 has been in service since Q1 2019. Phase 2 of the project includes adding a second 115/13.8kV DESN at the Copeland MTS site. Based on the station capacity consideration for the Downtown District stations, Phase 2 is expected to be completed by 2023.

- **Richview TS to Manby TS Corridor Reinforcement**
  The Toronto IRRP reconfirmed the capacity need of this corridor based on the changes in assumptions and the up-to-date load forecast. The recommended plan is staged as follows:

  Stage 1: Rebuild existing 115kV idle line to 230kV 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 “super circuits”. Stage 1 is currently expected to be in-service in 2026.

  Stage 2: Unbundle the super circuits. At Richview TS, the new circuits will be tapped to existing 230 kV circuits V73R and V79R from Claireville TS. The work is planned to be completed coincident with Manby TS EOL refurbishment work, which is planned for completion by 2032.

- **East Harbor / Port Lands Area Transformation Capacity**
  The LDC has identified an emerging area of load growth in the East Harbor and Port Lands in Toronto. The current load in the area is supplied from Esplanade TS and Basin TS. Transformation capacity in the area is sufficient with present day loading; however, due to the potential growth in area load, there may be a need for increased capacity around 2030+. This need will be further assessed in the next regional planning cycle to review options and to develop a preferred plan.

- **Load Restoration – C14L+C17L, C5E+C7E, and K3W+K1W**
  For the loss of circuits, C14L+C17L, C5E+C7E, and K3W+K1W, the load interrupted by configuration can exceed 150 MW and/or 250 MW and are required to be restored within the prescribed timelines as described in the ORTAC[5]. This need has been assessed in the IRRP phase, which determined that there is sufficient low voltage load transfer and switching capabilities to meet the load restoration requirements.

- **Main TS T3/T4 Transformer Replacement**
  The TWG recommends that the existing 45/75 MVA transformers be replaced by larger 60/100 MVA transformer units, given the longer-term potential of load growth and additional system resiliency and flexibility provided. The replacement is expected to be completed by the end of 2024.

- **Bermondsey TS T3/T4 Transformer Refurbishment**
  The TWG recommends that Hydro One proceed with the refurbishment of the T3/T4 DESN of Bermondsey TS as per current standard. The refurbishment is expected to be completed by 2028.

- **John TS – Transformers, 115 kV breakers, and LV Switchgear Replacement**
  The TWG recommended the replacement of T2, T3, T5, T6 transformers with 60/100 MVA units in a similar connection arrangement as the most feasible and economic solution. Existing oil filled breakers will be replaced with SF6 breakers. The transformers and breakers replacement will be coordinated with Toronto Hydro's work to replace their LV switchgear in several stages. Transformers T1, T2, and T4 have already been replaced (completed in 2019 to 2021) and T5 and T6 are planned for replacement in 2025. Transformer T3 and all associated HV breakers were found to be in fair condition and the timing to replace them is deferred.

- **Manby TS – Replacement of T7, T9, T12 Autotransformers, T13 Step-down Transformer and Rebuild 230kV Yard**
  The TWG recommends replacement of Manby East T7, T9, and Manby West T12 autotransformers with 250 MVA units. Also, Manby T13 DESN transformer will be replaced with 75/93 MVA unit along with 230 kV oil breakers and modification of 230 kV switchyard. Three new breakers will be installed to accommodate the new circuits to Richview TS (as part of the Richview TS to Manby TS Corridor Reinforcement). The transformers are planned for replacement in 2029 and the 230kV oil breakers and yard modification are planned after 2030.

- **115kV C5E/C7E Underground Cable Esplanade TS to Terauley TS**
  The TWG recommends refurbishment of the cables with new 230kV rated cables, which have higher insulation and are less prone to failure. The project is expected to be completed by 2026.

- **115 kV Overhead Line H1L/H3L/H6LC/H8LC (Bloor St. JCT to Leaside JCT) Refurbishment**
  The TWG recommends the refurbishment of the overhead section as per current standard. This project is expected to be completed by 2027.

- **115kV L9C/L12C (Leaside TS to Balfour JCT) Refurbishment**
  The TWG recommends the refurbishment of the overhead section as per current standard. This project is expected to be completed by 2026.

The third regional planning cycle for this region was initiated in Aug. 2022 with the NA phase and is currently underway.

4.3 Windsor-Essex

The Windsor-Essex region includes the most southerly portion of Ontario, extending from Chatham southwest to Windsor. It consists of the City of Windsor, the Municipality of Leamington, the Town of Amherstberg, the Town of Essex, the Town of Kingsville, the Town of Lakeshore, the Town of LaSalle, the Town of Tecumseh, and the Township of Pelee, as well as the western portion of the Municipality of Chatham-Kent.

The second regional planning cycle was completed with publishing of the RIP report in March 2020. The third regional planning cycle for this region was initiated in October 2022 beginning with the Needs Assessment and is currently underway. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- Crawford TS transformer T3 replacement and neutral grounding reactors installation on T3 and T4 (I/S 2017)
- Malden TS breakers replacement (I/S 2018): replacement of two 27.6 kV feeder breakers
- Supply to Essex County Transmission Reinforcement (I/S 2017): Build new 13 km double-circuit 230 kV transmission lines to Leamington area tapped to existing C21J/C22J circuits, and new 75/100/125 MVA Leamington TS and its distribution feeders.
- Reconfiguration of 230 kV and 115 kV circuits and 27.6 kV feeders at Keith TS to accommodate the construction of Gordie Howe International Bridge (I/S 2019)
- Leamington TS expansion: Build the second 75/100/125 MVA DESN at Leamington TS (I/S 2019)
- Kingsville TS transformers replacement: Transformers T2 and T4 replacement with 50/83 MVA T6 (completed in 2018). Transformers T1 and T3 replacement with 50/83 MVA T5 (completed in 2022).
- South Middle Road TS: Build two new DESNs (T3/T4 DESN completed in 2022; second DESN expected I/S 2025)
- Lakeshore TS: Build new switching station at Leamington Junction (completed in 2022)

Needs and Plans underway in Windsor Essex Region:

- Keith TS autotransformers replacement (in progress, I/S 2023): 125 MVA autotransformers T11 and T12 will be replaced by 250 MVA units.
- Tilbury TS decommissioning (in progress, I/S 2024): Decommissioning of station due to end-of-life and transfer serviced load to Tilbury West DS supply.
- Keith TS transformer T1 decommissioning (expected I/S 2024).

- **J3E/J4E Load Restoration**
  It was identified that SECTR project might not fully address the load restoration challenges in the J3E/J4E sub-system following the loss of C23Z/C24Z. The TWG further assessed the load restoration need in IRRP phase and confirmed that existing transmission reconfiguration options are sufficient to restore the interrupted load. Hence, there are no additional load restoration requirements during the study period of the second regional planning cycle.

- **Keith TS T11/T12 Autotransformers Replacement**
  T11 and T12 are to be replaced with larger 250MVA units to improve load supply and restoration capability for the 115kV J3E/J4E subsystem. This work is currently planned to be completed by 2023.

- **Lauzon TS T5/T6 Transformer Replacement & 115kV Subsystem Supply Capacity**
  At Lauzon TS, there are two autotransformers T1/T2, and two DESNs – DESN #1 supplied by step-down transformers T5/T6, and DESN #2 supplied by step-down transformers T7/T8. T5 and T6 are currently planned for replacement with larger 125MVA units by 2026. Step-down transformers T7 and T8, and autotransformers T1 and T2 are expected to be replaced by 2029.

- **Tilbury TS Decommissioning**
  Decommissioning of Tilbury TS station and transfer serviced load to Tilbury West DS supply is in progress and it is expected to be completed by 2024.

- **Supply Capacity to Kingsville-Leamington Area**
  The TWG recommends building a new switching station at Leamington Junction (to be known as Lakeshore TS, two new DESNs at a station called South Middle Road TS (to be built in close proximity to Lakeshore TS), and building new 230 kV double-circuit transmission line between Chatham SS and the new Lakeshore TS. The Lakeshore TS and one DESN at South Middle Road TS were completed in 2022. The planned in-service date for the second DESN at South Middle Road TS and the new line between Chatham SS and the new Lakeshore TS is planned for 2025.

- **Kent TS Station Capacity**
  The TWG recommended to further evaluate this need as part of the Chatham-Kent/Lambton/Sarnia regional planning process. The TWG for the Chatham-Kent/Lambton/Sarnia RIP recommends a new station (proposed to be named Dresden TS) on the Lambton by Chatham corridor subject to the confirmation of the load materializing in the Dresden Area. Due to the existing limitations on the L28C/L29C circuits the construction of the new Dresden TS would be aligned with the construction of the new Lambton by Chatham transmission

line with the intention of being ready connect new customers at the same time that the new double-circuit line is planned for completion (2028). The immediate capacity needs of new customers can be supplied by the limited capacities available at Kent TS (T1/T2 DESN) and Wallaceburg TS until the proposed Dresden TS is placed in service. The need for Dresden TS may possibly be delayed if the Lambton by Chatham routing results in additional capacity becoming available at Wallaceburg TS.

- **Belle River TS Station Capacity**
  The TWG recommends monitoring load growth and re-evaluating the need in the next regional planning cycle.

The third regional planning cycle for this region was initiated in Oct. 2022 with the NA phase which is currently underway.

4.4 GTA North

The GTA North Region is approximately bounded by the Regional Municipality of York, and includes parts of the Cities of Toronto, Brampton, and Mississauga. The second regional planning cycle was completed with publishing of the RIP report in October 2020. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- Vaughan #4 MTS (completed in 2017)
- Holland breakers, disconnect switches and special protection scheme (completed in 2017)
- Inline switches on the Parkway Belt (V71P/V75P) at Grainger Jct. (completed in 2018)

Needs and Plans underway in GTA North Region:

- **Vaughan MTS Transformation Capacity**
  The TWG recommends building a new Vaughan #5 MTS by 2030 to address the need for additional transformation capacity for Vaughan area stations.

- **Markham MTS Transformation Capacity**
  In the first cycle RIP, the TWG recommended to continue the assessment of wires and non-wires options to address the need for additional transformation capacity in the Markham-Richmond Hill area and to refine the need timing. Based on the latest extreme summer weather non-coincident peak net load forecast, the need for additional transformation capacity is projected to be in 2025. The IESO issued a letter of support to Hydro One Transmission and Alectra to begin wires planning for a new 230/27.6kV DESN (Markham MTS#5). During the second cycle, the TWG recommended building the new station at Buttonville TS and connecting to the P45/P46 circuits. Alectra will be building the station and Hydro One will be building the line tap connection from P45/P46. The new Markham MTS#5 is expected to be built by 2025. and upgrading the supply capability of 230 kV circuits P45/P46 is expected to be completed by 2027.

- **Transmission Line Uprate – P45/P46**
  The connection of the new Markham MTS#5 to the Parkway TS x Buttonville TS P45/P46 circuits will increase the loading on these circuits. The transmission capacity is thermally limited by an approximately 1.1 km long section between Parkway TS and Markham #4 Jct. Loading is expected to exceed the rating by 2029. It is expected that the thermally limiting section of this line can be increased by changing the conductor to be capable of supplying the forecasted load on these circuits. It is also prudent to consider uprating these circuits before the need date to reduce the amount of load at risk during construction outages. Completing this upgrade in time for the Markham MTS#5 in service date will also allow for the LDC to make full use of this facility's capacity to manage distribution operations including restoration, optimizing feeder loading, and accommodating maintenance.

- **Station Service Supply to York Energy Centre**
  In the first cycle RIP, a need for addressing station service supply to York Energy Centre (currently supplied from Holland TS) in the event of a (i) low-voltage breaker failure at Holland TS; or (ii) double circuit 230 kV contingency, was identified. These events can result in an interruption to the station service supply to York Energy Centre and therefore the loss of all generation output until the station service can be restored from the alternate source. This need was reaffirmed in the second cycle and the TWG recommends that the IESO and Capital Power (York Energy Centre's operator and 50% owner) proceed to identify and consider options for a new station service supply arrangement. Any new configuration should allow for continuous York Energy Centre operation following the simultaneous loss of H82/83V (total loss of distribution supply from Holland TS) or the loss of B88H (loss of transmission supply point).

- **Northern York Area Transformation Capacity**
  The TWG identified the need for additional transformation capacity in the Northern York Area for the areas supplied by Armitage TS and Holland TS, along with associated transmission capacity. Based on the latest load forecast the transformer stations capability (Holland TS/Armitage TS) will be needed by 2027. It is anticipated that the new station will be supplied by circuits B88H/B89H which are in the vicinity of the forecasted load growth. The TWG recommends that further discussions between Hydro One and the LDCs take place to determine the final location and connection point to meet an in-service date of 2027.

- **Load Restoration for 230 kV Circuits V43/V44**
  V43 and V44 circuits supply Woodbridge TS, Vaughan #3 MTS, and Kleinburg TS. The need was identified in 2016 during the first cycle Needs Assessment for the GTA North – Western Sub-Region because the load restoration timelines as per the ORTAC[5] may not be met. During the second cycle, the TWG agreed that no further action is required at this time and the need be reviewed during the next regional planning cycle. The Kleinburg to Kirby option to address the supply capacity needs in the long term would improve the load restoration capability for these circuits. Based on the long term forecast the supply capacity needs will arise between 2030 and 2035. Until a preferred long-term solution is identified for the Claireville to Minden corridor, the TWG determined that there is no need to pursue other alternatives.

- **Improve Load Security on the Parkway to Claireville Line**
  The Parkway to Claireville line (V71P/V75P) is located on the Parkway Belt and supplies five load stations with a combined load of approximately 700 MW based on latest summer peak load conditions. The load security criteria in ORTAC[5] limits the amount of load that can be interrupted due to the loss of two elements (e.g.: a double circuit line outage) to 600 MW under peak load. On the Parkway to Claireville line, that limit is exceeded. The installation of inline switches on the V71P/V75P circuits at the Vaughan MTS #1 junction (completed in 2018) do not reduce the amount of load that is interrupted, however the project enables Hydro One to quickly isolate the problem and allow the resupply of load to occur expeditiously. The TWG recommends that no further action is required at this time since the switches permit quick restoration of the load.

- **Woodbridge TS Transformer T5 Replacement**
  Woodbridge TS supplies both Alectra and THESL. Woodbridge TS comprises one DESN unit, T3/T5 (75/125 MVA), with two secondary winding voltages at 44 kV and 28 kV. T5 has been identified to be in poor condition and requiring replacement. The TWG recommended to replace the transformer with a similar type and size unit as per current standard. Replacement will be led by Hydro One and coordinated with the affected LDCs and no further regional co-ordination is required. Currently, Transformer T5 is expected to be replaced in 2027.

- **High Voltages on M80B/M81B**
  Post-contingency voltages on M80B/M81B may exceed 250 kV during future high load conditions. High voltages at Beaverton TS and Lindsay TS may occur following contingencies that leave these stations radially connected to Minden TS. These high voltages are observed when low voltage capacitor banks at Beaverton TS and Lindsay TS are dispatched under heavy load. The TWG recommends switching LV caps manually at Beaverton TS and Lindsay TS to mitigate high voltages when required.

It is expected that the third regional planning cycle for this region will be initiated in 2023, beginning with the NA phase.

4.5 Greater Ottawa

Greater Ottawa Region covers the municipalities bordering the Ottawa River from Stewartville in the West to Hawkesbury in the East and North of Highway 43.
The second regional planning cycle was completed with publishing of the RIP report in December 2020. The third regional planning cycle for this region was initiated in August 2022 beginning with the Needs Assessment and is currently underway. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- King Edward TS station capacity (replaced with new Transformer T3 with higher capacity 60/100 MVA in 2021)
- Hawthorne TS exceeded LTR (replaced T7 & T8 transformers in 2019 and T5 & T6 in 2021 with higher rated 150 MVA transformers)
- A4K supply capacity (new A6R Tap project was completed in 2019).

- Cambrian MTS and South Nepean Transmission reinforcement: The section of S7M (single circuit 115 kV line) from Hunt Club road (STR673JCT) to Manotick JCT, and from Manotick JCT to Cambrian Road was rebuilt as a double circuit 230 kV line. At STR673JCT, the new double circuit connects both S7M (to continue the supply to the area stations) and to E34M to supply the new Cambrian MTS. The two circuits were extended for about 1.3km along Cambrian road to supply the new MTS. This project was completed in 2022.

Needs and Plans underway in Greater Ottawa Region:

- **Circuit L2M Supply Capacity**
  L2M is a 115 kV circuit supplying Limebank MTS and Marionville DS. The circuit is thermally limited to approximately 86 MW. Based on the study results, the 7.8km line section between Merivale TS and Limebank MTS is expected to reach its thermal capacity limit in the medium term by 2029. The TWG recommends monitoring the load at Limebank MTS and implement load transfers to Cambrian MTS when L2M reaches its thermal capacity. With the ongoing Gatineau Corridor EOL study, network changes could occur which would alleviate the thermal capacity need of L2M. This need will be re-evaluated in the next regional planning cycle when the Gatineau Corridor EOL study results are known.

- **Merivale TS T22 Transformation Capacity**
  The need for additional 230/115kV auto-transformation capacity at Merivale TS was assessed by the TWG. It is recommended to replace transformer T22 at Merivale TS with a like-for-like unit (in situ) by 2025 as a first step to address the need for increased supply to the 115 kV system. The on-going studies can impact this timing based on their recommendations and necessary approvals including SIA. The TWG recommends Hydro One monitor the health of all aging assets at the station and develop a plan to address both sustainment and development needs following completion of the studies.

- **Bilberry Creek TS Refurbishment**
  Bilberry Creek TS consists of a 115/27.6 kV step-down transformer in East Ottawa, supplying up to 85 MW of load to both Hydro Ottawa and Hydro One Distribution. The station was built in 1964 and a number of its key components have been identified for replacement by Hydro One. The TWG recommends that Hydro One proceed with the like-for-like refurbishment of Bilberry Creek TS (planned in-service date is 2028), with expansion to accommodate two additional breaker positions for Hydro Ottawa’s load transfers and possible growth in the area (planned in service date is 2024).

- **Hawkesbury MTS Capacity Upgrade**
  Hydro Hawkesbury is supplied from two transformer stations, Hawkesbury MTS and Longueuil TS. Currently Hawkesbury MTS has a 15 MVA transformers and a 7.5 MVA transformer to supply their load. Hydro Hawkesbury plans to replace their 7.5 MVA transformer with a new 15 MVA transformer. This is planned to be in service in 2026. This upgrade will increase the station capacity and improve customer reliability such that if a transformer must be taken out of service, the entire station load can be supplied without interruptions.

- **Lincoln Heights TS Transformer T1/T2 Replacement**

Lincoln Heights TS is an indoor DESN station housing two 40-45 years old 45/60/75 MVA transformers. The station is supplied by two 115 kV circuits F10MV and C7BM and supplies electricity to Hydro Ottawa customers. Since the existing transformers are at end of life, the TWG recommended for these transformers to be replaced with new standard 45/60/75 MVA units. These transformers are planned to be in service in 2023.

- **Russell TS T1/T2 and Component Replacement**
  Russell TS is supplied by two 115 kV circuits A5RK and A6R and supplies electricity to Hydro Ottawa customers. The two 45/60/75 MVA transformers T1 and T2 were installed in 1975 and 1971 respectively and they need to be replaced. The TWG suggested to replace these transformers with new standard 45/60/75 MVA or with 60/80/100 MVA units to optimize the LTR of the station following the studies and anticipated load at this station. The project is expected to in-service by late 2026.

- **Overbrook TS Station Capacity**
  Overbrook TS is 115/13.8 kV transformer station in east of the Ottawa downtown core. A review of the station's LTR indicate that the 13.8 kV cables from the transformers to the 13.8 kV switchgear are limiting the transformation capacity of the station. The TWG recommends that Hydro One to review the capacity of the 13.8 kV cables to determine the cause of the limitation in 2021. The findings will be discussed between Hydro One and Hydro Ottawa to determine next steps, which could include LV cable upgrades or implementation of new feeder ties to transfer load out of the station. The plan should be implemented by 2026 when station is expected to reach its capacity.

- **Hawthorne TS Station Capacity**
  The study group identified that the DESN station at Hawthorne TS will be overloaded in 2026 by approximately 2 MW and reaches 32 MW by the end of the study period. It is recommended to install a new station on circuit L24A to relieve the stations in the south area of any overloads, including Hawthorne TS. Once the new station on L24A is in service it will alleviate the overloading experienced at Hawthorne TS.

- **Orleans TS Station Capacity**
  Orleans TS was placed in service in 2015 that supplies Hydro One Distribution and Hydro Ottawa. Based on the forecast, the station's transformation capacity is expected to reach its limit in the near term and overloaded by approximately 15 MW within the next 10 years.
  Hydro One Distribution has confirmed that transfer capability is available to nearby stations Bilberry Creek TS, Wilhaven DS, and Navan DS. To accommodate Hydro Ottawa load transfers, two new feeder breakers may be required at Bilberry Creek TS by 2024. The TWG recommends managing any overload at Orleans TS by load transfers to neighboring stations.

- **Riverdale TS 13.8kV Switchgear Replacement**
  Riverdale TS is a 115/13.8kV station connected to 115kV circuits A3RM, A5RK, and A6R. Switchgears on Riverdale TS 13.8kV side have been identified approaching their end of service life. The TWG recommended that Hydro Ottawa continue with the 13.8kV switchgear replacement plan. The station is expected to be in-service by 2024.

- **Almonte TS/Terry Fox MTS Voltage Regulation**
  Circuit E34M/T33E is a 290 km line between Clarington TS in Oshawa, and Merivale TS in Ottawa. If the circuit E34M is open at the Merivale TS end, Terry Fox MTS and Almonte TS will need to be supplied radially by Clarington TS. However, studies have shown that Clarington TS will not be able to provide adequate support for Almonte TS and Terry Fox MTS during peak loading period, which would in turn result in voltages below the minimum allowable levels.
  Hydro Ottawa's new station, Cambrian MTS, will implement a scheme to remove the station load from circuit E34M and move it to its alternate supply S7M in the event of a line end open (LEO). A LEO at Merivale TS can results in load loss at Almonte TS and Terry Fox MTS. Terry Fox MTS is part of the Ottawa Area under voltage load rejection scheme ("UVLS"). This scheme is designed to shed the station load if the 230 kV supply voltage to the station drops below 204 kV when it is activated. The combined load of both stations is less than 150 MW and can be restored within 8 hours as mandated by the ORTAC[5]. As the load restoration criteria can be met, no further action is recommended by the TWG.

- **S7M 115kV Line Refurbishment**
  The 115 kV conductors, spread across multiple S7M line sections totaling 6.5 km, have been identified at or near their end of service life. As suggested by Hydro One, refurbishment of these line sections is recommended by the TWG, to replace conductors, wood poles, insulators, and other components. The refurbishment is expected to be completed in Q2 2023.

- **Albion TS – T1/T2, Switchgear and Circuit Breakers Replacement**
  Albion TS is a 230/13.8/13.8kV station connected to 230kV M30A and M31A circuits, supplying Hydro Ottawa. The existing transformers T1 and T2 are rated at 75MVA each, were built in the 1970s, and have been identified for replacement due to their poor condition. As per the recommendation from Needs Assessment and further assessed in the IRRP, Albion T1 and T2 are scheduled to be replaced with new closest standard size 60/80/100 MVA units. All existing Hydro One owned circuit breakers will be replaced with breakers of similar rating. This replacement project is scheduled to be in-service by late 2026. No increase in the transformation capacity is recommended.

- **M50A/M31A Circuit Upgrade**
  The 230 kV circuits M30A and M31A between Hawthorne TS and Merivale TS are scheduled to be replaced with twin-bundled conductors to increase the circuit ratings. This work is expected to increase the interface limit from 648 MW to 1080 MW and to be completed in 2024.

- **Slater TS Transformers T1/T2/T3 Replacement**
  Slater TS is an 115/13.8/13.8kV station connected to 115kV A3RM, M4G, and A5RK circuits, supplying Hydro Ottawa. The station has three transformers T1, T2, and T3, rated at approximately 65MVA each, built in the 1960s. In 2018, T1 failed and was replaced with a 100MVA unit. Currently Hydro One is in process of replacing and upsizing the remaining T2 and T3 with new 100MVA units. This additional LMC would provide Hydro Ottawa with flexibility to transfer load from other stations in the downtown Ottawa area, where there are limited options for siting new supply stations. The replacement of the equipment is expected to be completed by 2023.

- **Arnprior TS – Transformers T1/T2 Replacement and Rebuilding DESN**
  Arnprior TS is a 115/44 kV DESN connected to W6CS and C7BM 115 kV circuits, supplying Hydro One Distribution. Transformers T1 and T2, built in 1960 and 1957, respectively, rated at 42MVA each, have been identified to be at the end of life. The TWG recommended to replace these transformers with like-for-like units and build a new 44kV switchyard to supply the station load. The replacement of this equipment is expected to be completed by 2023.

- **Longueuil TS Transformers T3/T4 Replacement**
  Longueuil TS is a 230/44kV DESN connected to 230kV B5D and D5A circuits, supplying Hydro One Distribution. Transformers T3 and T4, built in 1965 and 1964, respectively, are rated at 93MVA each. The TWG recommended these transformers to be replaced with either new 83.3MVA or 125MVA units. Final coordination about the size of new transformers will be taken in coordination with Hydro One Distribution based on anticipated load at the station. The replacement of these equipment is expected to be completed by late 2024.

- **79M1 Circuit – Voltage Regulation**
  There is low voltage observed on this circuit and the voltage regulation is dependent on the amount of load being supplied by the circuit. In addition, it is impacted by load supplied by 115kV circuit H9A within the Ottawa Area sub-region. This voltage regulation is reviewed during the RIP phase and studied confirmed that the area and stations supplied by the 79M1 circuit is within the limits of ORTAC[5] for the near term. Hydro One continues to monitor the loading in the area and voltage on the line and if required this need to be reassessed in the next regional planning cycle.

The third regional planning cycle for this region was initiated in August 2022 with the NA phase which is currently underway.

4.6 Kitchener-Waterloo-Cambridge-Guelph (KWCG)

The KWCG region includes the municipalities of Kitchener, Waterloo, Cambridge, and Guelph, as well as portions of Perth and Wellington Counties and the Townships of Wellesley, Woolwich, Wilmot, and North Dumfries.

The second regional planning cycle was completed with publishing of the RIP report in December 2021. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- 115kV system supply capacity (GATR project): Two new 230/115kV autotransformers at Cedar TS to reinforce supply to both 115kV sub-systems in the region (completed in 2016).
- 230kV load restoration needs (GATR project): Two new 230 kV in-line switches on D6V/D7V circuits to improve restoration capability of Waterloo-Guelph 230 kV sub-system (completed in 2016). Also, two new 230kV in-line switches on M20D/M21D circuits to improve restoration capability of the Cambridge-Kitchener 230 kV sub-system (completed in 2017).
- Station short circuit (Arlen MTS): Install 13.8 kV series reactors to mitigate LV bus short circuit levels (LDC project, completed in 2016).
- Campbell TS: Replaced vintage T1 (completed in 2018) and T2 transformers (completed in 2019).

- Detweiler TS: Replaced 230 /115 kV Auto Transformers T2 (completed in 2020) and T4, AC station service and components (completed in 2021).
- Refurbished tower 157 near Freeport SS for D7F / D9F 115 kV (completed in 2020/2021).

Needs and Plans underway in KWCG Region:

- **Hanlon TS Transformers T1/T2 Replacement**
  Hanlon TS is located south of the city of Guelph supplying Alectra loads. Hanlon TS is a single T1/T2 DESN station of 33 MVA nonstandard transformers having a LTR of 48 MVA (43 MW @ 0.9 PF). This station is currently supplying about 27.5 MW of peak load. The T1/T2 transformers were built in 1955-56 and in poor condition requiring replacement. The TWG recommended Hydro One to replace these transformers with standard size of 42 MVA units. These transformers are planned to be in service in 2022-2023.

- **Kitchener MTS#5 Transformers T9/T10 Replacement**
  Kitchener MTS #5 is in the city of Kitchener supplying Kitchener-Wilmot Hydro Inc. loads. The existing 83MVA nonstandard transformers T9 and T10 are supplying 67 MW of peak load. The loads at Kitchener MTS #5 are currently forecasted to grow at about 15% over the entire study period and approaches the supply capacity of this station by 2028. The T9/T10 transformers at this station have been identified as approaching end of life requiring replacement. The TWG recommends replacing the T9/T10 with standard units of similar or greater size, that can provide higher LTR for station capacity to be sufficient beyond study period. Kitchener-Wilmot Hydro Inc. and Hydro One will coordinate the replacement plan of these transformers. This investment is expected to be completed by 2023-2024.

- **Scheifele MTS Transformers T1/T2 Replacement**
  Scheifele MTS is in the city of Waterloo supplying Waterloo North Hydro Inc. loads. Scheifele MTS has four 230/13.8 kV transformers T1 and T2 of 69 MVA, and T3 and T4 of 110 MVA supplying 145 MW of peak loads. The total supply capacity of Scheifele MTS is 161 MW expected to be sufficient over the study period, except marginal overloading in 2041. The T1/T2 are approaching end of life and required to be replaced by 2025-2026. The TWG recommends that Waterloo North Hydro continue monitoring the condition of these T1/T2 transformers at Scheifele MTS and if required, proceed with replacement plan otherwise this need may be reassessed in the next regional planning cycle.

- **B5C/B6C Circuit Refurbishment**
  The 115 kV B5C/B6C circuits consist of about 45 km of double circuit line and 15 km of single circuit line supplying South-Central Guelph 115 kV loads. About 12 km of double circuit line section from Burlington TS to Harper's Jct. and 15 km B5C 115 kV line tap from Harper's Jct. to a Westover Jct. require refurbishment. The refurbishment of the 27 km 115 kV B5C/B6C line sections from Burlington TS to a CTS is currently under execution and the work is planned to be completed by the end of year 2025.

- **Preston TS Transformers T3/T4 Replacement**
  Preston TS is in the city of Cambridge supplying Energy+ loads and contains two 125MVA transformers, T3/T4. The T3/T4 transformers are almost 50 years old and are in poor condition requiring replacement. This station is currently supplying about 92 MW of peak load. The loads at Preston TS are currently forecasted to peak at about 120 MW during the study period. The TWG recommends replacing the existing 125 MVA T3/T4 transformers with 125 MVA standard units. The project is expected to be completed by 2026-2027.

- **Cedar TS Transformers T7/T8 Replacement**
  Cedar TS is in the city of Guelph supplying Alectra loads and has two 115/13.8 kV DESN units T1/T2 and T7/T8 of 75 MVA with a LTR of 115 MVA and 37 MVA with a LTR of 44 MVA supplying 67 MW and 36 MW of peak loads respectively. The T7/T8 DESN 38 MVA nonstandard transformers were built in 1958 and have been identified for replacement due to poor condition. The T1/T2 transformers were built in early 1990s. The station cannot be downsized or eliminated because there is no nearby supply station/s to Cedar TS having surplus capacity where this station's loads can be transferred therefore the TWG recommends replacing these nonstandard transformers with standard units of 42 MVA in 2026-2027.

- **Fergus TS Transformers T3/T4 Replacement**
  Fergus TS is in the township of Fergus and has two 125MVA transformers T3 and T4 supplying 90 MW of peak loads. The total supply capacity of Fergus TS is 154 MW expected to be more than adequate over the study period. Condition assessment has identified that both 50 years old T3/T4 transformers as well as the feeder breakers are at their EOL requiring replacement. The TWG recommends that Hydro One continue monitoring the condition of these T3/T4 transformers and other components at Fergus TS and if required proceed with the replacement plan by 2028-2029 or otherwise this need may be reassessed in the next regional planning cycle.

- **Galt TS Breakers and Component Replacement**
  Galt TS is in the city of Cambridge supplying Energy + loads in the KWCG region and has two 230/ 125MVA transformers, T7 and T8, supplying 112 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 are new but the breakers and other component at the station are almost 50 years old. Condition assessment has identified that these components are at EOL, requiring replacement. The TWG recommends that Hydro One continue monitoring the condition of these EOL components at Galt TS and if required proceed with the replacement plan by 2028-2029 or otherwise this need may be reassessed in the next regional planning cycle.

- **Campbell TS Breakers and Component Replacement**
  Campbell TS is in the city of Guelph supplying Alectra loads. Campbell TS has four 100 MVA transformers, T1/T2 and T3/T4. Campbell TS is supplying about 89 MW and 47 MW loads via its two DESNs. Two feeder breakers and a tie breaker for T1/T2 DESN are in poor condition and requires replacement. The TWG recommends implementing replacement plan by 2028-2029.

It is expected that the next planning cycle for this region will be initiated in 2023 or earlier, beginning with the NA phase.

4.7 GTA West

The GTA West Region covers the Regional Municipalities of Halton and Peel, and comprises the municipalities of Brampton, South Caledon, Halton Hills, Mississauga, Milton, Oakville and parts of Burlington.

The second regional planning cycle was completed with publishing of the RIP report in February 2022. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- Halton Hills Hydro MTS (completed in 2018)
- Tremaine TS: Add 4 x 27.6 kV feeders (completed in 2020)

Needs and Plans currently underway in GTA West Region:

- **Palermo TS T3/T4 Replacement**
  The TWG identified a need for additional transformation capacity at Palermo TS. The peak station demand was about 124 MW in summer 2021 as compared to the station 10-day LTR of 110 MW. The T3/T4 transformers at Palermo TS are also in poor condition and require replacement. The transformers are planned for replacement by Q4 2026. The earlier NA and IRRP reports had identified the need for adding a second DESN at Halton TS by 2022 and that the capacity on Tremaine TS would be exceeded by 2033. The IRRP had also identified upsizing the Palermo TS transformers as a more cost-effective alternative to replacing the transformers like- for-like. During the second cycle RIP, Milton Hydro reviewed their load forecast and now plan to utilize the increased capacity at Palermo TS, thereby deferring the need for a second DESN at Halton TS to 2033. The Palermo TS upgrade also defers the need for providing relief for Tremaine TS to 2039. The TWG recommends that Palermo TS T3/T4 transformers be replaced with larger size 230/27.6kV, 75/125MVA units as it provides capacity to meet future load growth, removes the restriction on DER to connect to the station, maintains reliable supply to the customers in the area while increasing system resiliency and flexibility.

- **Station Capacity – DESN stations exceeding LTR**
  The TWG reviewed the step-down transformation capacity for the stations within the GTA West Region. The NA and IRRP studies had previously indicated that a second Halton TS DESN would be required by summer 2022. Subsequent to those studies, and as part of the discussions for second cycle RIP, Milton Hydro provided a revised load forecast with new load being supplied from Glenorchy MTS #1, Halton Hills MTS, and Palermo TS. As a result of this update, the need for the second Halton TS DESN has been deferred to 2033. The loading on the DESN stations – Erindale TS T1/T2, Pleasant TS T1/T2, Cardiff TS T1/T2, Erindale T5/T6 - is expected to exceed their station LTR during the 2021-2031 study period.
  The capacity need for Erindale TS T1/T2 was addressed in the 2019 GTA West Region NA Report where the TWG recommended that the need be managed by Alectra and no transmission upgrades are required. The loading issues at the Pleasant TS T1/T2, Cardiff TS T1/T2, and the Erindale TS T5/T6 are similar to those of Erindale T1/T2. The TWG recommends that these

loading issues be managed at the distribution level in the near term and review the station loadings again in the next regional planning cycle.

- **H29/H30 Transmission Circuit Supply**
  The TWG identified a thermal capacity need for circuits H29/H30 in the medium-term and recommended that the line conductor be upgraded. Hydro One is planning to replace the existing conductor with a higher ampacity conductor to reinforce the supply to Pleasant TS by Q2 2027.

- **Section of R19TH/R21H Overloaded**
  The loads at Jim Yarrow MTS and Pleasant TS are supported by the 230 kV line V41H/V42H from Claireville and the R19TH/R21TH line. Under certain outage conditions all loads at Pleasant TS and half the load on Jim Yarrow MTS can end up on one of the R19TH or the R21TH section between Hanlan Jct. and Hurontario SS. The IRRP had considered a number of alternatives to address this issue ranging from a local load rejection scheme at Pleasant TS to reinforcing the supply to Hurontario SS. Given that the possibility of the overlapping outages is rare, manual operator action can be taken to relieve the line overloads and will be adequate over the near to medium-term (till 2030). Hydro One has implemented an operating procedure under which Jim Yarrow MTS load is transferred to R21TH if V41H or H30 are out of service pre-contingency and to R19TH if V42H or H29 are out of service pre-contingency. The TWG recommends that the loading on the R19TH/R21TH and the performance of the manual scheme be monitored. The timing (currently forecast to be around 2030) and the preferred option for the LR scheme will be reviewed in the next planning cycle.

- **Load Security – 230kV circuits T38B/T39B**
  Due to the lower than expected load at Halton TS and Milton Hydro supplying some of the projected area load from the upsized Palermo TS, the loads connected to the 230 kV circuits T38B/T39B are not expected to exceed the 600 MW ORTAC[5] supply security limit until summer 2030. As such the TWG recommends that Hydro One continue to monitor the load and that the need be reviewed in the next regional planning cycle.

- **Load Restoration**
  The TWG identified that there are a number of lines that do not meet the IESO criteria of the restoration of all load above 250 MW in 30 minutes. However, given the high cost for mitigation measures, the low probability of the event happening and the ability to restore load within 4 hours, the TWG agreed that no further action is required.

- **Richview X Trafalgar Transmission Circuit Capacity**
  Loading limitations on 230 kV circuits between Richview TS and Trafalgar TS was assessed as part of the IESO-led Bulk System Planning study. The work is underway on reconductoring these circuits with new conductors and is planned to be in-service by Q2 2026.

- **Northwest Greater Toronto Area (NWGTA) Electricity Corridor**
  In February 2018, the IESO and the Ministry of Transportation have announced a joint corridor identification study on a proposed land corridor in the Northwest Greater Toronto Area (NW GTA). The purpose of this study was to identify land to be protected for future multi-purpose linear infrastructure (such as transmission lines and transportation infrastructure) to ensure it

can be accommodated when the need arises. The Ministry of Energy and the IESO have been working on the proposal to identify and protect a corridor of land for the future transmission corridor. The TWG supports the initiative for the development of the new corridor as it will be essential to meet the future area growth. The progress of corridor development will be reviewed in the next regional planning cycle.

- **Asset Replacement for Major HV Transmission Equipment**
  Hydro One has identified the need for replacement of major HV transmission assets over the next ten years at a number of GTA West Region Hydro One stations including Bramalea TS, Tomken TS and Lorne Park TS. The TWG recommendations for asset replacement plans have taken "right sizing" into consideration. At Bramalea TS the TWG recommends replacement of the 230/44kV, 50/83MVA transformers, T3 and T4 with larger size 230/44kV, 75/125MVA units (planned in-service date is 2028). At Tomken TS the TWG recommends like-for-like replacement of 230/44kV, 75/125 MVA transformers T1 and T2 (planned in-service date is 2029). Finally, at Lorne Park TS the TWG recommends like-for-like replacement of 230/27.6kV, 50/83MVA transformer T2 (planned in-service date is 2030).

It is expected that the next planning cycle for this region will be initiated in 2024 or earlier, beginning with the NA phase.

4.8 Greater Bruce/Huron

The Greater Bruce/Huron area is located to the west of the Kitchener-Waterloo region in southwestern Ontario. The region includes the municipalities of Arran–Elderslie, Brockton, Kincardine, Northern Bruce Peninsula and South Bruce. It also includes the township of Huron-Kinloss. With increased load requests in the region, the second regional planning cycle was triggered in early 2019.

The second cycle RIP report was completed in April 2022. Updates to the needs and plans recommended in this region are provided below:

Projects completed include:

- Centralia TS: Replaced three (3) existing transformers with two (2) 25/42 MVA transformer arrangement and other associated equipment (completed in 2019).
- Detweiler TS: Replaced T2 and T4 autotransformers and other associated equipment (completed in 2021).
- Stratford TS: Replaced T1 transformer and other associated equipment (completed in 2021).

Needs and Plans underway in Greater Bruce/Huron Region:

- **115kV L7S Circuit Capacity Increase**
  L7S is a single 115 kV circuit transmission line operated radial from Seaforth TS to St. Mary's TS, suppling municipalities of Bluewater, South Huron, Lambton Shores, Lucan Biddulph, Middlesex Centre, North Middlesex, Thames Centre, Zorra, Perth South, Town of St. Mary's, and West Perth. No capacity needs were identified during the study period, however, the recent connection

requests at Grand Bend East DS have triggered a re-assessment of the L7S section between Seaforth TS and Kirkton JCT to address the sub-standard clearances that are limiting the circuit's capacity. The TWG recommends that Hydro One proceed with the re-assessment of the limiting section of L7S, to increase the limiting spans' sag temperature from 83°C to 125°C. Addressing these sub-standard clearances will result in an L7S capacity increase of more than 10 MW. Strengthening L7S will be sufficient for supplying load connected to L7S load for the study period and into the long-term.

- **Customer Delivery Point Performance of L7S circuit**
  The performance of delivery points supplied from circuit L7S, specifically Centralia TS, Grand Bend East DS, St. Mary's TS and the 4 industrial customer connections, were reviewed. In 2021, remotely operated switches were installed at three locations on the L7S circuit, at Kirkton JCT, Biddulph JCT, and St. Mary's TS. These switches will reduce the outage duration and improve restoration by quickly isolating the problematic sections while resupplying the healthy sections of the line. Hydro One's line sustainment and wood pole replacement programs will continue to assess the condition of this circuit to determine where deteriorating components exist and refurbish the sections of concern to improve the integrity of the circuit. Hydro One will continue to monitor the delivery point performance to determine whether further improvement is required.

- **Seaforth TS T5/T6/T1/T2 and Component Replacement**
  Seaforth TS consists of two 150/200/250 MVA autotransformers supplied by 230 kV circuits B22D and B23D. The 115 kV yard from Seaforth TS supplies nearly 200 km of single circuit supply along the circuits L7S and 61M18. Seaforth TS also consists of two 25/33/42 MVA transformers and supplies Hydro One Distribution and embedded LDCs. The TWG recommended to replace autotransformers T5, T6, transformers T1, T2, the capacitor breaker and several HV and LV switches that are at EOL. The planned in-service date for the project is 2024.

- **Hanover TS T2 and Component Replacement**
  Hanover TS consists of two 75/100/125 MVA autotransformers supplied by 230 kV circuits B4V and B5V. The 115 kV yard has connectivity to Detweiler TS via 115 kV transmission circuit D10H with a normally open point at Palmerston TS. Another 115 kV transmission circuit S1H connects to Owen Sound TS. Hanover TS also consists of two, 50/67/83 MVA transformers supplying Hydro One Distribution and embedded LDCs. The scope of this project includes the replacement of 230 kV motorized switches, step-down transformer T2 and associated equipment, 115 kV motorized switches, surge arrestors, auto-ground switches, and potential transformers. This work was planned to be completed in 2028, however due to a recent transformer tap changer failure, T2 and its associated transformer switch are being replaced immediately and are expected in-service by the end of 2022. The remaining component replacements that were planned as part of the T2 work will be bundled with the replacement of T1 and have an expected in-service date of 2031.

- **Wingham TS T1/T2 and Component Replacement**
  Wingham TS was built in 1965. This station has two 50/67/83 MVA transformers connected to the 230 kV circuits B22D and B23D and supplies Hydro One Distribution. Based on asset condition assessment, the current scope of this project is to replace transformers T1 and T2 and associated

surge arrestors. Based on the load forecast, similar equipment ratings are required for the EOL replacement. This project is underway and the planned in-service date is 2023.

- **Other Asset Replacements of Major HV Transmission Equipment**
  Hydro One has identified the need for replacement of major HV transmission assets over the next ten years at a number of Greater Bruce/Huron stations as shown below. The TWG recommendations for asset replacement plans have taken “right sizing” into consideration.
  - **Bruce A TS:** Replacement of 230 kV circuit breakers and switches, uprating of station strain buses and protection & control relay building (planned in-service date is 2030).
    Replacement of 500 kV circuit breakers and switches, 2 500/230 kV autotransformers and upgrading of protection & control equipment (planned in-service date is 2027)
  - **Bruce B SS:** Replacement of 500 kV circuit breakers and switches (planned in-service date is 2024)
  - **Bruce HWP B TS:** Replacement of T7/T8 transformers and associated switches, replacement of low voltage transformer breakers & replacement of Protection and Control systems (planned in-service date is 2028)
  - **Douglas Point TS:** Replacement of T3/T4 transformers and associated switches, low voltage circuit breakers & switches and Protection & Control systems (planned in-service date is 2028)
  - **Owen Sound TS:** Replacement of T4/T5 transformers and associated switches, low voltage circuit breakers, switches, and Protection & Control systems (planned in-service date is 2028)
    Replacement of T3 transformer and associated switches & replacement of low voltage transformer breaker (planned in-service date is 2031)

It is expected that the next planning cycle for this region will be initiated in 2024 or earlier, beginning with the NA phase.

4.9 East Lake Superior

Hydro One has completed the acquisition of transmission assets from the former Great Lake Power Transmission on Oct 31, 2016 under the new name Hydro One Sault Ste. Marie, and therefore became the lead transmitter in the East Lake Superior (ELS) Region. The ELS Region includes all of Hydro One Sault Ste. Marie’s 560km of high-voltage transmission lines as well as ties to the rest of the provincial grid at Wawa TS in the northwest and Mississagi TS in the northeast. The region also includes Hydro One's 115kV W2C circuit supplying the Town of Chapleau from Wawa TS.

The second regional planning cycle was completed with publishing of the RIP report in October 2021. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- Wood Pole Replacements:
  Multiple wood pole replacement projects were completed on a number of 115kV and 230kV circuits. These circuits consisted of wood pole structures that were assessed at being at their end

of life and in need of replacements. The following circuits have their end of life wood pole structures replacement completed between 2014 to 2019:
  - No.2 and No.3 Algoma (completed in 2014)
  - Northern Ave 115kV circuit (completed in 2014)
  - No.1 Gartshore (completed in 2015)
  - Hogg (completed in 2015)
  - P21G (completed in 2019)
- Hwy 101 TS: Installed a new control building completed with new protection relays, batteries, chargers, automatic transfer schemes and RTU to replace components such as electro-mechanical relays and batteries (completed in 2015).
- Anjigami TS: Performed electrical and civil upgrade, including the installation of a new 44kV breaker, redundant battery and chargers, and replacement of protection equipment and other outdated AC/DC system. It also includes ground grid improvements (completed in 2017).
- Third Line Instantaneous Load Rejection Scheme: Eliminated/Minimized manual communication between IESO and OGCC by enabling remote arming of Third Line Instantaneous Load Rejection Scheme via ICCP line between IESO's EMS and HONI's NMS (completed in 2021).

Needs and Plans underway in East Lake Superior Region:

- **Third Line TS Protection Replacement**

  Third Line TS is a major transformer station in the region and it consists of two (2) 230/115kV, 150/200/250MVA autotransformers supplied by 230kV circuits K24G, P21G and P22G. Based on an asset condition assessment, P21G's and P22G's line protections are approaching end of life. Further, due to legacy reasons, P21G's and P22G's line protection do not meet standard physical separation requirement. It is recommended that the existing end-of-life protection will be replaced with new protection relay consistent with Hydro One standard. This alternative will also implement 'A' and 'B' protection separation, which will bring these protection be in compliance with reliability standards, addresses the end-of-life assets need, minimizes losses and maintains reliable supply to the customers in the area and expected to be completed by 2024.

  Among the 2 autotransformers, T2 is at end of life based on asset condition assessment. Based on long term load forecast, units with similar ratings are required for the end of life autotransformer T2 replacement. It is recommended to replace T2 with a unit that has equivalent rating and is expected to be completed by 2025.

- **Patrick St. TS 115kV Breaker Replacement**

  Patrick St. TS is an 115kV switching station that consists of thirteen (13) 115kV breakers. It connects to Third Line TS – 115kV station yard via 115kV Algoma No. 1, No. 2, and No. 3 circuits. It also connects to Clergue TS via 115kV Clergue No. 1 and No. 2 circuits. The station supplies major industrial customers in the Sault Ste. Marie area. Based on IESO IRRP findings, upon a breaker failure of breaker 214, or a contingency on either Algoma No.2 or Algoma No.3 circuit, followed by another contingency on the remaining circuit, Algoma No.1 will be overloaded beyond its short term emergency (STE) rating during peak load. At present, a manual load shedding scheme is implemented as an interim solution until a more permanent solution is available. It is recommended to implement automatic load rejection upon the loss of Algoma No. 2 and Algoma

No. 3 to reject load blocks and respect the existing long term emergency (LTE) rating of Algoma No. 1 circuit (to be completed in 2023). Based on asset condition assessment, breakers 208, 211, 214 and 217 are minimum oil live tank breakers require replacement. The TWG recommends replacing the breakers as it addresses the end-of-life asset needs and maintains reliable supply to customers connected at Patrick St TS by reducing the risk of breaker failure and reducing on-going maintenance costs associated with obsolete breaker technology. The project is expected to be completed by 2024.

- **Echo River TS – Transmission Supply Reliability and Breaker Replacement**
  Echo River TS is a 230kV load supply station. The station consists of a single 230/115/34.5kV autotransformer and a single 230kV circuit breaker (556) to supply two (2) 34.5 kV customer feeders. Historically, load at Echo River TS can be transferred to Northern Ave TS 34.5 kV feeders via the API's distribution system in case of outages at Echo River TS, such as transformer maintenance or failure. It has been identified that the existing back up from Northern Ave TS can no longer provide adequate voltage support at peak load during a transformer outage at Echo River TS. The TWG recommends installing "Hot" spare 230kV transformer and replacing end-of-life 230kV breaker. The spare transformer is planned for replacement by 2023, while the breaker replacement work is planned for completion in 2024.

- **115kV Sault No.3 Structure and Conductor Replacement**
  Built in 1929, Sault No.3 is a 90 km long 115kV transmission circuit that runs from MacKay TS 115kV station yard to Third Line TS 115kV station yard. This circuit provides an alternative path for local generation to reach load centers close to the Sault Ste. Marie area. Based on asset condition assessment, approximately 70km of the circuit's conductor from Goulais TS (str # 129) to MacKay TS is the original conductor is in poor condition as it has multiple component (sleeves) failures. The TWG recommends that the existing conductor and wood pole that are end-of-life be replaced with new 115 kV rated line and structures. This alternative will also allow Sault No.3 to return to its network configuration. The project is planned to be completed in 2024.

- **Batchawana TS and Goulais TS Refurbishment**
  Batchawana TS and Goulais Bay TS are load supply stations with single transformer to supply to the Batchawana Bay and Goulais Bay areas. Goulais Bay TS is about 30 km North of Sault Ste. Marie, while Batchawana TS is about 47 km North of Sault Ste. Marie along Hwy 17. Both are connected to 115kV No.3 Sault circuit. Based on asset condition assessment, both stations are at end-of-life with obsoleted equipment including power transformers, protections (fuse), batteries, chargers, steel structure foundations and remote terminal units. Both stations are also built with legacy design standards and do not provide adequate clearance to today's standard. Depending on the choice of distribution voltage, there are two (2) different scenarios (12.5kV vs 25kV) for each option above. Evaluation of alternatives was completed by HOSSM and API as documented in the 2021 East Lake Superior Regional Local Planning Report. As per recommendation, HOSSM is proceeding to refurbish both Goulais Bay TS and Batchawana TS using a new 115kV, 3–phase power transformer, with provision for a 115kV Mobile Unit substation (MUS) connection facility in each station. Refurbishment for both stations are expected to be completed in 2024.

- **Northern Ave TS Transformer T1 Replacement**
  Northern Ave TS is a 115kV load supply station that is connected to Third Line TS via 115kV Northern Ave circuit. Northern Ave Transformer T1 is a 115/34.5kV, 20/26.7MVA step down transformer that supplies Algoma Power Inc. via one (1) 34.5kV feeder. Transformer T1 is at end-of-life. The TWG recommends replacing T1 with a 'like for similar' unit that has a smaller MVA rating compared to existing T1 and would be adequate for Northern Ave's long-term load forecast. It is expected to be completed by 2025.

- **Anjigami/Hollingsworth TS Transformer Overload**
  Anjigami TS is a 115kV/44kV load supply station with a single transformer. Hollingsworth TS is a 115kV/12.5kV/44kV station that supplies load on 44kV and connected to Hollingsworth CGS on the 12.5kV. Anjigami's and Hollingsworth's 44kV feeders are connected to each other with a 10km long 44kV line to supply LDC load on No.4 circuit. Based on the load forecast, the load increase on the 44kV system by end of 2024 will exceed transformer capacity in both Anjigami TS and Hollingsworth TS when the companion station is out of service. The TWG recommends building a new 115/44kV station in the vicinity of Hollingsworth TS and tap off from 115kV Hollingsworth circuit to supply new loads as well as existing load that are presently supplied by Anjigami/Hollingsworth 44kV system. The project is expected to be completed by 2025.

- **Clergue TS Switchgear Replacement**
  Clergue TS is a 115kV station that connects Clergue Generating Station and LSP co-generation station to the HOSSM system via two (2) 115kV circuits emanating from Patrick St TS. Based on asset condition assessment, the existing 12 kV minimum-oil metal-clad switchgear is at end-of-life and it is recommended to replace the existing minimal oil metal clad switch gear with SF6 metal clad switch gear. The project is expected to be completed by 2026.

- **Hollingsworth TS Protection Replacement**
  Hollingsworth TS is a 115kV station that connects Hollingsworth Generating Station and is supplied by Hollingsworth 115kV circuit. Majority of protection relay equipment in Hollingsworth TS were in-serviced 2005. Based on asset condition assessment, the existing protection relay will approach end-of-life by 2025. The TWG recommends replacing the identified items as per current standards. The project is expected to be completed by 2025.

- **Watson TS Switchgear Replacement**
  DA Watson TS is a 115kV load supply station that also has connectivity with three (3) local hydro generating stations. The station has two 45/60/75 MVA transformers and nine 34.5kV feeders using metal clad switch gear. Based on an asset condition assessment, the existing minimal oil metal clad switch gear are at end of life and it is recommended to replace existing minimal oil metal clad switch gear with SF6 metal clad switchgear. The project is expected to be completed by 2026.

It is expected that the next planning cycle for this region will be initiated in 2024 or earlier, beginning with the NA phase.

4.10 GTA East

GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa, and parts of Clarington and other parts of Durham Region. The second cycle of Regional Planning was initiated by Hydro One in 2019, with the NA report published in August 2019. The second cycle NA concluded that there were no additional needs other than h asset replacement work in the region. The TWG determined that no further regional coordination was required to address the following needs. It was recommended that the implementation and execution for the replacement of the transmission assets be coordinated by Hydro One and the affected LDCs and/or customers.
The second cycle RIP report was completed in February 2020. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- Enfield TS: Installed a new 230kV/44kV Enfield TS with six (6) 44kV feeder breaker positions with provision for two (2) additional 44kV future feeder breaker positions (completed in 2019).
- Clarington TS: Built a new 500/230kV autotransformer station to increase transmission supply capacity to the GTA East Region, eliminate the overloading of Cherrywood TS autotransformers that may result after the retirement of Pickering NGS, and improve supply reliability to the region (completed in 2018).
- Thornton TS T3/T4: Replaced end-of-life transformers. Also installed LV neutral grounding reactors to reduce line-to-ground short circuit fault levels to facilitate DG connections (completed in 2016).
- Wilson TS T1/T2 DESN1: Installed LV neutral grounding reactors to reduce line-to ground short circuit fault levels to facilitate DG connections (completed in 2015).

Needs and Plans underway in GTA East Region:

- **Cherrywood TS 230kV & 500kV Breaker Replacements**
  Cherrywood TS is a major Bulk Electricity System (BES), Northeast Power Coordination Council (NPCC) station, located at east end of Greater Toronto Area (GTA). The existing 500kV and 230kV Air Blast Circuit Breaker (ABCBs), with an average age of 48 years are obsolete and at end-of-life. The age, condition, and lack of parts present significant difficulties in maintaining these breakers and the associated high-pressure air system. The project has been divided into multiple phases. Phase 1 of this project is currently underway. The whole project is expected to be completed by 2027.

- **Cherrywood TS LV Switchyard Refurbishment**
  The LV DESN switchyard, except for step-down transformers T7 and T8, at Cherrywood TS is at end-of-life due to poor condition. This project is expected to be in-service in 2025.

- **Wilson TS T1/T2 & Switchyard Refurbishment**
  Wilson TS is located in Oshawa and it contains 4 X 75/100/125 MVA, 230/44 kV, transformers that supplies city of Oshawa through Oshawa Power feeders and surrounding areas of Oshawa through Hydro One Distribution owned feeders. The T1 and T2 transformers and majority of assets within

44 kV BY switchyard have reached end-of-life. Replacement of these assets is expected to be completed by 2024.

- **Seaton MTS**
  The construction of the MTS is in progress and is expected to be in service by end of 2022.

It is expected that the next planning cycle for this region will be initiated in 2024 or earlier, beginning with the NA phase.

4.11 London Area

The London Area includes the Cities of Woodstock, London and St. Thomas as well as the Counties of Middlesex, Elgin, and Oxford. The second cycle NA was completed in May 2020. The NA determined that identified needs in the region are local in nature and can be addressed directly by Hydro One and affected LDCs, and therefore further regional coordination is not required.

The second regional planning cycle was completed with publishing of the RIP report in August 2022. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- Aylmer TS transformers and low-voltage switchyard replacement (competed in 2017).
- Strathroy TS failed transformer T1 and low-voltage switchyard replacement (completed in 2019).
- Wonderland TS failed transformer T6 was replaced (completed in 2019).
- St. Thomas TS was decommissioned and 115 kV circuit W14 re-termination work (completed in 2020).
- Sarnia Scott TS to Buchanan TS 230 kV circuits N21W/N22W tower structures refurbishment (completed in 2021).
- Tillsonburg TS new low-voltage capacitor banks (completed in 2021) and switchyard component replacement project to be completed in 2022.

Needs and Plans underway in London Area Region:

- **Nelson TS** station refurbishment project will be completed in 2022.

- **Longwood TS** protection and control replacement project to be completed in 2023.

- **Edgeware TS** protection and control replacement project to be completed in 2024.

- **Buchanan TS Transformer Replacement**
  Buchanan TS is a major 230/115 kV transformer station in the area that supplies load stations in London Area. Two of the 3 auto transformers, T2 and T3 are 48 and 54 years old respectively, are in poor condition, and approaching end-of-life. To address poor equipment performance of deteriorating equipment, Hydro One plans to replace two 230kV autotransformers, spill

containment pits, AC and DC station service equipment, as well as some obsolete protection, control, and telecom equipment. The expected completion date is 2028.

- **Clarke TS Transformer Replacement**
  Clarke TS is a DESN station located in the northern part of the London Area. The two 230/27.6 kV 50/83 MVA transformers T3 and T4 are 55 years old, in poor condition, and approaching end-of-life. Some of the protection equipment is also found to be obsolete. To address the assets in poor condition and end-of-life, the TWG recommends replacing step-down transformers like-for-like, associated disconnect switches, 27.6 kV switchyard components including breakers, station services, capacitors, and protections. The replacement plan will be closely coordinated with affected LDCs. The expected completion date is 2028.

- **Talbot TS Transformer Replacement**
  Step-down transformers T3 and T4 have been in-service from 1979 and are in poor condition and approaching end-of-life. A number of 27.6 kV breakers and protection equipment have also been identified for replacement. According to the regional non-coincident net load forecast in the study period, Talbot TS T1/T2 DESN is expected to exceed its station capacity throughout the study period and Talbot TS T3/T4 DESN will exceed its capacity in 2029. The station capacity need was primarily driven by temporary load transfer from neighboring station (Nelson TS) which was refurbished in December 2018. London Hydro confirmed load will be transferred back to Nelson TS as more 27.6 kV distribution feeders becomes available in downtown London. Therefore, additional transformation capacity is not required at this time. The TWG recommends Hydro One to proceed with like-for-like replacement of T3 and T4 at Talbot TS. The expected completion date is 2028. In addition, Hydro One will look for opportunities to coordinate this project with London Hydro for the metal clad switchgear replacement.

- **Wonderland TS EOL Replacement**
  Wonderland TS is a DESN station located in the western part of the London Area. The 50/83 MVA T6 power transformer was replaced in 2004 due to failure. The companion transformer, T5, failed in July 2019 and was subsequently replaced. The existing air insulated 27.6 kV switchgear, majority of which are original installations have reached end-of-life due to deteriorated condition and has limited availability of parts for ongoing support and maintenance. All site protection and control equipment, consisting of first generation electro-mechanical relaying are deemed end-of-life, obsolete and require replacement. To address the end-of-life need, Hydro One plans to replace the Wonderland 27.6 kV switchyard. The replacement plan will be closely coordinated with affected LDCs and the expected completion date is 2026.

- **London Area East OPGW Infrastructure**

\- **M31W/ M32W (Salford Junction x Ingersoll)**
  M31W and M32W are 230 kV network circuits that connect Buchanan TS and Middleport Port TS. To improve the reliability of power system telecom network, Hydro One plans to install 9km of OPGW fiber from Salford Junction to Ingersoll TS and remove the existing licensed microwave link connects Ingersoll TS to Buchanan TS. The project is expected to be completed in 2027.

- **W36/W37/W5 NL/W6NL/W2S/ N21W**
  To improve the reliability of power system telecom network, Hydro One plans to establish a geographically diverse and fully redundant fiber optic network for protection and SCADA applications. A combination of Hydro One's existing and new OPGW-based fiber and two leased third-party fiber links would be utilized. The existing metallic cable will be removed, and the project is expected to be completed in 2029.

It is expected that the next planning cycle for this region will be initiated in 2025 or earlier, beginning with the NA phase.

4.12 Peterborough to Kingston

The Peterborough to Kingston Region includes the area roughly bordered geographically by the municipality of Clarington on the West, North Frontenac County on the North, Frontenac County on the East, and Lake Ontario on the South. The region includes Frontenac County, Hasting County, North Humber land County, Peterborough County, and Prince Edward County and related municipalities.

The second regional planning cycle was completed with publishing of the RIP report in May 2022. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- Load transfer from Gardiner TS DESN 1 to Gardiner TS DESN 2 to provide transformation capacity relief at Gardiner TS DESN 1 (completed in 2019).
- Connect Napanee GS– A 910 MW gas turbine (Napanee GS) was connected to the 500 kV bus in the Lennox TS switchyard (completed in 2017)

Needs and Plans underway in Peterborough to Kingston Region:

- **Cataraqui TS Line Reinforcement**
  Cataraqui TS supplies the 115kV stations in the Eastern sub region of the region through two 230/115kV auto transformers. It is forecasted that in 2023 the coincidental loading of the stations in the sub region will reach the supply capacity of the Cataraqui TS auto transformers. The current limitation of the Cataraqui TS auto transformers is due to a short span of copper conductors connected the secondary side of the auto transformers within the station. Upgrading the conductors will allow the long-term emergency to increase by 35 MW and resolve this need in the near term. The work is expected to be complete by 2023.

- **Gardiner TS DESN1 Capacity**
  Gardiner TS DESN 1 is supplied by 230 kV circuits X2H and X4H. The Gardiner TS DESN1 has exceeded its Summer 10-Day LTR which is 125 MW. To address the situation Hydro One distribution has confirmed that a permanent additional 11 MW load transfer from Gardiner TS DESN1 to Gardiner TS DESN2 is possible by reconfiguring its distribution system which is much faster and will be completed by the end of 2022. Also, in Q4 2022 Hydro One Transmission will address the current capacity limit at Gardiner TS DESN1 and will provide an update to the TWG

for refurbishment with new standard 75/125 MVA transformers that will increase the LTR to about 160 MW and address the load growth at DESN up to 2033. It is planned to be in service by 2028.

- **Frontenac TS Capacity**
  Based on the submitted load forecast, the Frontenac TS will be loaded more than the station LTR by year 2028. The TWG recommended Hydro One Transmission to coordinate with Hydro One Distribution and Kingston Hydro to undertake distribution load transfer between Gardiner TS and Frontenac TS over the near term.

- **Otonabee TS Capacity**
  Based on the 2020 net load forecast, the loading on Otonabee TS 44kV is exceeding its Summer 10-Day LTR today. Hence, there is a need for additional transformation capacity at Otonabee TS 44 kV bus in the near term. To address the situation Hydro One distribution has confirmed that a total of 12MW load can be shifted to nearby station Dobbin TS which has over 50MW of remaining capacity and is not expected to reach its LTR of 160 MW in the long term. Therefore, it will provide enough capacity to address the load growth forecast at Otonabee TS 44 kV bus until 2030 and the urgent need of upgrade is eliminated.

- **Port Hope TS Transformer Replacement**
  The T3/T4 transformers were built in 1959 and have been identified as has reached the end of service life and requiring replacement. T3/T4 currently supplies about 70 MW of load and the long-term forecast is well within the current LTR. The scope of this project is to replace T3/T4 step-down transformers, associated spill containment structure and majority of assets within 44 kV BY switchyard with the equipment of similar ratings. The targeted in-service is in year 2025.

- **Belleville TS Load Connection Inquiries**
  The summer peak loading on Belleville TS is close to its 10-day summer LTR of 161 MW. In addition to normal load growth in the area, Elexicon Energy Inc. has recently received approximately 30 MW of load connection inquiries to be connected at the Belleville TS. There is insufficient existing capacity in the area to supply the potential future connections. The Belleville TS T1/T2 transformer replacement is currently underway, with an expected in-service date of 2022, but this refurbishment is not expected to result in any significant improvement to the station's capacity and does not solve the voltage limitation issue. To address the situation Hydro One (Transmission and Distribution) and Elexicon have started development of a new DESN with two 75/125 MVA transformers with two 32 MVAR Capacitor banks with an expected in-service date of 2026. This will increase the supply capacity to the region and will resolve the capacity need at Belleville TS in the near and midterm. However, the TWG will continue monitoring the load growth at Belleville TS and revisit the capacity need in the next regional planning cycle to re-assess whether/when a transmission line reinforcement to Belleville is required in the long term.

- **Picton TS Transformer Replacement**
  Picton TS is a 230/44kV transformer station serving Hydro One Distribution. The station comprises two 50/83MVA transformers, T1/T2. Transformers T1 and T2 are currently about 60

years old and are planned for similar standard units based on their asset condition assessment and taking “right sizing” into consideration. The planned in-service date is 2026.

- **Dobbin TS Transformer Replacement**
  Dobbin TS is located near the city of Peterborough, Ontario and supplies Peterborough to Quinte loads. Dobbin TS consists of three 230/115 kV auto transformers. T1 is rated at 150/250 MVA and T5 is rated at 115 MVA. T2 is rated at 36/78 MVA and currently out of service. During the previous planning cycle, T2 and T5 were planned to be replaced with one 150/250 MVA unit. However, as T1 has also reached the end of service life, it would be more efficient and cost effective to replace all three transformers with two 150/250 MVA units. The work is expected to complete in the year 2029.

It is expected that the next planning cycle for this region will be initiated in 2025 or earlier, beginning with the NA phase.

4.13 South Georgian Bay/Muskoka

The geographical area of the South Georgian Bay/Muskoka Region is the area roughly bordered by West Nippising on the North-West, the Algonquin Provincial Park on the Northeast, Scugog on the South, Erin on the South-West, and Grey Highlands on the West. The second cycle Needs Assessment of this region was completed in April 2020.

The IRRP was later completed in June 2022. The RIP report is currently underway. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- Barrie TS: Transformer supply capacity will be exceeded, and consequently result in thermal violation of the radial supply circuits (E3B/E4B) and majority of EOL equipment resulted in creation of the Barrie Area Transmission Reinforcement (BATU) project which is presently underway.
- M6E and M7E circuits (at Orillia TS): installed 230 kV motorized disconnect switches in 2021.
- Minden TS: Replaced 230/44kV 42MVA (T1/T2) transformers with new 230/44kV 83MVA units in 2021.

Needs and Plans underway in South Georgian Bay/Muskoka Region:

- **Parry Sound TS Capacity**
  Transformer supply capacity has been exceeded, and transformers have also been assessed at being end of life and in need of replacement due to asset condition. Hydro One will be installing new 230/44kV 83MVA transformers to address both end of life and supply capacity needs. The in-service is scheduled for 2024.

- **Orangeville TS EOL Replacement**
  Replace and upgrade existing 230/44kV 83MVA transformers (T3/T4) with new 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. These transformers and associated low voltage equipment have been assessed at being end of life and in need of replacement due to asset condition. This is presently underway with an In-Service scheduled for 2023.

- **Everett TS Capacity**
  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. This will provide the ability to utilize the full supply capability of the transformers at Everett TS and alleviate the need. The need is expected to be addressed before Everett TS reaches its summer 10-day LTR (2025) with an approximate cost of 0.5M.

- **Barrie TS Capacity**
  Transformer supply capacity will be exceeded and consequently result in thermal violation of the radial supply circuits (E3B/E4B). Most of the equipment at Barrie TS as well as the Essa TS 115kV yard have also been assessed at being end-of-life and in need of replacement due to asset condition. This resulted in creation of the Barrie Area Transmission Reinforcement (BATU) project to address these needs. This investment in presently underway. Barrie TS is also expected to reach its summer 10-day LTR 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 TWG recommends constructing a new 230/27.6 kV transformer substation which would connect to the upgraded circuits E28B/E29B (that will be available post BATU). The project is expected to be completed by 2025.

- **E8V/E9V EOL Replacement**
  Sections of circuits E8V/E9V will reach end-of-life by 2027. The TWG recommends like-for-like replacement of these assets. It is expected that the replacement will be completed in 2027.

- **M6E/M7E Supply Capacity**
  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. The TWG recommends monitoring demand growth in the area; consider CDM options in next cycle of regional planning as a means of deferring transmission upgrade with a schedule to be done by 2034.

- **Midhurst TS Capacity**
  Midhurst TS is expected to reach capacity by 2035. Given the timing of the need, no firm recommendation is required at this time. The TWG will continue monitoring demand growth in the area and revisit these needs in the next cycle of regional planning.

- **Alliston TS Capacity**
  Alliston TS is expected to reach summer 10-day LTR by 2037. Given the timing of the need, no firm recommendation is required at this time. The TWG recommends monitoring demand growth to ensure load supplying capability is maintained and revisit the need in the next cycle of regional planning.

- **Essa TS Thermal Capacity**
  A thermal capacity need on one of the Essa 500/230 kV autotransformers for loss of the companion autotransformer arising in 2022 is identified. This will be further studied as part of Essa Bulk Study led by IESO.

- **Minden TS Capacity**
  Minden TS is expected to have station capacity need by 2038. Given the timing of the need, no firm recommendation is required at this time. The TWG recommends monitoring the load growth in the area and providing enough lead time to capture changes into the next cycle of regional planning where these needs can be revisited.

- **Waubaushene TS Capacity**
  Waubaushene TS transformers are approaching end-of-life in 2030 and was planned for replacement at this time; however, current needs show an earlier replacement is required. Waubaushene TS will be over its 10-day summer LTR in 2027. It is recommended to consider incremental, cost-effective CDM to defer the need arising in 2027 until the EOL transformers are replaced. 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 second cycle RIP will further explore this backstop solution.

- **M6E/M7E (Minden x Copper) System Capacity**
  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. The TWG 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 TWG should continue to consider incremental, cost-effective CDM in between cycles and in the next cycle of regional planning in the region.

- **D1M/D2M & M6E/M7E (Orillia x Copper) Replacement**
  No violations were identified for the identified circuits in system studies and a like-for-like replacement with the closest available standard was recommended and can best address the end-of-life needs at sections of D1M/D2M and M6E/M7E. The replacement is expected to be completed by 2028 and 2024 respectively.

4.14 Sudbury/Algoma

The Sudbury/Algoma region includes the municipalities of Greater Sudbury and Espanola and surrounding areas. There are municipal LDCs serving each of those municipalities and Hydro One

Distribution serves the remainder of the Region. The area is supplied from transformer stations Clarabelle TS, Coniston TS, Elliot Lake TS, Larchwood TS, Manitoulin TS, and Martindale TS. The second cycle Needs Assessment was completed in June 2020.

The NA determined that identified needs in the region can be addressed directly by Hydro One along with relevant LDCs, and therefore the SA and IRRP were not required. The second regional planning cycle was completed with publishing of the RIP report in December 2020. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- Espanola TS: Replaced 115/44 kV 15MVA (T1) and 42MVA (T2) transformers with new 115/44 kV 42 MVA units (completed in 2016).
- Larchwood TS: Replaced 110/44 kV 20 MVA (T2) transformer with a new 115/44kV 42MVA unit (completed in 2015).
- Martindale TS: Replaced (T21, T22 & T23) autotransformers with 125MVA 230/115kV units, five (5) 230kV breakers and disconnect switches (completed in 2022).
- Manitoulin TS: A CT ratio setting on the low voltage bushing of the transformer breaker was modified to allow full transformer LTR capability (completed in 2021).
- Algoma TS: The EOL T5 and T6 autotransformers were replaced with standard 125 MVA units (completed in 2022).
- Due to the removal of the Coniston TS its load was planned to be transferred to a newly built Hanmer TS DESN, but due to customers' changing system needs, this plan was reviewed and it evolved into the removal of the station in concurrence with the conversion of the legacy 22kV loads to 27.6kV and their transfer onto one of the feeders originating from Martindale TS (completed in 2021).

Needs and Plans underway in Sudbury/Algoma Region:

- **Hanmer TS to Martindale TS decoupling**
  With either X25S or X26S out of service, the loss of the companion circuit may result in voltage declines at Martindale 230kV and 115kV buses below acceptable ORTAC[5]. The scope of this project aims to decouple one of the two circuits (X25S or X26S) into its own position at both Hanmer TS and Martindale TS. Hydro One initiated this project as per IESO's recommendation provided via a letter dated October 19, 2018. The expected in-service date is 2023.

- **Martindale TS EOL Replacement**
  Martindale TS is a 230/115kV BES classified station which also includes a 230kV/44kV DESN station located in Sudbury that supplies both LDCs identified in the Sudbury/Algoma region. The DESN station is comprised of two (2) – 125 MVA 230/44kV power transformers. These power transformers as well as select 44 kV equipment are approaching their EOL and the TWG recommends they are replaced with Hydro One standard equipment of similar size and capabilities. The replacement is expected by 2028.

- **Clarabelle TS EOL Replacement**
  Clarabelle TS is a 230/44kV transformer station located in the Sudbury/Algoma region. The station features two 230/44kV 125 MVA step down transformers that supply both identified LDCs in the Sudbury/Algoma region. The power transformer at Clarabelle TS as well as select station equipment are approaching their EOL and the TWG recommends they are replaced. The replacement is expected by 2027.

- **Elliot Lake TS Transformer Replacement**
  Elliot Lake TS is a Hydro One transformer station located west of Sudbury. The station consists of two (2) 115/44kV 42 MVA transformers (T1 and T3) alongside one 115kv/44kV 19 MVA transformer (T2). A station asset condition assessment has identified T1 and T2 for replacement within the mid-term horizon. Concurrently, recent supply need assessment at the station has deemed T2 no longer necessary to maintain supply reliability and adequacy at the station. The LDC supplied from Elliot Lake TS further concurred that T2 can be removed from Elliot Lake TS without impacting their supply reliability and adequacy. As such, this project will see the like-for-like replacement of T1 transformer, the removal of T2 transformer and the reconfiguration of the station to a near standard Jones DESN design. The TWG recommends proceeding with removal of T2 and replacement of the end-of-life assets as per existing station refurbishment and reconfiguration plans at Elliot Lake TS.

It is expected that the next planning cycle for this region will be initiated in 2025 or earlier, beginning with the NA phase.

4.15 Northwest Ontario

The Northwest Ontario region encompasses a large geographic area, stretching from the town of Marathon to the western and northern borders of the province, with diverse characteristics.

The second cycle Needs Assessment was completed in July 2020. The IRRP work is in progress and expected to be completed by December 2022. The second cycle RIP will follow when the IRRP is completed. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- E1C (Ear Falls TS x Crow River DS): The new 230kV Watay connection between Pickle Lake SS and Dinorwic Jct. to provide relief to the capacity constraint on E1C (completed in 2022).
- Red Lake Sub-System: New 230kV Watay connection between Pickle Lake SS and Dinorwic Jct. which provided relief to E4D &E2R (completed in 2022).
- Birch TS: HV Breaker, Disconnect Switch, and Insulator replacement (completed in 2020).
- Dryden TS: Three existing (3) non-standard 115/44kV step-down transformers were replaced by two (2) new standard 115/44kV step-down transformers (completed in 2020).
- Alexander SS: EOL HV Breakers and Line disconnect switches replaced (completed in 2022).
- Ear Falls TS: EOL HV breakers replaced (completed in 2022).

Needs and Plans underway in North-west Ontario Region:

- **Pine Portage SS:** EOL HV Breaker, Disconnect Switch and Protection & Control facilities replacement to be completed in 2024.

- **Ring of Fire Sub-System**
  The North of Dryden IRRP indicated that since the Ring of Fire area is remote from the existing transmission system, any additional capacity needs would require new facilities. It indicated that transmission system connection, either from Pickle Lake or from the Marathon area, is the most economic option when compared to diesel generation. Development in the area is still in the early stages and no firm recommendations are made at this time. To meet the forecast demand from LDCs, as reported in 2016, with the cancellation of the Energy East pipeline project and the current plans of new mine for embedded generation to meet their supply requirements, no new system enhancements were identified. Accordingly, new industrial and/or mining loads will be monitored, and investments will be initiated once formal connection requests are received from the customer(s).

- **Dryden TS Supply Capacity**
  The West of Thunder Bay IRRP from the previous planning cycle indicated that under high load growth scenario, additional capacity of 50MW will be required on the Dryden 115kV Sub-System by mid-2020s. The IRRP indicated that the Dryden 115kV Sub-System can provide up to 240MW of continuous supply to Dryden 155kV Sub-System and North of Dryden Sub-Region. As per the current load forecast, the Dryden 115kV Sub-System is forecasted to be 80MW, and the North of Dryden Sub-Region is forecasted at 97MW. The total demand from these two systems is 177MW, and this is a significant decline from the IRRP forecast of 310MW. The TWG recommends further regional coordination to study different growth scenarios for the Dryden 115kV Sub-System and the resulting impact they may present.

- **Kenora MTS Capacity**
  Kenora MTS is a 115kV load station owned by Synergy North and its forecasted load growth is anticipated to reach 23MW by year 2027, which is also the station's Winter 10-Day Limited Time Rating ("LTR"). The TWG recommends expanding/modifying Kenora MTS to accommodate load growth past 2027 by Synergy North in co-ordination with Hydro One as part of Local Planning. However, this need may be revisited later should additional findings during subsequent phases of regional planning trigger the TWG to reconsider the recommendation made in the NA phase.

- **Marathon TS Load Growth**
  With the sizable load increase in the Greenstone-Marathon Sub-Region, under loss of both autotransformers at Marathon TS contingency, Marathon Sub-Region system experiences voltage collapse. The TWG recommends further regional coordination and assessment during the next phases of regional planning to address this issue.

- **Port Arthur TS Transformation Capacity**
  The limiting low voltage equipment at Port Arthur is being replaced and upgraded with expected completion by 2025. This upgrade will bring the total station capacity up to 59 MW from the current 55MW, sufficient to meet the demand beyond 2029. Port Arthur TS load growth will be

actively monitored, and potential supply options will be re-evaluated in the next regional planning cycle. No further actions are required at this time.

- **Lakehead TS Capacity**
  With the projected sizable load growth and substantial decrease in dependable generation output assumption in the Thunder Bay Sub-Region, voltage support will be required, while at the same time mitigation is required to prevent overloading of the 115kV circuits A5A, A1B, and T1M under loss of T7 and T8 outage condition. The TWG recommends further regional coordination and assessment during the next phases of regional planning to address this issue.

- **Sapawe DS Capacity**
  This station is a 115/12.5kV distribution station owned by Hydro One Distribution. The station is anticipated to reach its winter and summer Planned Loading Limit (PLL) levels by year 2028 and 2026 respectively. The TWG recommends that the Sapawe DS capacity need be addressed as part of Local Planning.

- **Sam Lake DS Capacity**
  The station is the sole supply for Sioux Lookout Hydro and this embedded LDC is anticipating having a significant load increase up to 35MW throughout the next 10-year period. The existing transformation facility at Sam Lake DS has already reached its Winter 10-Day LTR and various options including adding an additional step-down transformer or having a brand-new station built in the vicinity are being considered. Due to the significant load increase, additional voltage support will also be needed at this station. The TWG recommends that the Sam Lake DS capacity need be addressed as part of Local Planning.

- **Asset Replacement for Major HV Transmission Equipment**
  Hydro One has identified the need for replacement of major HV transmission assets over the next ten years at a number of stations in this region as shown below. The TWG recommendations for asset replacement plans have taken "right sizing" into consideration.
  - **A4L:** Refurbishment of Beardmore Jct x Longlac TS section (planned in-service date is 2025)
  - **E1C:** Ear Falls TS x Slate Falls DS section and Etruscan Jct x Crow River DS section have been prescribed for line refurbishment (planned in-service date is 2025)
  - **Fort Frances TS:** The two (2) 230/115 kV step-down autotransformer and 115 kV breakers at the station are reaching EOL (planned in-service date is 2027)
  - **Kenora TS:** The existing step-down autotransformer, as well as HV breakers and switches are reaching EOL (planned in-service date is 2025)
  - **Lakehead TS:** The existing HV breakers, switches, and Protection & control facilities at the station are approaching EOL (planned in-service date is 2025)
  - **Mackenxie TS:** The existing 230/115 kV autotransformer as well as HV breakers and line disconnect switches are near EOL (planned in-service date is 2024)
  - **Marathon TS:** The existing HV breakers at this station is approaching EOL (planned in-service date is 2024)
  - **Moose Lake TS:** The existing two (2) 115/44kV step-down transformer and LV breakers are near EOL (planned in-service date is 2024)

4.16 Chatham/Lambton/Sarnia

The Chatham-Lambton-Sarnia region is located to the west of the Greater Toronto Area in southwestern Ontario. The region includes the municipalities of Lambton Shores and Chatham-Kent. It also includes the Townships of Petrolia, Plympton-Wyoming, Brooke-Alvinston, Dawn-Euphemia, Enniskillen, St. Clair, Warwick and the Villages of Oil Springs and Point Edward. The second cycle NA was completed in September 2021. The NA determined that the identified needs in the region are local in nature and can be addressed directly by Hydro One and affected LDCs, and therefore no further regional coordination is required.
The second regional planning cycle was completed with publishing of the RIP report in August 2022. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- Chatham SS: 230 kV capacitor bank replaced (completed in 2020).
- Wanstead TS: Refurbished with 50/66/83MVA transformers and its supply was upgraded from a single 115kV connection to a double 230kV connection (completed in 2018).

Needs and Plans underway in Chatham/Lambton/Sarnia Region:

- Chatham SS Component Replacement, mainly to replace capacitor SC21 and the associated breaker and is planned to be completed by 2023.
- St. Andrews TS T3, T4 & Switchyard Refurbishment is planned to be completed by 2025. The current scope includes both transformers and breaker replacement.
- Sarnia Scott TS T5 & Component Replacement, which includes autotransformer T5, breaker, and other components is planned to be completed by 2024.
- New Lambton by Chatham transmission line is currently under development with a projected in-service date in 2028.
- Lambton TS switchyard is currently undergoing major station refurbishment work with a projected in-service date in 2023.

- **Circuits L28C/L29C Transmission Circuit Capacity**
  The L28C/L29C double-circuit transmission line will start to experience capacity issues and voltage violations in the medium term due to significant capacity needs in the neighboring Windsor-Essex region and new connections in Dresden Area. To address the potential need for additional capacity and improved voltage performance along this corridor, Hydro One has agreed with IESO's recommendation to construct the new 230kV double-circuit transmission line which is expected to be in-serviced in 2028. The selection of the preferred route for the new double-circuit line is anticipated in Q2 2023.

- **Wallaceburg TS and Kent TS Area (Dresden Area) Transformation Capacity**
  There is potentially a strong need for capacity in the Dresden Area which is currently supplied by Wallaceburg TS and Kent TS. Hydro One to move forward with IESO's recommendation of constructing a new station (proposed to be named Dresden TS) on the Lambton by Chatham corridor. Due to the existing limitations on the L28C/L29C circuits the construction of the new

Dresden TS would be aligned with the construction of the new Lambton by Chatham transmission line with the intention of being ready to connect new customers when the new double-circuit line is completed in 2028. The immediate capacity needs of new customers can be supplied by the limited capacities available at Kent TS (T1/T2 DESN) and Wallaceburg TS until the proposed Dresden TS is placed in-service. The need for Dresden TS may possibly be delayed if the Lambton by Chatham routing results in additional capacity becoming available at Wallaceburg TS.

- **St. Andrews TS Capacity**
  St. Andrews TS will reach its LTR in 2024 from which point it will continue to grow at an average rate of less than 0.5% towards the end of the study period. As the station is expected to slowly start exceeding its LTR, additional capacity is required. Hydro One is planning to replace the older transformer unit with a new one with higher LTR, adding 20 MVA to provide sufficient capacity for the long-term. The replacement of the transformer is expected to be completed in 2025.

- **Forest Jura HVDS**
  Forest Jura HVDS is expected to reach its LTR in 2030. If the forecast materializes as expected, additional capacity will be required in the long-term. To address the potential capacity need at Forest Jura HVDS, the TWG recommends that Hydro One Distribution monitor the loading and determine a plan to ensure the station can meet the capacity demand.

- **Circuit N5K Voltage Performance**
  Assuming large load growth at Wallaceburg TS in the absence of the proposed Dresden TS, there would be voltage violations on the 115kV N5K circuit. This violation is mitigated with the new Dresden TS in place and Wallaceburg loaded within its LTR. It is recommended to maintain loading at Wallaceburg within its capacity limit and wait for the completion of Lambton by Chatham line anticipated in Q2 2023, which will determine if the supply voltage to Wallaceburg TS is increased to 230kV.

- **Circuits L28C/L29C Bulk System Performance**
  Accounting for needs in neighboring Windsor-Essex Region, there is a bulk system need to reinforce the 230kV corridor between Lambton and Chatham. There are several large-scale combined-cycle gas plants in this area whose output could vary depending on broader system conditions such as expected load growth and availability of other generation resources. The IESO undertook a study to assess the bulk system adequacy for the West of London area, under different system conditions. As a result, the need to reinforce the Lambton-by-Chatham corridor was identified. Hydro One will proceed with the recommendation of IESO to construct a new double-circuit transmission line between Lambton and Chatham to address bulk system reinforcement needs. The project is expected to be completed in 2028.

- **Asset Replacement for Major HV Transmission Equipment**
  Hydro One has identified the need for replacement of major HV transmission assets over the next ten years at a number of stations in this region as shown below. The TWG recommendations for asset replacement plans have taken “right sizing” into consideration.

- **Lambton TS:** Replacement of T7/T8 auto-transformers and associated switches, replacement of T5/T6 DESN transformers and associated switches & replacement 27.6kV switchyard and associated equipment (planned in-service date is 2023)
- **Scott TS:** Replacement of T5 auto-transformer, replacement of 115kV switchyard and associated equipment (planned in-service date is 2024)
- **St. Andrews TS:** Replacement of T3/T4 DESN transformers and associated switches & replacement of 27.6kV switchyard and associated equipment (planned in-service date is 2025)
- **Kent TS**: Replacement of T2 DESN transformers and associated switch, complete 27.6kV switchyard and associated equipment (planned in-service date is 2027)
- **N1S/N4S:** Refurbishment of circuit section between Scott TS and Vidal JCT (planned in-service date is 2027)
- **N6C/N7C:** Refurbishment of circuit section between Scott TS and St. Andrews TS (planned in-service date is 2027)
- **S2N:** Refurbishment of circuit section between Scott TS and Adelaide JCT (planned in-service date is 2025)
- **N5K:** Refurbishment of circuit section between Scott TS and Kent TS* (planned in-service date is 2027)

It is expected that the next planning cycle for this region will be initiated in 2026 or earlier, beginning with the NA phase.

4.17 Niagara

The Niagara Region comprises the municipalities of City of Port Colborne, City of Welland, City of Thorold, City of Niagara Falls, Town of Niagara-On-The-Lake, City of St. Catharines, Town of Fort Erie, Town of Lincoln, Township of West Lincoln, Town of Grimsby, Township of Wainfleet, and Town of Pelham. Haldimand County was also included in the Niagara Region.

The second cycle NA was completed in May 2021. The IRRP is currently underway with tentative completion in November 2022. The RIP will follow once the IRRP is completed. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- Upgrade Sir Adam Beck SS #1 x Portal Junction section of 115kV circuit Q4N (completed in 2019).

Needs and Plans underway in Niagara Region:

- **Beamsville TS Capacity**
  Beamsville TS has a summer 10-day LTR of 60.3MW and will exceed its normal supply capacity by 2027 based on the summer demand forecast. Between 2019 and 2020, there has been a 12% surge (6.6MW) in load between the historical peak demand. It is uncertain if this temporary increase is a result of the pandemic with more residents working from home, as the 10-year load forecast is only expecting a modest 5% growth (3.1MW). The TWG recommends that Hydro One coordinate with the connected LDCs and their embedded customers (as needed) to address

the immediate supply capacity constraints that may appear within 2027. Hydro One will further monitor the load growth and see if any load transfers to nearby stations are required. Solution(s) will require further regional coordination to verify if non-wires options would be beneficial. All identified wire options will be best addressed through local planning led by Hydro One.

- **Crowland TS Capacity**
  Crowland TS presently has a 10-Day LTR of 102MW which will exceed its normal supply capacity in the year 2026 based on the summer demand forecast. The Crowland TS project to replace the two EOL transformers T5 and T6 is currently underway. The two new 115/27.6kV 83MVA transformers are expected to increase the station supply capacity to at least 107 MW based on minimum 10-day LTR capability of new transformers. With the new units installed, station LTR will be exceeded in the summer 2028 and additional supply capacity will be required. Although capacity does appear to be available for the near and mid-term, Welland Hydro and Hydro One distribution also see a supply capacity constraint at the 27.6kV feeder level by 2028. The TWG will further evaluate a new station east of the Welland Canal if nearby transformer stations cannot alleviate the demand of the new area load.

- **Power Factor Correction at Thorold TS**
  On HV side of Thorold TS, only a few instances (<54 hours/year) of power factor below 0.9 (between 0.89 - 0.9) were observed, so the TWG recommended Hydro One to continue monitoring the power factor with LDC decided.

- **Asset Replacement for Major HV Transmission Equipment**
  Hydro One has identified the need for replacement of major HV transmission assets over the next ten years at a number of stations in this region as shown below. The TWG recommendations for asset replacement plans have taken "right sizing" into consideration.
  - **Port Colborne TS:** Complete station refurbishment that will replace all assets including transformers T61, T62, medium voltage switching facilities and station protection and control equipment (planned in-service date is 2022)
  - **Thorold TS:** Replace T1 transformer with a new 45/60/75 MVA unit and the existing low voltage (LV) E/Q and B/Y metalclad switchgear (planned in-service date is 2024)
  - **Crowland TS:** Replace transformers T5 and T6 with 50/66.7/83.3 MVA units (planned in-service date is 2024)
  - **D1A/D3A:** Line refurbishment of 2.6km route length between Gibson JCT x Thorold TS (planned in-service date is 2024)
  - **Q2AH:** Line refurbishment of 11.2km between Rosedene JCT X St. Anns JCT (planned in-service date is 2025)
  - **Murray TS:** Replacement of T13 and T14 power transformers and metalclad at Murray TS (planned in-service date is 2025)
  - **Bunting TS:** Replacement of transformer T3, all station medium voltage switching facilities considered legacy and non-standard along with deploying a new protection and control protocol for all station protection and control equipment (planned in-service date is 2026)

- **Carlton TS:** Replace existing H/K metalclad switchgear & B/Y switchyard with current Hydro One standard indoor air insulated (AIS) metalclad switchgear (planned in-service date is 2026)
- **Glendale TS:** Replace the existing 45/60/75 MVA T1 & T2 transformer with new 45/60/75 MVA units and Replace and reconfigure the LV switching facilities with current Hydro One standard air insulated (AIS) metalclad switchgear (planned in-service date is 2027)
- **Vansickle TS:** Replacement of the 14.2kV BY metalclad (planned in-service date is 2027)
- **Murray TS:** Replacement of T11 and T12 power transformers at Murray TS (planned in-service date is 2029)

4.18 North/East of Sudbury

The geographical area of the North/East of Sudbury Region is the area roughly bordered by Moosonee on the North, Hearst on the North-West, Ferris South and Kirkland Lake on the East.
In the first regional planning cycle, Hydro One completed the RIP report in April 2017. The TWG at the time determined that no further regional coordination was required. The second cycle NA and SA reports were completed in May 2021 and August 2021 respectively. The IRRP is currently underway with a tentative completion in February 2023. The second cycle RIP will follow once IRRP is completed. Updates to the needs and plans recommended in this region are provided below:

Needs identified from the previous cycle were addressed as part of a local plan with area LDCs. The TWG did not recommended any additional system investments as an outcome of the LP and agreed to continue monitoring the identified performance issues and take corrective action as required.

Needs and Plans underway in North/East of Sudbury Region:

- **Area Voltage Control**
  Both Hydro One and IESO continue to experience operating challenges in maintaining acceptable voltages at high voltage station buses in the region. A specific concern is the management of high voltages for buses at Hunta, Porcupine, Pinard and Kapuskasing during planned maintenance and outage conditions. Existing operating procedures employ the use of various shunt voltage controlling devices in the system and will be reviewed to ensure continued effectiveness. The TWG recommended further regional coordination and assessment during the next phases of regional planning.

- **Thermal Limits**
  This region has received significant interest in customer connections in the Kirkland Lake/Dymond and Timmins/Porcupine area. Post contingency load rejection will allow customers to connect in this region; however, increasing loads beyond the applications that presently exist will further stress system capability and thermal limits in the region. System operations also experience increasing challenges in maintaining area circuits within thermal limits during planned outages to the 500kV circuits P502X and D501P. These outages require daily switching of the 500kV circuits affecting customers, and exposes transmission equipment to stresses, which can cause premature failure. Existing operating procedures should be reviewed in conjunction with the available equipment to ensure system operations can continue

to maintain thermal limits during outage conditions. The TWG recommended further regional coordination and assessment during the next phases of regional planning.

- **Asset Replacement for Major HV Transmission Equipment**
  Hydro One has identified the need for replacement of major HV transmission assets over the next ten years at a number of stations in this region shown below. The TWG recommendations for asset replacement plans have taken “right sizing” into consideration.
  - **Porcupine TS**: Replace 1-360MVA 500kV/230kV autotransformer (T8), and 2-225MVA 500kV/115kV autotransformers (T3/T4) with units of similar size and voltage ratings (planned in-service date is 2025)
  - **Kapuskasing TS:** Replace high and low voltage circuit breakers (planned in-service date is 2026)
  - **Otto Holden TS**: Replace 2 – 60MVA 230 kV/115 kV autotransformers (T3/T4) with a new 125MVA 230kV/115kV unit, high voltage breakers (planned in-service date is 2026)
  - **Timmins TS:** Replace 1-83MVA 115/27.6kV transformer (T2) with a unit of similar size and voltage rating (planned in-service date is 2027)
  - **Crystal Falls TS:** Replace 2-42MVA 230/44kV transformers (T5/T6) with units of similar size and voltage ratings (planned in-service date is 2028)
  - Trout Lake TS: Replace 2 – 125MVA 230/44 kV transformers (T3/T4) with units of similar size and voltage ratings (planned in-service date is 2028)
  - K4: Kirkland Lake TS X Matachewan JCT (planned in-service date is 2023)
  - A8K/A9K: Ansonville TS x Kirkland Lake TS (planned in-service date is 2023)
  - T61S: Timmins TS x Shiningtree JCT (planned in-service date is 2023)
  - K2: Kirkland Lake TS x American Barrick JCT (planned in-service date is 2024)
  - D2H/D3H*: Pinard TS x Hunta SS (planned in-service date is 2025)
  - A4H/A5H*: Tunis JCT x Fournier JCT (planned in-service date is 2027)
    *Replacement of the assets for D2H/D3H and A4H/A5H identified above, will require further regional coordination.

4.19 Renfrew

The Renfrew Region includes all of Renfrew County that is made up of 17 municipalities and City of Pembroke. The rough boundaries of this Region are Ottawa River on the North-East, Algonquin Provincial Park on the West, and Route 508 on the South.

The second cycle of Needs Assessment and Scoping Assessments for this region were done in May 2021 and August 2021 respectively. The second cycle IRRP is currently underway and tentative completion is December 2022. The RIP will follow once the IRRP is completed. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- Chenaux TS: T3 & T4 transformers along with regulators TR3 and TR4, 115 kV oil circuit breakers 4X6 and 4X2Y, and protection and control equipment were replaced (completed in 2021).

Needs and Plans underway in Renfrew Region:

- **Pembroke TS Line/Station Capacity**
  The 2019 summer peak loading on Pembroke TS was 48 MW, which is above its 10-day summer LTR of 47 MW. Based on the load forecast, Pembroke TS will be loaded to 52 MW by 2029. Load relief is required at Pembroke TS in the near term. The TWG recommends that Hydro One Distribution undertake load transfer studies to alleviate Pembroke TS overloading concerns in the near term. Alternatively, Hydro One Distribution may also assess the option of building a new distribution transformer station to manage Pembroke TS overloading and to serve future load growth in the area.

- **Asset Replacement for Major HV Transmission Equipment**
  Hydro One has identified the need for replacement of major HV transmission assets over the next ten years in this region as shown below. The TWG recommendations for asset replacement plans have taken “right sizing” into consideration.
  - D6 Circuit: Circuit D6 is a 98.2 km, 115 kV, single circuit, wood pole transmission line that provides connection between Des Joachims TS and Pembroke TS. Between Des Joachims TS and Pembroke TS, this circuit also provides connecting taps to distribution stations Craig DS, Deep River DS and Petawawa DS. The 76.8 km line sections between Des Joachims TS and Petawawa/Craig DS contain multiple ACSR conductor segments that have been verified through testing to have reached end-of-life. As the other assets along this line are of original vintage and therefore beyond expected service life, this confirmed sustainment need has triggered the complete line refurbishment of transmission circuit D6 between Des Joachims TS and Petawawa/Craig DS. The goal of this refurbishment project is to completely renew all end-of-life assets along circuit D6. Currently, the work is in progress and the expected in-service for this project is end of 2022.

4.20 St. Lawrence

The St Lawrence Region covers the southeastern part of Ontario bordering the St Lawrence River. The region starts at Gananoque on the eastern end of Lake Ontario and extends to the inter-provincial boundary with Quebec. The City of Cornwall is supplied by Fortis Ontario with transmission lines from Quebec and is not included in this Region.

The second cycle Needs Assessment for this region was completed in September 2021. The NA determined that the identified needs in the region are local in nature and can be addressed directly by Hydro One and affected LDCs, and therefore further regional coordination is not required. The second cycle RIP was completed in March 2022. Updates to the needs and plans recommended in this region are provided below.

Projects completed include:

- Chesterville TS: Replaced 25/33/42 MVA, 115/44 kV step down transformers with new 25/33/42 MVA, 115/44 kV (completed in 2014).
- St. Lawrence phase shifting transformer PS33 replaced (completed in July 2022).

Needs and Plans underway in St. Lawrence Region:

- **L22H: Replacement of Conductor, Shield wire, Insulator and Tower Work**
  A total of 65 km of 230 kV circuit L22H between Easton JCT X Hinchinbrook North JCT requires refurbishment. The work includes the replacement of conductors, shield wire, insulators, and refurbishment of lattice steel structures. The TWG recommends that refurbishment of L22H between Easton JCT X Hinchinbrook North JCT does not require further regional coordination. The implementation and execution plan for this need will be coordinated by Hydro One and affected LDCs. The work is expected to be completed in 2026. No other needs have been identified and further assessment of the St. Lawrence region will be undertaken by the TWG in the next regional planning cycle.
- **St Lawrence Phase Shifting Transformers**
  Replace failed phase shifting transformer PS33 and its companion PSR34. These transformers are used to regulate the power exchanged over the Ontario-New York interconnection at St Lawrence TS. The phase shifting transformer PS33 was replaced in 2022 and PSR34 is planned for replacement in 2023.

It is expected that the next planning cycle for this region will be initiated in 2026 or earlier, beginning with the NA phase.

4.21 North of Moosonee

The lead transmitter for the region is Five Nations Energy Inc. The regional planning status will be provided by the lead transmitter.

5. CONCLUSION

The first regional planning cycle was successfully completed in August 2017 and the second regional planning cycle is currently underway. In the second cycle, regional planning for some regions had to be advanced due to emerging needs. The third cycle of regional planning was initiated in 2022 with completion of one (1) Needs Assessment (NA) and three (3) NA's underway.

Representatives from Hydro One transmission, the IESO, and LDCs actively participated on regional Technical Working Groups (TWG) during the various phases of the regional planning process. The TWGs were able to undertake the appropriate level of planning based on the needs and make efficient and effective decisions. For example, during the NA phase the TWG identifies needs, assesses options to address them, and finally recommends a preferred plan and/or further assessments as part of the next phases of the regional planning process, namely, SA, IRRP, and/or RIP. In addition, the concept of Local Planning is utilized for further assessment by a smaller TWG in cases where needs are local in nature and straightforward wires-only options are the appropriate solution. Accordingly, assessments for these needs do not require further regional coordination and are directly planned and coordinated for implementation by Hydro One Transmission and affected LDC(s) (or customers). Frequently, wires planning is also initiated in parallel with the IRRP phase when the TWG determines that a wires approach is the best alternative to address a need and allows for efficiencies in the process by starting the planning prior to triggering the RIP phase.

The sharing of information by TWG members and publishing of reports and other relevant information on Hydro One and IESO websites allows stakeholders to be aware of current and future plans that may influence their planning strategies. This transparency and stakeholder engagement were intended as one of the hallmarks of the regional planning process as envisioned by the Board.

Since the beginning of the second cycle of the regional planning process, Hydro One, LDCs, and the IESO have been able meet mandatory timelines to complete each of the regional planning phases. To summarize, below are significant milestones that have been accomplished in the second cycle and third cycle to date:

- Regional Infrastructure Planning (RIP) reports completed for fifteen (15) regions (Burlington to Nanticoke, Toronto, Windsor-Essex, GTA North, Greater Ottawa, East Lake Superior, GTA East, Sudbury/Algoma, Kitchener-Waterloo-Cambridge-Guelph, GTA West, Greater Bruce/Huron, London Area, Peterborough to Kingston, Chatham/Lambton/Sarnia and St. Lawrence), one (1) RIP is underway (Southern Georgian Bay/Muskoka) and RIP reports for the remaining four (4) regions (Northwest Ontario, Niagara, North/East of Sudbury and Renfrew) will be completed following the completion of their respective IRRPs.
- Needs Assessment (NA) reports completed for twenty (20) regions. (Refer to Table 1). Note that St. Lawrence NA was initiated two (2) month over the five (5) year period because of an error in oversight. The third cycle of regional planning was also initiated in 2022 with completion of one (1) NA (Burlington to Nanticoke) and three (3) NAs are underway (Greater Ottawa, Toronto, and Windsor-Essex).
- Integrated Regional Resource Planning (IRRP) reports for eleven (11) regions (Burlington to Nanticoke, Toronto Area, Windsor-Essex, GTA North, Greater Ottawa, Kitchener-Waterloo-Cambridge-Guelph, GTA West, Greater Bruce/Huron, East Lake Superior, Peterborough to

Kingston, South Georgian Bay/Muskoka, Chatham/Lambton/Sarnia,), with four (4) currently underway (Northwest Ontario, Niagara, North/East of Sudbury and Renfrew).

From a wires infrastructure perspective, the RIP report for a region is the most important document as it provides a complete picture of the regional wires infrastructure plan. Specifically, the RIP report documents all the identified needs and wires infrastructure plans in the region including a consolidated account of needs and wires plans developed during earlier phases, i.e. NA, LP and IRRP for the region.

6. References

[1] Ontario Energy Board. "Transmission System Code". Last Revised December 18, 2018 (Originally Issued on July 14, 2000).

[2] "Planning Process Working Group Report to the Board – The Process for Regional Infrastructure Planning in Ontario". March 13, 2013. Last Revised May 17, 2013.

[3] Ontario Energy Board. "Distribution System Code". Last Revised October 1, 2022 (Originally Issued on July 14, 2000).

[4] Ontario Energy Board. "Conservation and Demand Management Guidelines For Electricity Distributors". Last Revised December 20, 2021.

[5] Independent Electricity System Operator. "Ontario Resource and Transmission Assessment Criteria (ORTAC)". Issue 5.0. August 22, 2007.

APPENDIX A. CONSERVATION, DISTRIBUTED GENERATION, AND OTHER INITIATIVES

A.1 Conservation Achievement

In March 2019, IESO received the following two Ministerial directives that include changes to reduce the cost of energy-efficiency program delivery in Ontario. The first directive of March 21, 2019 directed the IESO to centrally deliver energy-efficiency programs in the province by implementing a new Interim Framework to take effect from April 1, 2019 to December 31, 2020. The second, also received March 21, 2019 directed the IESO to discontinue and wind-down the 2015-2020 Conservation First Framework (CFF) and the Industrial Accelerator Programs.

By Ministerial Directives dated June 22, 2020 and June 10, 2021, the 2015-2020 CFF wind-down period was extended until June 30, 2021 and December 31, 2021 respectively to provide IESO the ability to assist entities delivering CDM programs impacted by COVID-19.

On September 30, 2020 the IESO received a Ministerial directive to implement a new 2021-2024 CDM Framework, which follows the conclusion of the 2019-2020 Interim Framework. The new 2021-2024 CDM Framework focuses on cost-effectively meeting the needs of Ontario's electricity system, including by focusing on the achievement of provincial peak demand reductions, as well as targeted approaches to address regional and/or local electricity system needs.

The table below shows the estimated 2021 peak demand offsets resulting from energy efficiency projects reported to occur within the respective regions.

Table 3. Conservation Status Update

Region	Verified 2021 Peak Demand Savings (MW)
South Georgian Bay/Muskoka	**2.43**
Burlington to Nanticoke	**3.39**
Northwest Ontario	**0.718**
London Area	**5.40**
KWCG	**3.88**
GTA West	**8.48**
Greater Ottawa	**2.75**
GTA East	**1.806**
Toronto	**18.09**
Windsor-Essex	**7.21**
GTA North	**8.47**
East Lake Superior	**0.325**
Greater Bruce Huron	**0.999**
Peterborough to Kingston	**2.26**

Note: Results have been mapped to planning region, and more granular results by sub-region and/or TS are not available.

A.2 Distribution Energy Resources

The table below shows the total installed and effective capacity of IESO Distributed Energy Resources ("DER") projects which have come into service or under development since the base year of the region/sub region load forecast. This does not include net or behind the meter generation. This table does not include projects which had already been in service prior to this date, except in cases where a new contract was formed to account for incremental capacity of a facility.

The equivalent effective capacity for these new generation sources is based on capacity factors consistent with the zonal assumptions applied in the region/sub region load forecast. Data is based on the IESO contract list as of August 31, 2021.

Table 4. DER Status Update

Sub region	Station	Installed Capacity (MW)	Effective Capacity (MW)	Base Year
Barrie/Innisfil	No new contracted Distributed Generation			2020 Peak
Brant	BRANT TS	9.80	2.20	2015 Peak
	BRANTFORD TS	3.80	0.80	
	POWERLINE MTS	1.80	0.40	
	TOTAL	**15.40**	**3.4**	
Bronte	BRONTE TS	2.07	0.45	2014 Peak
	CUMBERLAND TS	2.39	0.52	
	BURLINGTON DESN	1.62	0.36	
	PALERMO TS	0.00	0.00	
	TRAFALGAR DESN	0.00	0.00	
	TREMAINE TS	1.67	0.37	
	GLENORCHY MTS	1.32	0.29	
	OAKVILLE #2 TS	1.04	0.23	
	TOTAL	**10.11**	**2.21**	
Toronto	AGINCOURT TS	0.00	0.00	2019 Peak
	BASIN TS	0.00	0.00	
	BATHURST TS	0.00	0.00	
	BERMONDSEY TS	0.00	0.00	
	BRIDGMAN TS	0.00	0.00	
	CARLAW TS	0.00	0.00	
	CAVANAGH MTS	0.00	0.00	
	CECIL TS	0.00	0.00	
	CHARLES TS	0.00	0.00	
	COPELAND TS	0.00	0.00	
	DUFFERIN TS	0.00	0.00	
	DUPLEX TS	0.00	0.00	
	ELLESMERE TS	0.00	0.00	
	ESPLANADE TS	0.00	0.00	
	FAIRBANK TS	0.00	0.00	

	FAIRCHILD TS	0.00	0.00	
	FINCH TS	0.00	0.00	
	GERRARD TS	2.73	2.73	
	GLENGROVE TS	0.00	0.00	
	HORNER TS	0.00	0.00	
	JOHN TS	0.00	0.00	
	LEASIDE TS	0.00	0.00	
	LESLIE TS	0.00	0.00	
	MAIN TS	0.00	0.00	
	MALVERN TS	0.00	0.00	
	MANBY TS	0.00	0.00	
	REXDALE TS	0.00	0.00	
	RICHVIEW TS	0.00	0.00	
	RUNNYMEDE TS	0.00	0.00	
	SCARBORO TS	0.00	0.00	
	SHEPPARD TS	0.00	0.00	
	STRACHAN TS	0.00	0.00	
	TERAULY TS	0.00	0.00	
	WARDEN TS	0.00	0.00	
	WILTSHIRE TS	0.00	0.00	
	WOODBRIDGE TS	0.00	0.00	
	TOTAL	**2.73**	**2.73**	
Greenstone-Marathon	BEARDMORE DS # 2	0.000	0.000	2014 Peak
	JELLICO DS # 3	0.000	0.000	
	LONGLAC TS	0.010	0.000	
	MANITOUWADGE DS	0.000	0.000	
	MANITOUWADGE TS	8.010	8.000	
	MARATHON DS	0.000	0.000	
	PIC DS	0.000	0.000	
	SCHREIBER WINNIPEG DS	0.000	0.000	
	WHITE DOG DS	0.000	0.000	
	TOTAL	**8.02**	**8.00**	
Greater London	Buchanan TS	0.77	0.28	2015 Peak
	Clarke TS	2.77	1.48	
	Commerce Way	0.35	0.13	
	Edgeware TS	3.38	1.25	
	Highbury TS	1.26	0.47	
	Ingersoll TS	2.29	1.15	
	Nelson TS	17.96	14.86	
	Strathroy TS	1.01	0.37	
	Talbot TS	0.53	0.19	
	Tillsonburg TS	1.59	0.59	
	Wonderland TS	1.29	0.48	
	Woodstock TS	0.18	0.07	

	TOTAL	**33.37**	**21.33**	
Hamilton Burlington to Nanticoke	Dundas TS #2 (T5/T6)	0.10	0.04	2016 Peak
	Dundas TS (T1/T2)	9.59	8.68	
	Newton TS	0.02	0.01	
	Elgin TS	1.98	1.94	
	Stirton TS	0.34	0.13	
	Gage TS (T3/T4)	0.00	0.00	
	Gage TS (T5/T6)	0.00	0.00	
	Gage TS (T8/T9)	0.00	0.00	
	Birmingham TS (T1/T2)	0.00	0.00	
	Birmingham TS (T3/T4)	0.00	0.00	
	Kenilworth TS (T1/T4)	0.00	0.00	
	Kenilworth TS (T2/T3)	0.00	0.00	
	Beach TS (T3/T4)	0.02	0.01	
	Beach TS (T5/T6)	0.54	0.21	
	Lake TS (T1/T2)	0.00	0.00	
	Lake TS (T3/T4)	0.37	0.14	
	Winona TS	0.64	0.24	
	Horning TS (T1/T2)	0.53	0.20	
	Horning TS (T3/T4)	0.00	0.00	
	Mohawk TS	0.56	0.21	
	Nebo TS (T1/T2)	1.21	0.46	
	Nebo TS (T3/T4)	0.79	0.30	
	TOTAL	**16.70**	**12.57**	
KWCG	ARLEN MTS	0.00	0.00	2018 Peak
	CAMBRIDGE #1	0.00	0.00	
	CAMPBELL TS	0.00	0.00	
	CEDAR TS	0.00	0.00	
	DETWEILER TS	0.00	0.00	
	ELMIRA TS	0.00	0.00	
	FERGUS TS	0.00	0.00	
	GALT TS	0.00	0.00	
	HANLON TS	0.00	0.00	
	KITCHENER #1	0.00	0.00	
	KITCHENER #3	0.00	0.00	
	KITCHENER #4	0.00	0.00	
	KITCHENER #5	0.00	0.00	
	KITCHENER #6	0.00	0.00	
	KITCHENER #7	0.00	0.00	
	KITCHENER #8	0.00	0.00	
	KITCHENER #9	0.23	0.09	
	PRESTON TS	0.00	0.00	
	PUSLINCH DS	0.00	0.00	
	RUSH MTS	0.00	0.00	

	SCHEIFELE TS	0.01	0.00	
	WATERLOO #3	0.22	0.08	
	WOLVERTON DS	0.50	0.19	
	TOTAL	0.96	0.36	
North of Dryden	No new contracted Distributed Generation			2014 Peak
West GTA	No new contracted Distributed Generation			2019 Peak
Ottawa	ALBION TS	0.4	0.1	2018 Peak
	BILBERRY CREEK TS	0.1	0.0	
	BRIDLEWOOD MTS	0.0	0.0	
	CARLING TS	0.0	0.0	
	CENTRE POINT MTS	0.0	0.0	
	CUMBERLAND DS	0.0	0.0	
	CYRVILLE MTS	0.0	0.0	
	ELLWOOD MTS	0.0	0.0	
	FALLOWFIELD DS	0.1	0.0	
	GREELY DS	0.5	0.1	
	HAWTHORNE TS	0.1	0.0	
	HINCHEY TS	27.0	18.9	
	KANATA MTS #1	0.0	0.0	
	KING EDWARD TS	0.0	0.0	
	LIMEBANK MTS	0.1	0.0	
	LINCOLN HEIGHTS TS	0.2	0.0	
	LISGAR TS	12.0	8.4	
	MANORDALE MTS	0.3	0.1	
	MANOTICK DS	0.0	0.0	
	MARCHWOOD MTS	0.0	0.0	
	MARIONVILLE DS	0.3	0.3	
	MERIVALE MTS	0.0	0.0	
	MOULTON MTS	0.0	0.0	
	NAVAN DS	0.0	0.0	
	NEPEAN TS	0.2	0.0	
	NEPEAN EPWORTH MTS	0.0	0.0	
	OVERBROOK TS	0.0	0.0	
	RICHMOND MTS	0.0	0.0	
	RIVERDALE TS	0.0	0.0	
	RUSSELL DS	0.0	0.0	
	RUSSELL TS	0.0	0.0	
	Slater TS	0.0	0.0	
	SOUTH GLOUCESTER DS	0.0	0.0	
	SOUTH MARCH TS	0.5	0.1	
	TERRY FOX MTS	0.1	0.0	
	UPLANDS MTS #2	0.0	0.0	
	WILHAVEN DS	0.0	0.0	
	WOODROFFE TS	0.3	0.1	

	TOTAL	**42.3**	**28.2**	
GTA East Pickering-Ajax-Whitby	THORNTON TS	0.26	0.088	2016 Peak
	WHITBY TS	0.7122	0.242	
	WILSON TS	19.48	1.69	
	TOTAL	**20.45**	**2.02**	
Parry Sound/Muskoka	No new contracted Distributed Generation			2020 Peak
Thunder Bay Northwest Ontario	BIRCH TS	0.536	0.001	2014 Peak
	FORT WILLIAM TS	0.293	0.000	
	MURILLO DS	0.326	0.000	
	NIPIGON DS	0.000	0.000	
	PORT ARTHUR TS	0.049	0.000	
	RED ROCK DS	1.000	0.001	
	TOTAL	**2.204**	**0.002**	
Windsor-Essex	No new contracted Distributed Generation			2018 Peak
West of Thunder Bay	AGIMAK DS	0.000	0.000	2014 Peak
	BARWICK TS	25.000	0.025	
	BURLEIGH DS	0.000	0.000	
	CLEARWATER BAY DS	0.000	0.000	
	CRILLY DS (STURGEON FALLS CGS)	0.000	0.000	
	DRYDEN TS	10.010	0.010	
	ETON DS	1.250	1.250	
	FORT FRANCES MTS	0.000	0.000	
	KEEWATIN DS	0.000	0.000	
	KENORA DS	0.000	0.000	
	KENORA MTS	0.045	0.000	
	MARGACH DS	0.000	0.000	
	MINAKI DS	0.000	0.000	
	MOOSE LAKE TS	0.010	0.000	
	NESTOR FALLS DS	0.000	0.000	
	SAM LAKE DS	0.000	0.000	
	SAPAWE DS	0.000	0.000	
	SHABAQUA DS	0.000	0.000	
	SIOUX NARROWS DS	0.000	0.000	
	VALORA DS	0.000	0.000	
	VERMILLION BAY DS	3.600	3.600	
	WHITERIVER DS	0.000	0.000	
	TOTAL	**39.915**	**4.885**	
North York/ GTA North	Holland TS	1.25	0.27	2017 Peak
	Armitage TS	0.61	0.13	
	Brown Hill TS	0.98	0.21	
	Buttonville TS	0.17	0.04	
	Markham 1 MTS	0.07	0.02	

	Markham 2 MTS	0.20	0.04	
	Markham 3 MTS	0.30	0.07	
	Markham 4 MTS	0.05	0.01	
	Richmond Hill MTS	0.17	0.04	
	Vaughan 1 MTS	0.33	0.07	
	Vaughan 2 MTS	0.07	0.02	
	Vaughan 3 MTS	0.31	0.07	
	Vaughan 4 MTS	-	-	
	TOTAL	**4.51**	**0.99**	
East Lake Superior	ECHO RIVER TS	0.00	0.00	2019 peak
	BATCHAWANA TS	0.00	0.00	
	GOULAIS BAY TS	0.00	0.00	
	PATRICK ST TS	0.00	0.00	
	ST. MARY'S MTS	0.00	0.00	
	TARENTORUS MTS	0.00	0.00	
	CHAPLEAU DS	0.00	0.00	
	DA WATSON TS	0.00	0.00	
	ANDREWS TS	0.00	0.00	
	MACKAY TS	0.00	0.00	
	NORTHERN AVE. TS	0.00	0.00	
	TOTAL	**0.00**	**0.00**	
Peterborough to Kingston	Ardoch DS	0.00	0.00	2018 peak
	Battersea DS	0.00	0.00	
	Belleville TS	0.00	0.00	
	Dobbin DS	0.00	0.00	
	Dobbin TS	0.00	0.00	
	Frontenac TS	0.50	0.005	
	Gardiner TS (T1/T2)	0.00	0.00	
	Gardiner TS (T3/T4)	0.00	0.00	
	Harrowsmith DS	0.00	0.00	
	Havelock TS	11.00	4.07	
	Hinchinbrooke DS	0.25	0.0025	
	Lodgeroom DS	0.00	0.00	
	Napanee TS	0.50	0.005	
	Northbrook DS	0.00	0.00	
	Otonabee TS	2.25	0.0225	
	Picton TS	2.00	0.00	
	Port Hope TS	3.60	0.036	
	Sharbot DS	0.00	0.00	
	Sidney TS	0.00	0.00	
	CTS	0.00	0.00	
	Total	**20.1**	**4.141**	

A.3 Other Initiatives

Other Electricity System Initiatives, as identified by the IESO, include:

Sub region	Other Electricity System Initiatives
Hamilton	The addendum to the Hamilton IRRP has been postponed due to updated asset condition information provided by Hydro One.
Ottawa	In 2019, in consultation with IESO staff, Hydro Ottawa submitted two proposals to Save On Energy's Local Program Fund (the "Fund"), a program application stream which allows LDCs to continue to design and deliver energy efficiency programs that serve the needs of their specific customers. Programs approved through the Fund must demonstrate cost-effectiveness based on the resulting net benefit when comparing the program investment (cost) against the provincial average avoided costs of providing electricity (benefit). So, while these investments will benefit ratepayer's province-wide, these offerings are also expected to help reduce the reliability risk due to heavily loaded stations in Kanata-Stittsville. The IESO approved both of Hydro Ottawa's proposed programs for delivery in 2020, which include the Kanata North Retrofit+ Program and the Kanata North Smart Thermostat Program. Both programs leverage the existing delivery infrastructure of current electricity and natural gas province-wide programs, which reduces administrative costs, streamlines customer experiences, and avoids market duplication and confusion. These local programs are an example of using system cost-effective energy efficiency to help address local system needs and can inform similar approaches in the future. It is forecasted that these two initiatives could combine to offset more than 3 MW or 50% of the near-term peak load growth in the Kanata North area. In doing so, these programs could help address the 60 MW of capacity need in the Kanata-Stittsville region and support reliable supply until a long-term solution for the area is implemented. The IESO has directed increased efforts and investment to the Ottawa area these past several years, to encourage the adoption of energy efficiency process and technologies in businesses and communities. As part of the 2021-2024 CDM Framework, the IESO was directed to deliver a new competitive 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. The IESO is currently working with Hydro Ottawa to develop a local initiative program procurement to begin targeting the incremental savings opportunities described above and previously highlighted in the 2020 Ottawa IRRP. As part of the as part of the 2021-2024 CDM Framework Mid-Term Review, the IESO is also reviewing new opportunities for CDM to be targeted to address regional or local needs and available tools to do so. As part of this effort, the IESO should continue to explore opportunities to target savings in the Ottawa and Peterborough to Quinte regions to help address these emerging bulk and regional system needs.

Windsor-Essex	The IESO continued planning for the Windsor-Essex region and surrounding area, with an IRRP addendum published in February 2022 and a West of London bulk study published in September 2021. The next planning cycle will begin in October 2022 with Hydro One leading the Needs Assessment. Development work for the recommended transmission reinforcements is ongoing. The IESO's Grid Innovation Fund and OEB's Innovation Sandbox issued a joint call for proposals to support research and demonstration projects that test the capabilities of distributed energy resources. One successful proponent included a proposed local electricity market in the Leamington area, proposed by Essex Powerlines, NODES, Essex Energy Corp., and Utilismart Corp. More information can be found at the IESO's website. The IESO continues offering an incentive for LED grow lights through the Retrofit program to help greenhouses in the Windsor-Essex and Chatham-Kent areas reduce their energy use.
Greenstone-Marathon / North of Dryden	The IESO is studying supply options to the Ring of Fire to inform government policy. This study will proceed in parallel with the ongoing IRRP.
East Lake Superior	The IESO initiated a Northeast Bulk planning study in 2021 to address the potential impact of high industrial load growth in this region on the bulk transmission system. Based on the conclusions of this study in relation to the impending need in the IRRP, the IESO is coordinating with the IRRP Working Group members on next steps to address this need.
West of Thunder Bay/ Northwest Ontario	The IESO will continue to monitor developments in the Region and provide the targeted in-service date for Phase 2 of the Waasigan Transmission Line Project. The IESO is in the process of updating and validating the mining demand forecast for Q1 2023 with an external consultant.
West GTA	The IESO and Ministry of Energy are conducting the NWGTA Transmission Corridor Identification Study to identify and protect a corridor of land for future transmission infrastructure.

APPENDIX B. PLANNING STATUS LETTERS

The TSC requires that letters be issued by the transmitter as per Section 3C.2.2 item (h):

(h) within 45 days of receipt of a request to do so, provide a letter to a licensed distributor or a licensed transmitter confirming the status of regional planning for a region, including any Regional Infrastructure Plan that is being developed for the region that includes the distributor's licensed service area or within which the requesting transmitter's transmission system is located, suitable for the purpose of supporting an application proposed to be filed with the Board by the distributor or requesting transmitter.

In compliance with this requirement, Hydro One has provided Planning Status Letters to the following LDCs since November 2021:

- Milton Hydro
- Hydro One Networks Inc. (Orillia Power Distribution Corporation service area)
- Hydro One Networks Inc. (formerly Peterborough Distribution Inc. service area)

Appendix J

Social Media Annual Report (2023)

2023 Lakeland Power Social Media Annual Report

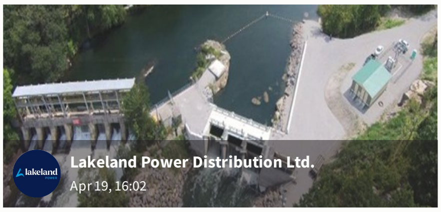
Jan 01 - Dec 31, 2023

Top posts

Lakeland Power Distribution Ltd.
Apr 05, 21:36

All power has now been restored in #Bracebridge. If you are still without power please call 1-888-282-7711. ^pa

7 reactions



Congratulations to our affiliate company, Bracebridge (Lakeland) Generation Ltd., on purchasing the Wasdell Falls generation station in Washago, Ontario. Full press release

6 reactions

To everyone doing what they do to deliver safe and reliable power, especially our Lakeland Power workers, we appreciate you! Lakeland Power is the local distribution

6 reactions

Posts table

DATE	MESSAGE	REACTIONS	COMMENTS ▲	SHARES
Lakeland Power… Dec 31, 14:00	New Year, New Electricity Plan? Find out if there's a plan that better suits your lifestyle. https://www.youtube.com/watch?v=aykuIVv_Dqk&list=PLgWect…	1	0	0
Lakeland Power… Dec 30, 14:00	It's #NationalBaconDay! Everything goes with bacon except stovetop fires. Remember always to keep your eyes on the stove. For more fire safety tips,…	1	0	0
Lakeland Power… Dec 29, 21:00	Looking for a New Year's resolution? Why not make it a goal to seal up the leaks around your windows and doors and make your home cozy and warm a…	1	0	0
Lakeland Power… Dec 29, 17:00	Day 12 #CyberSecurityTips - Learn more or see what you may have missed at https://www.getcybersafe.gc.ca/en/campaigns/cyber-safe-holidays…	1	0	0
Lakeland Power… Dec 28, 18:00	A reminder that our office is closed and will reopen on January 2, 2024. Happy Holidays from all of us at Lakeland Power! #SeasonsGreetings #OfficeClosu…	1	0	0
Lakeland Power… Dec 28, 17:00	Day 11 #CyberSecurityTips -Time for a puzzle? Check out this Cyber Safe Crossword at https://www.getcybersafe.gc.ca/en/resources/get-cyber-safe-…	0	0	0
Lakeland Power… Dec 27, 20:00	Feeling the Christmas Crunch? The Low-Income Energy Assistance Program can provide qualified households up to $500 ($600 for homes heated…	0	0	1
Lakeland Power… Dec 27, 17:00	Day 10 #CyberSecurityTips - HOLIDAY PASSWORD GENERATOR help at https://www.getcybersafe.gc.ca/en/resources/research/holiday-passphrase-gener…	2	0	0
Lakeland Power…	Day 9 #CyberSecurityTips - Take the CYBER SAFE CHECK-UP at https://www.getcybersafe.gc.ca/en/res…	1	0	0

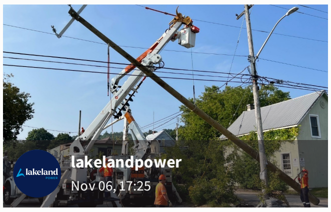
Posts

460
posts

Page reach

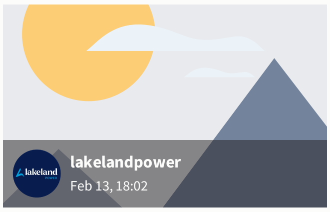
48,744
users

Top posts



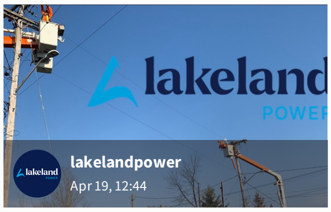
Ever wonder what a trade career looks like? Find out during National Skilled Trades and Technology Week. @Skills_Canada

13 likes



#DYK Lakeland Power provides yearly dividends to our municipalities to help our community thrive.

10 likes



To everyone doing what they do to deliver safe and reliable power, especially our Lakeland Power workers, we appreciate you!

10 likes

Posts

379
posts

Posts table

DATE ▲	MESSAGE	LIKES	COMMENTS	REACH
lakelandpower Dec 29, 17:01	Day 12 #CyberSecurityTips - Learn more or see what you may have missed at https://www.getcybersafe.gc.ca/en/campaigns/cyber-safe-holidays…	1	0	43
lakelandpower Dec 28, 18:01	A reminder that our office is closed and will reopen on January 2, 2024. Happy Holidays from all of us at Lakeland Power! #SeasonsGreetings #OfficeClosu…	1	0	35
lakelandpower Dec 28, 17:01	Day 11 #CyberSecurityTips -Time for a puzzle? Check out this Cyber Safe Crossword at https://www.getcybersafe.gc.ca/en/resources/get-cyber-safe-…	0	0	40

Tweets

435
tweets

Appendix J

		MESSAGE			
lakelandpower Dec 27, 17:01		Day 10 #CyberSecurityTips - HOLIDAY PASSWORD GENERATOR help at https://www.getcybersafe.gc.ca/en/resources/research/holiday-passphrase-gener…	0	0	55
lakelandpower Dec 26, 17:00		Day 9 #CyberSecurityTips - Take the CYBER SAFE CHECK-UP at https://www.getcybersafe.gc.ca/en/resources/research/take-get-cyber-safe-checkup…	0	0	47
lakelandpower Dec 26, 14:01		A reminder that our office is closed and will reopen on January 2, 2024. Happy Holidays from all of us at Lakeland Power! #SeasonsGreetings #OfficeClosu…	0	0	36
lakelandpower Dec 25, 17:00		Day 8 #CyberSecurityTips - DON'T GET HACKED! Even Santa is vulnerable https://www.getcybersafe.gc.ca/sites/default/files/2021-12/infog-santahacke…	0	0	91
		Day 7 #CyberSecurityTips -- 'Twas the Night before			

Page reach

90 connections

Top tweets

@LakelandPower
Feb 15, 23:03

#Outage in #Huntsville affecting approx 1976 homes and businesses. Crew dispatched. ETR TBD. For more info visit http://ow.ly/bc8G50MTEwt. #pwrout ^pa

18.72% engagement rate

@LakelandPower
Nov 25, 13:03

#Outage in #Bracebridge. Crew dispatched. ETR TBD. For more info visit https://outages.lakelandpower.on.ca/. #pwrout ^pa

13.67% engagement rate

@LakelandPower
Feb 16, 00:47

UPDATE: #Outage in #Huntsville affecting approx 1976 homes and businesses. Crew investigating. ETR TBD. For more info visit http://ow.ly/bc8G50MTEwt. #pwrout ^pa

10.59% engagement rate

Posts

3 posts

Tweets table

DATE	MESSAGE	RET…	QUO…	LIKES	REPL…	IMPR…	ENG…	% ENG…
@LakelandPower Mar 12, 13:01	Don't let en…	1	0	0	0	2,368	1	0.04%
@LakelandPower Feb 07, 22:02	#Tuesday Ti…	4	0	1	0	1,853	9	0.49%
@LakelandPower Feb 11, 23:00	Don't be fo…	0	0	1	0	1,835	1	0.05%
@LakelandPower Feb 28, 22:02	If you're…	0	0	1	0	1,519	1	0.07%
@LakelandPower Mar 01, 23:01	Do you un…	0	0	2	0	1,505	6	0.4%
@LakelandPower Feb 12, 15:01	Have you re…	1	0	0	0	896	2	0.22%
@LakelandPower Feb 15, 20:02	Do you kn…	0	1	1	0	854	1	0.12%
@LakelandPower Mar 25, 15:01	Celebrate…	3	1	0	0	851	7	0.82%
@LakelandPower	#DYK	1	0	2	0	832	8	0.96%

Top posts

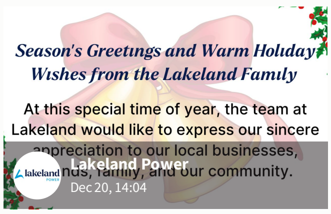
Lakeland Power
Nov 13, 15:23

Congratulations to our affiliate companies, Lakeland Generation and Lakeland Solutions, and SPEEDIER partner Georgian College on receiving 3rd party validation for the GHG Emission Reduction Reporting for Project SPEEDIER.

2 reactions

Happy Holidays from all of us at Lakeland Power! Please note that our office will be closed from December 22 at noon to January

0 reactions



Happy Holidays !

0 reactions

Report sources

Analytics

Facebook Pages

Lakeland Power Distribution Ltd.

Instagram Business

lakelandpower

Twitter

@LakelandPower

LinkedIn Pages

Lakeland Power