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

Pasquale Catalano
Director
Major Projects and Partnerships
C 647.616.8310
Pasquale.Catalano@HydroOne.com

BY EMAIL AND RESS

May 29, 2026

Mr. Ritchie Murray
Acting Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Mr. Murray,

EB-2026-0018 – Hydro One Networks Inc. Leave to Construct Application – Orléans Area Reinforcement – Application and Evidence

Pursuant to Section 92 of the Ontario Energy Board Act, 1998, (the “Act”), Hydro One Networks Inc. (“Hydro One”) seeks the Ontario Energy Board’s (“OEB”) approval for an Order or Orders granting leave to construct transmission facilities (“Orléans Area Reinforcement” or “Project”) in the Orléans area in eastern Ontario.

Additionally, pursuant to Section 97 of the Act, Hydro One seeks OEB approval for an Order granting approval of the forms of land use agreements offered or to be offered to affected landowners.

Hydro One is confirming that the documents filed in support of the referenced application do not include any personal information under the *Freedom of Information and Protection of Privacy Act (Ontario)* ("FIPPA") with respect to this Application. Any FIPPA related information in the Application has been redacted.

Furthermore, Hydro One is confirming that the System Impact Assessment report appendices, which contain confidential information, have been omitted from this Application. This approach is consistent with Chapter 4 (Section 4.3.6) of the OEB’s Filing Requirements for Electricity Transmission Applications.

An electronic copy of this Application and Evidence has been filed using the Board’s Regulatory Electronic Submission System.

Sincerely,

Pasquale Catalano

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LIST OF ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	Acronym or Abbreviation Expansion
A	Amperes
AACE	Association for the Advancement of Cost Engineering
AC/DC	Alternating Current / Direct Current
ACSS/TW	Aluminium-Conductor Steel-Supported, trapezoidal shaped cable
ACSR/TW	Aluminium-Conductor Steel-Reinforced, trapezoidal shaped cable
AFUDC	Allowance for Funds Used During Construction
BIL	Basic Insulation Level
C	Celsius
CIA	Customer Impact Assessment
Class EA	Class Environmental Assessment
CN Rail	Canadian National Railway
CSA	Canadian Standards Association
CT	Current Transformer
CTS	Customer Transformer Station
CVT	Capacitor Voltage Transformer
DESN	Dual Element Spot Network
DCF	Discounted Cash Flow
EA	Environmental Assessment
EPC	Engineering, Procurement and Construction
ESR	Environmental Study Report
GIB	Gas Insulated Bus
HQTE	Hydro-Québec TransÉnergie
HV	High Voltage
Hydro One	Hydro One Networks Inc. (HONI)
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
ISD	Investment Summary Document
ISOC	Integrated System Operating Center
JCT	Junction
kcmil	Kilo-circular mils *(unit of measure of the area of a wire with a circular cross section)*
km	Kilometer
kV	Kilovolt
kW	Kilowatt

Acronym or Abbreviation	**Acronym or Abbreviation Expansion**
LACP	Land Acquisition Compensation Principles
LTE	Long Term Emergency rating
LV	Low Voltage
m	Meter
MECP	Ministry of the Environment, Conservation and Parks
MTO	Ministry of Transportation (Ontario)
MTS	Municipal Transformer Station
MTU	Mobile Transformer Unit
MVA	Megavolt-ampere
MW	Megawatt
MWHR / MWH	Megawatt-hour
NCC	National Capital Commission
NERC	North American Electric Reliability Corporation
NGR	Neutral Grounding Resistor
NPCC	Northeast Power Coordinating Council
NPV	Net Present Value
OEB	Ontario Energy Board (the Board)
OMA	Operations, Maintenance and Administrative costs
PCT	Protection, Control and Telecommunications
PIN	Property Identification Number
PT	Potential Transformer
PV	Present Value
RIP	Regional Infrastructure Plan
ROE	Return on Equity
ROW	Right-of-Way
RPP	Regulated Price Plan
SCADA	Supervisory Control and Data Acquisition system
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
TWG	Technical Working Group
UTR	Uniform Transmission Rates
VT	Voltage Transformer

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B (the "**Act**");

AND IN THE MATTER OF an Application by Hydro One Networks Inc. ("**Hydro One**") pursuant to section 92 of the Act for an Order or Orders granting leave to construct transmission line facilities ("**Orléans Area Reinforcement Project**" or "**Project**") in the Orleans area of Ottawa;

AND IN THE MATTER OF an Application by Hydro One pursuant to section 97 of the Act for an Order granting approval of the forms of land use agreements offered or to be offered to affected landowners.

APPLICATION

1. The Applicant is Hydro One, a subsidiary of Hydro One Inc. The Applicant is an Ontario corporation with its head office in the City of Toronto. Hydro One carries on the business, among other things, of owning and operating transmission facilities within Ontario.

2. Hydro One hereby applies to the OEB pursuant to section 92 of the Act for an Order or Orders granting leave to construct a new 115 kV single-circuit transmission line, approximately 10 km in length, between Hawthorne TS and Orleans TS primarily within an existing transmission corridor in the Orleans area. As part of the Project, Hydro One will also construct an approximately 1 km section of 230 kV transmission line to connect into Hawthorne TS, which will enable the existing 115 kV single-circuit transmission line (H9A) to be reconfigured to operate at its rated 230 kV voltage and thereby provide the additional 230 kV supply capacity needed in the Orleans area. The total length of all transmission line facilities is approximately 11 km.

3. The Project is required to ensure sufficient 115 kV and 230 kV supply capacity to meet the growing electricity needs in the Orleans area in accordance with the recommendations from the regional planning process provided in **Exhibit H, Tab 1, Schedule 1**. The IESO further reaffirmed the need for the Project in their supplemental evidence provided for the purposes of this Application in **Attachment 1 of Exhibit B, Tab 3, Schedule 1.** The Project also aligns with Ontario's Integrated Energy Plan[1] which emphasizes the importance of taking action to ensure that the demand growth in eastern Ontario is not constrained by transmission capacity. Given the above, the Project has been identified as a non-discretionary development project in **Exhibit B, Tab 4, Schedule 1**.

4. An overview map of the area is provided in **Exhibit B, Tab 2, Schedule 1, Attachment 1,** and schematic diagrams of the proposed Project can be found at **Exhibit B, Tab 2, Schedule 1, Attachments 2 to 4**.

5. The forecast total capital cost of the Project transmission facilities is $99.9 million[2]. Details pertaining to these costs are provided at **Exhibit B, Tab 7, Schedule 1**.

6. The Project is not expected to have a material change in a typical residential customer's bill under the RPP (i.e., $0.01 per year using the 2026 OEB-approved Uniform Transmission Rates) as filed in **Exhibit B, Tab 9, Schedule 1**.

7. The 115 kV conductor selected by Hydro One to complete the Project has been predicated on Hydro One's commitment to minimize transmission line losses where feasible. Further information regarding the transmission line loss analysis for this Project is provided in **Exhibit B, Tab 5, Schedule 1**.

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[1] Energy for Generations, Ontario's Integrated Plan to Power the Strongest Economy in the G7 (June 2025) – p. 72
[2] There will be an additional $0.6M of OMA removal costs associated with constructing this Project.

8. The IESO has completed a Draft SIA. The final version is expected from the IESO shortly and will be filed upon receipt. The Draft SIA concludes that the Project is expected to have no material adverse impact on the reliability of the integrated power system and recommends that a *Notification of Conditional Approval for Connection* be issued. The IESO's Draft SIA is provided as **Exhibit F, Tab 1, Schedule 1, Attachment 1**.

9. Hydro One has completed a Draft CIA in accordance with Hydro One's connection procedures. A copy of the Draft CIA is provided as **Exhibit G, Tab 1, Schedule 1, Attachment 1**. The final version is expected to be completed shortly and will be filed upon completion. Hydro One will fulfill all requirements of the SIA and the CIA, and will obtain all necessary approvals, permits, licences, certificates, agreements, and rights required to construct the Project.

10. The Project is subject to the applicable Class EA process in accordance with the *Ontario Environmental Assessment Act.* On April 2, 2026, Hydro One filed the Final ESR[3] and Statement of Completion with the MECP.

11. The proposed in-service date for the Project is September 2029, assuming a construction commencement date of February 2027 and an OEB approval of this Application by January 2027. A project schedule with the aforementioned assumptions is provided at **Exhibit B, Tab 11, Schedule 1**.

12. New permanent land rights on properties between Hawthorne TS and Orleans TS will be required to accommodate the proposed transmission line facilities. The Project will require Hydro One to acquire land rights from 44 directly impacted properties.

13. Temporary rights for construction purposes will also be required at specific locations along the corridor. These rights will be negotiated and acquired as and when needed.

[3] Hydro One's Orleans Area Reinforcement Project Final ESR, dated April 2, 2026.

Further information regarding the real estate needs to complete this project are provided in **Exhibit E, Tab 1, Schedule 1**.

14. This Application is also seeking approval of the forms of the agreement offered, or to be offered, to affected landowners pursuant to section 97 of the Act. All voluntary property rights agreements will be in the form of an option agreement, and Hydro One will exercise these options and conclude the land rights agreements once it has received the OEB's Leave to Construct approval of the Project. These agreements are substantively consistent with the forms of agreement previously approved in prior Hydro One leave to construct proceedings. Any minor alterations from their last approval, should there be any, have all been explicitly identified in the Application. The forms of the applied-for agreements are found as attachments to **Exhibit E, Tab 1, Schedule 1**.

15. The Application is supported by written evidence which includes details of the Applicant's proposal for the transmission line facilities. The written evidence is prefiled and may be amended from time to time prior to the OEB's final decision.

16. Acronyms and abbreviations are used throughout the evidence and those acronyms and abbreviations are defined at **Exhibit A, Tab 1, Schedule 3**.

17. Based on the foregoing, and the information provided in the prefiled evidence, Hydro One submits that the Project is in the public interest.

18. The relief requested herein is required to ensure sufficient 115 kV and 230 kV supply capacity to meet the growing electricity needs in the Orleans area driven by long-term development and electrification trends. The Project meets the supply capacity need of the transmission system in accordance with the recommendations from the regional planning process and in alignment with the Integrated Energy Plan's direction.

19. The Project will enable more efficient use of existing assets and address constraints on the existing 115 kV system. By locating the new transmission line facilities within an existing transmission corridor, the Project reduces its land use footprint and minimizes impacts on both natural and socio-economic environments.

20. Furthermore, Hydro One is obligated to provide facilities required to maintain the reliability and integrity of its transmission system and reinforce or expand its transmission system as required to meet load growth in accordance with its Transmission License and the TSC. This Project is needed in order for Hydro One to satisfy this obligation.

21. Hydro One requests:
    a) An Order or Orders pursuant to section 92 of the Act granting leave to construct the Project;
    b) An approval of the forms of the agreement offered, or to be offered, to affected landowners pursuant to section 97 of the Act; and
    c) Such other relief as Hydro One may request or as the Board may direct.

22. Hydro One consents to the conditions outlined in the OEB's standard conditions of approval for electricity transmission leave to construct applications[4] for the Project. Furthermore, Hydro One consents to the OEB proceeding by way of a written hearing for this proceeding.

23. Hydro One requests that a copy of all documents filed with the OEB be served on the Applicant and the Applicant's counsel, as follows:

[4] Electricity Leave to Construct Issues List (December 16, 2025)

a) The Applicant:
Eryn Mackinnon
Regulatory Advisor
Hydro One Networks Inc.

Mailing Address:	7th Floor, South Tower 483 Bay Street Toronto, Ontario M5G 2P5
Telephone:	(437) 318-3700
Electronic access:	Regulatory@HydroOne.com

b) The Applicant's Counsel:
Mr. Richard J. King / Mr. Andrew Rintoul
Osler, Hoskin & Harcourt LLP

Mailing Address:	Suite 6200, 1 First Canadian Place 100 King Street West, P.O Box 50 Toronto, Ontario M5X 1B8
Telephone:	(416) 862-6626 / (416) 862-5963
Fax:	(416) 862-6666
Electronic access:	rking@osler.com / arintoul@osler.com

c) The Applicant's Counsel:
Laura Brazil
Assistant General Counsel
Hydro One Networks Inc.

Mailing Address:	8th Floor, South Tower 483 Bay Street Toronto, Ontario M5G 2P5
Telephone:	(416) 459-9817
Electronic access:	laura.brazil@hydroone.com

PROJECT OVERVIEW DOCUMENTS

Hydro One is seeking approval to construct and operate transmission line facilities between Hawthorne TS and Orleans TS consistent with the regional planning recommendations for the Orleans area and the IESO's evidence in support of the need for the Project as documented in **Attachment 1 of Exhibit B, Tab 3, Schedule 1**. The Project will strengthen the transmission system by expanding the 230 kV system while preserving the existing 115 kV system, increase the supply capacity to support demand in the Orleans area, and upgrade Orleans TS to a standard 230 kV DESN configuration, thereby improving the overall operability of the system and supply reliability to the area.

The following proposed facilities are subject to section 92 approval:

- Approximately 11 km of new transmission line facilities from Hawthorne TS to Orleans TS mainly along an existing transmission corridor between two parallel 230 kV double-circuit transmission tower lines (circuits D5A/H9A[1], and circuits A41T/A42T used for the interconnection with Hydro-Québec TransÉnergie).
- Terminal station modifications at Hawthorne TS and Orleans TS to accommodate the new transmission line facilities.
- Reconfiguration of the existing 115 kV transmission line (circuit H9A) to operate at its design rated capability of 230 kV. Once reconfigured, the transmission line will be renamed to circuit A25.

A map showing the geographic location of the existing facilities as well as schematic diagrams of the proposed facilities are provided in **Exhibit B, Tab 2, Schedule 1, Attachment 1** and **Exhibit B, Tab 2, Schedule 1, Attachments 2 to 4**, respectively.

The transmission system in the area requires reinforcement in order to ensure sufficient 115 kV and 230 kV supply capacity to meet the growing electricity needs in the Orleans area driven by long-term development and electrification trends. The Project will also

[1] Circuit H9A is rated for 230 kV but is currently configured to operate at 115 kV.

enable more efficient use of existing assets and address constraints on the existing 115 kV system and the 230/115 kV autotransformers at Hawthorne TS.

Further information on the overhead transmission line and the station facilities is provided below.

Overhead Transmission Line

There are two existing transmission circuits connecting Hawthorne TS and Orleans TS, one 115 kV circuit known as H9A and one 230 kV circuit known as D5A. Circuit H9A is designed and rated for 230 kV voltage although currently operated at 115 kV. The Orleans area is currently supplied from the 115 kV system through circuit H9A (supplying Orleans TS, Bilberry Creek TS, Navan DS, Wilhaven DS, Cumberland DS and the stations along 79M1) as well as circuit A2 (supplying Bilberry Creek TS).

With the completion of this Project, the existing 115 kV circuit (H9A) will be reconfigured to operate at 230 kV with a new 230 kV termination point at Hawthorne TS, thus expanding the 230 kV system to provide additional 230 kV supply between the two stations (i.e., Hawthorne TS and Orleans TS). Additionally, there will be a new 115 kV single-circuit transmission line installed within the existing transmission corridor to continue to supply the existing 115 kV system noted above, however, it will no longer be connected to Orleans TS. The proposed transmission line facilities between Hawthorne TS and Orleans TS will have a total route length of approximately 11 km and will traverse through the Orleans area of Ottawa. Further details on the physical design for the line and routing are provided in **Exhibit C, Tab 1, Schedule 1**. A schematic diagram showing the proposed transmission line facilities is provided at **Attachment 2 to this Schedule**.

Hawthorne TS Line Termination and Station Facilities

Hawthorne TS will require new assets within the station property to accommodate the reconfiguration of the existing 115 kV transmission line to 230 kV. These new assets include a new 230 kV line entrance structure, a new 230 kV gas insulated line from the line entrance structure to the existing 230 kV diameter, a new 230 kV breaker and associated equipment. The Project will also require modifications and additions to telecommunications, protection and control, SCADA, and metering systems at the station to provide protection, control, and monitoring of the new facilities, along with control capability to Hydro One's ISOC and status information to the IESO. Further details on the physical design for the station are provided in **Section 4.0 of Exhibit C, Tab 1, Schedule 1**. A schematic diagram showing the proposed configuration at Hawthorne TS is provided at **Attachment 3 to this Schedule**.

Orleans TS Line Termination and Station Facilities

Orleans TS will require new assets within the station property to enable the upgrade of Orleans TS to a standard 230 kV DESN configuration. These new assets include a new 230/27.6 kV transformer, 230 kV breakers and associated equipment; along with removal of the existing 115/27.6 kV transformer and associated equipment. The Project will also require modifications and additions to telecommunications, protection and control, SCADA, and metering systems at the station to provide protection, control, and monitoring of the new facilities, along with control capability to Hydro One's ISOC and status information to the IESO. Further details on the physical design for the station are provided in **Section 4.0 of Exhibit C, Tab 1, Schedule 1**. A schematic diagram showing the proposed configuration at Orleans TS is provided at **Attachment 4 to this Schedule**.

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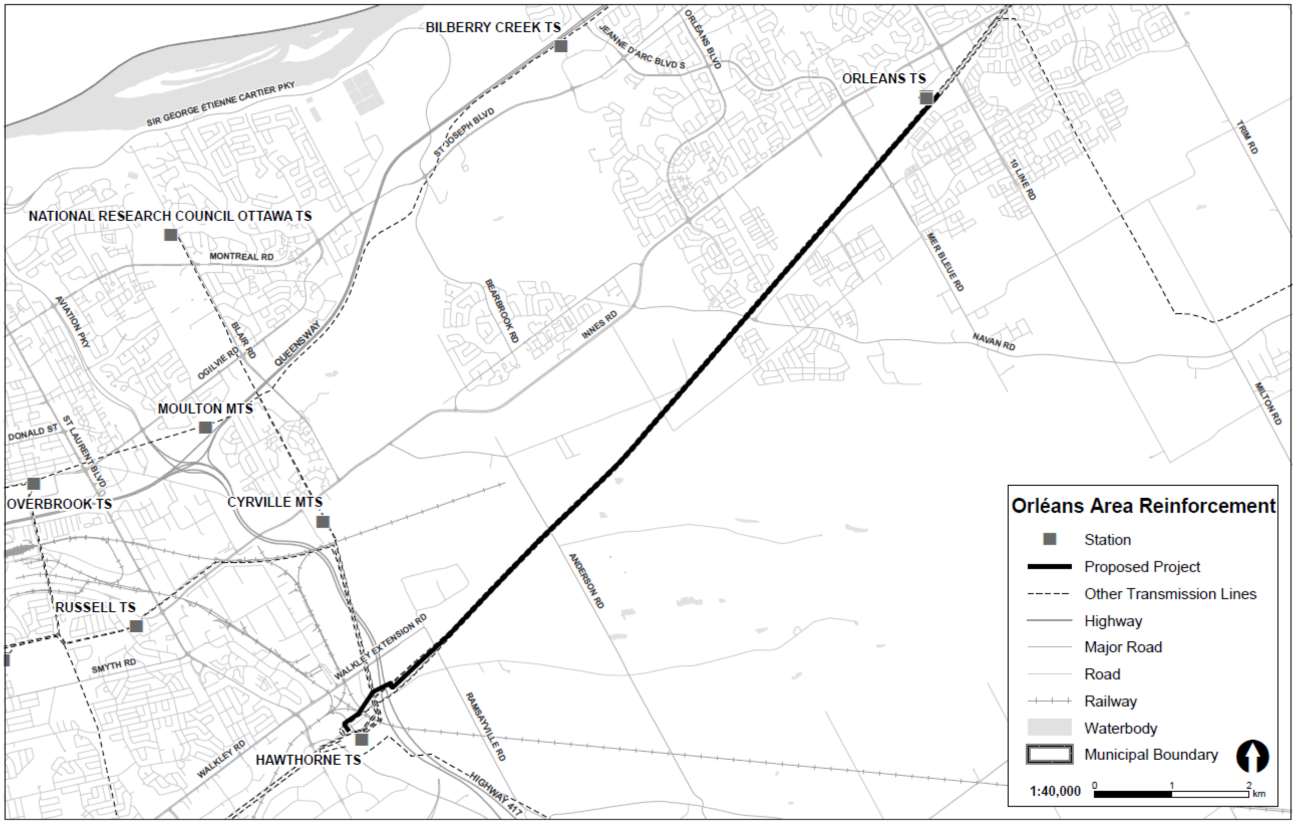
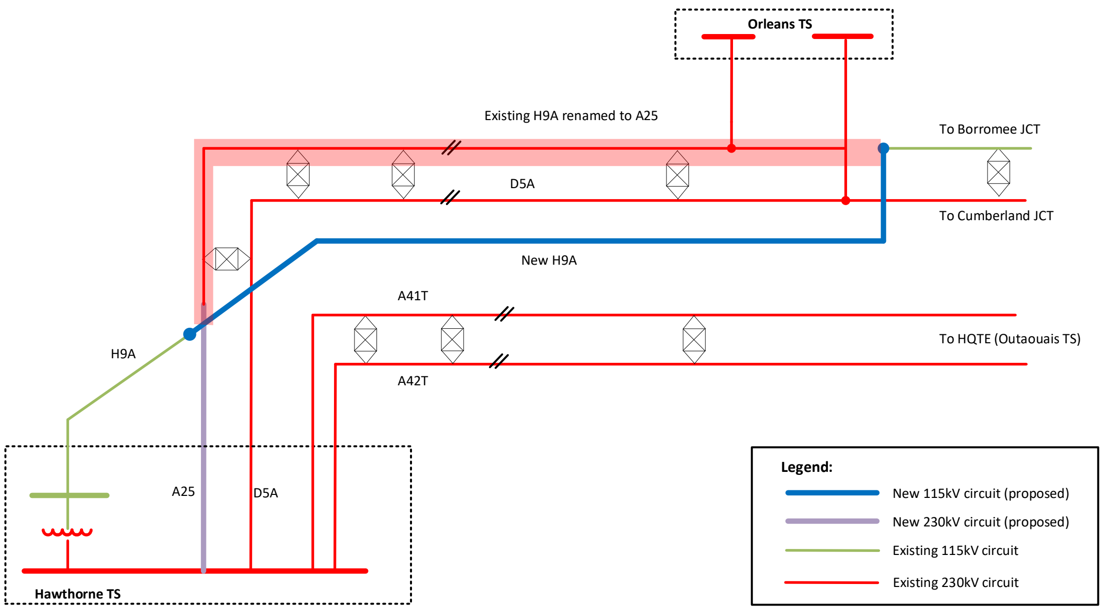
GENERAL AREA MAP



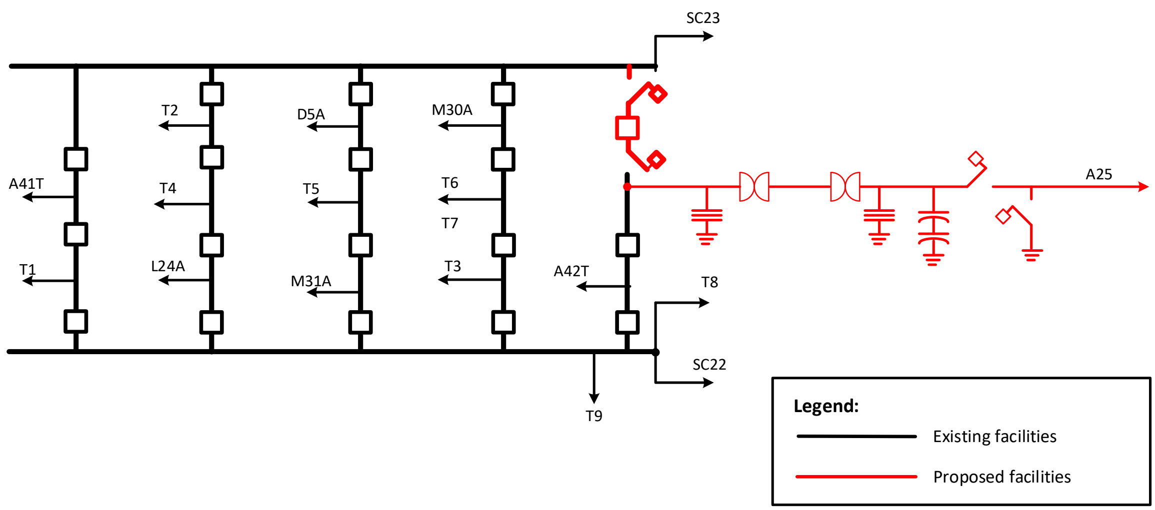
1 # PROPOSED FACILITIES:

2 # HAWTHORNE TS TO ORLEANS TS LINE SCHEMATIC DIAGRAM



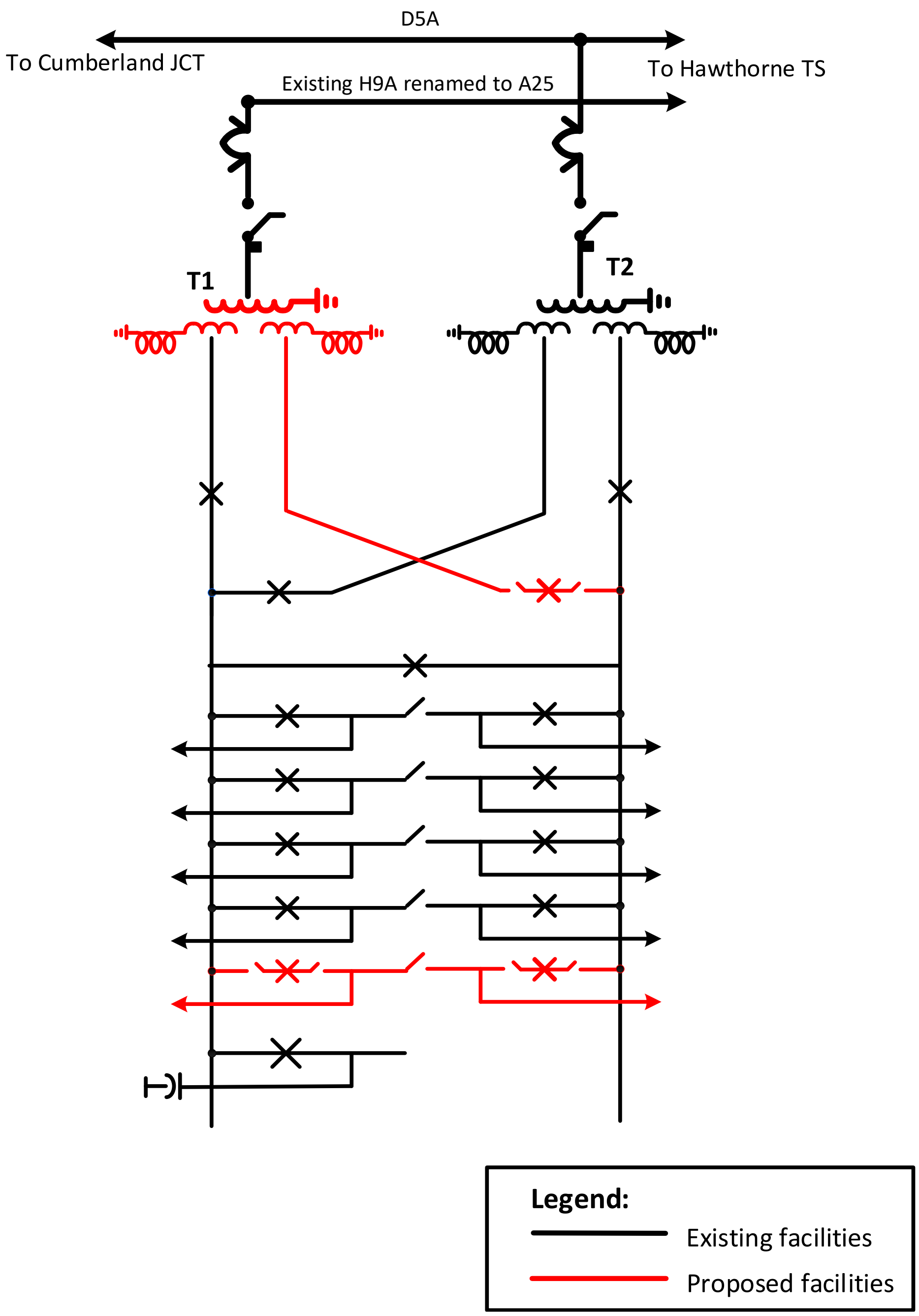
PROPOSED FACILITIES:

HAWTHORNE TS SIMPLIFIED SCHEMATIC DIAGRAM



1 **PROPOSED FACILITIES:**

2 **ORLEANS TS SIMPLIFIED SCHEMATIC DIAGRAM**



EVIDENCE IN SUPPORT OF NEED

The Project is needed to ensure sufficient 115 kV and 230 kV supply capacity to meet the growing electricity needs in the Orleans area driven by long-term development and electrification trends. This need is outlined in the regional planning reports included as attachments to **Exhibit H, Tab 1, Schedule 1**. The Project also aligns with the Ontario's Integrated Energy Plan[1] which emphasizes the importance of taking action to ensure that the demand growth – resulting from population increases, new residential development, and expanded electrification – in eastern Ontario is not constrained by transmission capacity.

As outlined in **Exhibit B, Tab 2, Schedule 1**, the Project will strengthen the transmission system and increase the supply capacity by expanding the 230 kV system while preserving the existing 115 kV system. The upgrade of Orleans TS to a standard 230 kV DESN configuration will shift load from the constrained 115 kV system to the 230 kV system and improve the overall operability of the system and supply reliability of the Orleans area. This will also enable more efficient use of existing assets and preserve the 115 kV system capacity to support future growth in the area.

Furthermore, Hydro One is obligated to provide facilities required to maintain the reliability and integrity of its transmission system and reinforce or expand its transmission system as required to meet load growth in accordance with its Transmission License and the TSC.[2] Not proceeding with this investment would result in Hydro One not satisfying this obligation.

For the purposes of this Application, the IESO has supplemented this need evidence with **Attachment 1 of this Schedule** titled "*Supplemental Evidence to Support the Need for the Orleans Area Reinforcement Project*" dated January 2026, which reaffirms the need

[1] Energy for Generations, Ontario's Integrated Plan to Power the Strongest Economy in the G7 (June 2025) – p. 72
[2] TSC, Section 3B.1

for the Project. Moreover, the IESO highlights the importance of proceeding with the Project, which offers a higher-capacity solution aligned with regional planning objectives and ensures the Orleans area is equipped to meet future electricity needs reliably and efficiently.

Supplemental Evidence to Support the Need for the Orleans Area Reinforcement Project

Independent Electricity System Operator

Connecting Today.
Powering Tomorrow.

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1. Executive Summary

The Independent Electricity System Operator ("IESO") is providing this report in support of the Leave-to-Construct ("LTC") application for the Orleans Area Reinforcement project (the "Project") in accordance with the requirements of the Ontario Energy Board's ("OEB") Chapter 4 of the Filing Requirements for Electricity Transmission Applications (the "Filing Requirements").

Section 4.3.2.3 of the Filing Requirements requires the applicant to provide evidence that identifies the recommended and planned transmission and non-wire projects in any regional plans and/or bulk plans that have "linkages and/or interdependencies to the applied-for transmission project." In the context of an LTC application, "linkages and/or interdependencies" refers to projects (including the Project) where the impact of one or more recommended and planned transmission and non-wire projects has the potential to affect the need for, or viability of, another such project.

The need and rationale for the Project are outlined in the 2023 Orleans Area Planning Study ("Orleans Study"), conducted by the Technical Working Group (TWG) between the conclusion of the second cycle[1] and the initiation of the third cycle[2] of the Greater Ottawa Area Integrated Regional Resource Plan (IRRP). The study assesses capacity, reliability, and end-of-life asset needs in the Orleans area expected to emerge over the next 20 years.

IESO's 2025 Ottawa Area IRRP reviewed the long-term electricity demand forecast for the Orleans area. The IRRP confirmed the need for increased supply capacity to support projected growth, particularly under high electrification scenarios. This confirmation reinforces the importance of proceeding with the Project, which offers a higher-capacity solution aligned with regional planning objectives and ensures the Orleans area is equipped to meet future electricity needs reliably and efficiently.

The purpose of this report is to provide that the OEB with the most up to date and complete information to assess the LTC application for the Project in the context of the recommendations that have been made. This report also provides evidence on the linkages and/or interdependencies between the Project and the additional reinforcements planned for the Greater Ottawa Area.

In conclusion, the IESO supports the Project as a necessary and timely development that complements broader regional planning efforts, aligns with provincial decarbonization goals, and ensures reliable electricity supply for the growing Orleans area and the Greater Ottawa Area.

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[1] 2020 Ottawa Area IRRP (link)
[2] 2025 Ottawa Area IRRP (link)

2. Background

2.1 Power System Planning in Ontario

The IESO is responsible for conducting independent planning for electricity generation, demand management, conservation and transmission in the Province of Ontario. In carrying out this mandate, the IESO undertakes planning activities to ensure that the province has, and will continue to have, an adequate and reliable supply of resources and transmission to meet Ontario's electricity needs.

The IESO's transmission planning generally consists of regional planning and bulk system planning. These are two separate but inter-related planning activities. Regional planning is carried out according to a regional planning process endorsed by the OEB. Regional planning produces plans that address system issues that are local in nature, within 21 planning regions covering the province. Bulk system planning is carried out by the IESO to address system issues which are more provincial in nature, such as the province-wide need for generation capacity, and transmission system solutions to enable transporting power reliably and economically across the province. Also covered are regulatory compliance studies and reporting requirements, such as those required by the North American Electric Reliability Corporation (NERC) reliability standards and the Northeast Power Coordinating Council (NPCC) criteria.

2.2 Regional Planning for Greater Ottawa Area

The second cycle of regional planning for Greater Ottawa, completed in 2020, identified two key needs: a station capacity requirement at Orleans TS and an asset renewal need at Bilberry Creek TS, including replacement of transformers and low-voltage circuit breakers. At the time, a recommendation was made to refurbish Bilberry Creek TS and construct two additional distribution feeders from the station to support load growth within Hydro Ottawa Limited's (HOL) distribution system.

However, since the release of the 2020 Ottawa Area IRRP, significant demand growth has occurred across the City of Ottawa. In response, the IRRP TWG initiated a re-evaluation of the original recommendations.

The re-evaluation of the Orleans Area was conducted between regional planning cycles. The Orleans Area Planning Study was developed to document the TWG's analysis and conclusions. The study was intended to inform transmitters and distributors within the working group, enabling them to proceed with long lead-time activities such as connection assessments, design engineering, cost estimating, and securing necessary approvals.

The third cycle of regional planning for the Greater Ottawa Area was completed in 2025. This IRRP identified growing electricity needs in the Ottawa area, driven by long-term development and electrification trends. To address these emerging needs, the IRRP emphasized the necessity of expanding supply capacity. The Project directly responds to that need by offering a solution that aligns with regional planning priorities and supports future growth in the area.

2.3 Summary of Recommendations in the Orleans Area Planning Study

The Orleans Study identified key issues in Orleans area:

- Bilberry Creek TS end-of-life need
- Orleans Area reliability needs
- Ottawa 115 kV system supply capacity needs

To address these issues, the Ottawa TWG recommended an integrated solution package:

- Decommission Bilberry Creek TS
- Build a new 230 kV circuit from Hawthorne TS to Orleans TS
- Upgrade Orleans TS to accommodate two 230 kV supply circuits
- New 230 kV supply station in Orleans
- Pursue up to 25 MW of additional system cost-effective energy efficiency in the Ottawa 115 kV system area over the 20-year planning horizon

The recommended solution increases supply capacity to the Orleans area, supporting long-term demand growth. It strengthens the transmission network by expanding the 230 kV system and upgrading Orleans TS, improving overall operability and reliability. It also avoids the need for reinvestments in aging infrastructure at Billberry Creek by shifting load from the constrained 115 kV system, preserving the 115 kV system capacity and enabling more efficient use of existing assets. In addition, it enhances local reliability by addressing voltage regulation issues and reducing the need for additional reactive support in surrounding areas.

The Project, which represents the core transmission component of this recommended package, reflects the TWG's consensus on a coordinated approach to meet both asset renewal and capacity needs in the Orleans area. It also facilitates enabling the necessary infrastructure upgrades and capacity additions to support the region's evolving electricity needs.

3. Linkages and Interdependencies with Regional Plans

From the IESO's perspective, the applied-for Orleans Area reinforcement project represents an important reinforcement that directly supports forecasted electricity demand growth in the Orleans area. It is a key component of the integrated electricity planning framework for the Greater Ottawa Area and is fully aligned with the recommendations of the recently published third cycle of the IRRP for Ottawa.

The project contributes meaningfully to the region's broader decarbonization objectives by enabling electrification, supporting the integration of clean energy resources, and reinforcing system reliability in a rapidly developing area. It is part of a well-coordinated set of transmission and non-wires initiatives identified through the IESO's regional planning process to address both capacity and asset renewal needs. The TWG, which includes the IESO, transmitters, and distributors, has carefully assessed and documented the interdependencies between this project and other planned developments. Together, these initiatives form a cohesive infrastructure strategy that supports long-term system resilience and regional growth.

This project, along with other recommended solutions in various parts of Ottawa, forms part of an integrated infrastructure strategy designed to support regional growth and enhance long-term system resilience. Through the coordinated efforts of the TWG, the timing, scope, and implementation of each initiative have been carefully aligned to ensure system-wide value and minimize planning and operational risks. These linkages and interdependencies are documented in the IRRP and supporting technical studies, demonstrating a comprehensive and collaborative approach to meeting the region's evolving electricity needs.

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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PROJECT CATEGORIZATION AND CLASSIFICATION

PROJECT CATEGORIZATION

Subsection 4.3.2.4 of the Board's Filing Requirements requires applicants to categorize projects as being either discretionary or non-discretionary. Non-discretionary project characteristics include:

a) mandatory requirements to satisfy reliability standards set by standards authorities including NPCC/NERC or the IESO;
b) a need to connect new load (of a distributor or large user) or new generation connection;
c) a need to address equipment loading or voltage/short circuit stresses when their rated capacities are exceeded;
d) a transmission project that the transmitter is required by its licence to develop and seek approvals for;
e) projects identified in a provincial government approved plan;
f) projects that are required to achieve provincial government objectives that are prescribed in governmental directives or regulations; and
g) priority transmission projects declared by Lieutenant Governor in Council order that the construction, expansion, or reinforcement of an electricity transmission line is needed as a priority project.

Based upon the above criteria, Hydro One submits that the Project is properly categorized as a non-discretionary project as it is being undertaken to increase supply capacity to support demand growth in accordance with recommendations from the regional planning process as described in **Exhibit B, Tab 3, Schedule 1**. These recommendations are consistent with the Integrated Energy Plan's direction[1] to ensure demand growth in eastern Ontario is not constrained by transmission capacity. Furthermore, the IESO supports the Project as necessary to ensure reliable supply for the growing Orleans area as documented in **Attachment 1 of Exhibit B, Tab 3, Schedule 1.**

[1] Energy for Generations, Ontario's Integrated Plan to Power the Strongest Economy in the G7 (June 2025) – p. 72

PROJECT CLASSIFICATION

Projects are classified into three groups based on their purpose.

- Development Projects, which most closely align with the System Service category as defined in Chapter 2 of the OEB Filing Requirements for Electricity Transmission Applications, are those which encompass modifications to ensure that a transmitter's system continues to meet operational objectives while addressing anticipated future customer electricity service requirements.

- Connection Projects, which most closely align with the System Access category as defined in Chapter 2 of the OEB Filing Requirements for Electricity Transmission Applications, are those which require modifications (including asset relocation) to a transmission system that a transmitter is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the transmission system.

- Sustainment Projects, which most closely align with the System Renewal category as defined in Chapter 2 of the OEB Filing Requirements for Electricity Transmission Applications, are those which involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the transmitter's system to provide customers with electricity services.

Based on the above criteria, the Project is a Development Project as the proposed transmission facilities provide for additional supply capacity to support demand in the Orleans area and maintain reliability and quality of electricity supply.

Categorization and Classification

<table>
<tr><td colspan="2" rowspan="2"></td><td colspan="2">Project Need</td></tr>
<tr><td>Non-Discretionary</td><td>Discretionary</td></tr>
<tr><td rowspan="3">Project Class</td><td>Development</td><td>X</td><td></td></tr>
<tr><td>Connection</td><td></td><td></td></tr>
<tr><td>Sustainment</td><td></td><td></td></tr>
</table>

COST BENEFIT ANALYSIS AND OPTIONS

1.0 ALTERNATIVES

As described in **Exhibit B, Tab 3, Schedule 1**, the Project was derived from the regional planning process to address the need for increased supply capacity to reliably support growth in the Orleans area, which was confirmed by the Greater Ottawa TWG in the regional planning reports[1] and reaffirmed in the IESO Report[2]. Based on this recommendation, Hydro One then proceeded to assess two alternative design options to address the need and provide additional 230 kV supply capacity to the Orleans area.

Alternative 1 – Modify the existing double-circuit transmission line towers, carrying the existing 115 kV circuit (H9A) and 230 kV circuit (D5A), to add an additional 230 kV circuit (A25) to the towers. The addition of the third circuit would have been achieved by replacing the arms on 115 kV circuit (H9A) side of the towers with longer arms that can support two circuits. The addition of the third circuit would have also required both tower and foundation reinforcements to support the additional circuit.

Alternative 2 *(the preferred alternative)* – Construct a new 115 kV single-circuit transmission line between Hawthorne TS and Orleans TS within an existing transmission corridor, thus enabling Hydro One to operate the existing 115 kV single-circuit transmission line (H9A) at its rated 230 kV voltage and provide the additional 230 kV supply capacity to the area. A new 115 kV circuit on the ROW was considered, instead of a 230 kV circuit, given that a 115 kV circuit can be designed using smaller structures which addresses the space limitation of the existing corridor.

Analysis and Recommendation

Both alternatives listed above would have addressed the need and increased the supply capacity to the Orleans area; however Alternative 1 was rejected as a viable alternative for the following technical reasons.

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[1] Exhibit H, Tab 1, Schedule 1, Attachments 1 and 2.
[2] Exhibit B, Tab 3, Schedule 1, Attachment 1

Firstly, the long span lengths between the existing towers and the proximity of the new 230 kV circuit (A25) on the same arm as the existing 115 kV circuit (H9A) would have introduced transmission line galloping. To address this problem, interphase spacers would be required to be installed on every span length. This mitigation, however, would not entirely eliminate transmission line galloping.

Secondly, the addition of the third circuit on the existing towers would have resulted in higher compression and uplift forces that would have exceeded the capacity of the existing tower foundations. The foundation reinforcements required to address this constraint may not be feasible in all locations along the corridor due to the terrain and subsurface conditions.

Finally, Alternative 1 would have been a more complex construction requiring outages to the existing circuits and the use of temporary bypass line arrangements. It would also result in more complex line maintenance due to the proximity of the existing 115 kV circuit (H9A) and the new 230 kV circuit (A25) supported by the extended arms on the same side of the towers and the use of the interphase spacers.

For these reasons, it was determined the only viable technical alternative was Alternative 2, the proposed Project. The IESO supports the need and recommended solution for the Project as documented in **Attachment 1 of Exhibit B, Tab 3, Schedule 1**.

2.0 TRANSMISSION LINE ALTERNATIVES

Conductor Size Alternative Analysis

Hydro One undertook an analysis of the conductor size alternatives that would; a) meet the supply capacity needs in the Orleans area, b) continue to maintain the interconnection power exchange capability, and c) would also be the optimal conductor size and rating, based on the expected load scenario in terms of line losses. The conductor alternatives evaluated were:

1. Alternative 1 – 1033.5 kcmil ACSS/TW conductor
2. Alternative 2 – 1443.7 kcmil ACSR/TW conductor

Analysis and Recommendation

All conductor alternatives listed above address the supply capacity needs of the area while maintaining the interconnection capability and ensuring a reliable supply to the Orleans area. The screening analysis, summarized in Table 1 below, considers the impact of line losses and was conducted in accordance with Hydro One's Transmission Line Loss Guideline.[3]

Table 1 - Screening Analysis

	Alt. #1 (1033.5 kcmil ACSS/TW)	**Alt. #2** (1443.7 kcmil ACSR/TW)
Net Capital Cost [4] ($M)	**$51.880**	**$52.945**
Losses at Peak Flow [5] (MW)	0.645	0.499
Losses at System Peak (MW)	0.645	0.499
Annual Revenue Costs ($M)	**$3.966**	**$4.046**
Annual Cost of Capital to Cover Losses ($M)	$0.106	$0.082
Annual Cost of Energy Losses ($M)	$0.300	$0.232
Annual Cost of Losses [6] ($M)	**$0.406**	**$0.314**
Total Annual Cost [7] ($M)	**$4.372**	**$4.360**

The screening analysis resulted in a change in alternative ranking and showed a similar Total Annual Cost, so a detailed 50-year NPV analysis was conducted. The NPV used a 5.65% discount rate, to evaluate which conductor alternative provided the best NPV result.

[3] As filed in proceeding EB-2023-0197, Exhibit I, Tab 2, Schedule 1, Attachment 1.
[4] Net Capital Cost is the total line cost to deliver the Project net of removals, as identified in Table 1 of Exhibit B, Tab 7, Schedule 1; and was based on a project definition equivalent to a Class 3 under the AACE estimate classification system for all alternatives.
[5] Losses based on 2039 forecast flows.
[6] Annual Cost of Losses is the summation of Annual Cost of Energy Losses (i.e. MWHR losses multiplied by the energy price) and the Annual Cost of Capital to Cover Losses (i.e. MW losses multiplied by Capacity Price).
[7] Total Annual Cost is the summation of Annual Revenue Costs and Annual Cost of Losses.

The NPV sensitivity analysis was done using varying values for the prices of energy (i.e., $53.16/MWHR, $120/MWHR) and a capacity price of $164,052MW consistent with Hydro One's Transmission Line Loss Guideline.

The results of the NPV sensitivity analysis are provided in Table 2 below.

Table 2 - NPV Sensitivity Analysis of Alternatives

	Alt. #1 (1033.5 kcmil ACSS/TW)	**Alt. #2** (1443.7 kcmil ACSR/TW)
Net Capital Cost [8] ($M)	**$51.880**	**$52.945**
Annual Losses (MWHR)	1,639	1,267
Losses at System Peak (MW)	0.645	0.499
Net Present Value ($M)		
Price	**Alt. #1** (1033.5 kcmil ACSS/TW)	**Alt. #2** (1443.7 kcmil ACSR/TW)
Energy Price of $53.16/MWHR and Capacity Price of $164,052/MW	-$49.28	**-$49.14**
Energy Price of $120/MWHR [9] and Capacity Price of $164,052/MW	-$51.90	**-$51.16**

The NPV analysis shows that Alternative 2 is the most economic alternative. Both alternatives meet the capacity needs for the area, but based on the analysis above, Alternative 2 is selected as the preferred and recommended alternative.

[8] Net Capital Cost is the total line cost to deliver the Project net of removals, as identified in Table 1 of Exhibit B, Tab 7, Schedule 1; and was based on a project definition equivalent to a Class 3 under the AACE estimate classification system for all alternatives.
[9] Note that for the purposes of this Application, and to address previous inquiries on same, Hydro One utilizes a sensitivity range that effectively doubles the current Ontario Energy Market Price to validate the results of the analysis.

QUANTITATIVE AND QUALITATIVE BENEFITS OF THE PROJECT

System benefits delivered by the Project are predominantly documented in the IESO's supplemental need evidence found at **Exhibit B, Tab 3, Schedule 1, Attachment 1** and the recently published regional planning report provided at **Exhibit H, Tab 1, Schedule 1, Attachment 2**.

The new transmission facilities and the way the Project will be delivered will ensure a reliable supply capacity to support growth in the Orleans area. The Project will also strengthen the transmission system by expanding the 230 kV system and shifting load from the constrained 115 kV system. Notably, shifting load from the constrained 115 kV system also alleviates pressure on aging infrastructure and enables more efficient use of the existing assets. Furthermore, by locating the new transmission line facilities within an existing transmission corridor, the Project reduces its land use footprint and minimizes impacts on both natural and socio-economic environments.

Hydro One also conducted an economic analysis to investigate ratepayer impacts with respect to transmission line losses. The NPV sensitivity analysis confirms that the 1443.7 kcmil ACSR/TW conductor is the most prudent conductor alternative to meet the needs of the Project. The results of that analysis are further discussed in **Exhibit B, Tab 5, Schedule 1**.

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APPORTIONING PROJECT COSTS AND RISKS

The estimated total capital cost of the Project is $99.9M[1]. The breakdown of these costs by line and station is shown below in Table 1 and Table 2, respectively.

Table 1 - Line Cost

	Estimated Cost ($000's)
Materials	$5,947
Labour	$8,956
Equipment Rental & Contractor Costs	$5,370
Sundry	$2,435
Contingencies	$4,535
Overhead [2]	$3,277
Allowance for Funds Used During Construction [3]	$4,884
Real Estate	$17,541
Total Line Work	**$52,945**

Table 2 - Station Cost

	Estimated Cost ($000's)
Materials	$11,068
Labour	$14,768
Equipment Rental & Contractor Costs	$8,294
Sundry	$776
Contingencies	$5,597
Overhead [2]	$3,180
Allowance for Funds Used During Construction [3]	$3,283
Real Estate	$0
Total Station Work	**$46,966**

The cost of the work provided above is predicated on the timing of the approval, design and construction activities documented in the Project Schedule at **Exhibit B, Tab 11, Schedule 1**.

[1] There will be an additional $0.6M of OMA removal costs associated with constructing this Project.
[2] Overhead Costs allocated to the Project are for corporate services costs. These costs are charged to capital projects through Hydro One's standard overhead capitalization rate (EB-2021-0110). As such they are considered "Indirect Overhead".
[3] AFUDC is calculated using the OEB's approved interest rate methodology (EB-2016-0160) to the forecast Project monthly cashflow and carrying forward closing balances from the preceding month.

The cost estimates provided in Tables 1 and 2 of this Schedule, and similarly the Project Schedule provided at **Exhibit B, Tab 11, Schedule 1**, are based on a project definition equivalent to a Class 3[4] under the AACE International (formerly the Association for the Advancement of Cost Engineering) estimate classification system[5].

The Project cost estimate was developed using a multi-faceted approach involving internal cost estimate tools and techniques, and a risk management model for the contingency allowance. This approach is in alignment with industry best practices.

1.0 RISKS AND CONTINGENCIES

As with most projects, there are risks associated with estimating costs. Hydro One's cost estimate includes an allowance for contingencies in recognition of these risks. Hydro One follows an industry established best practices methodology in developing the contingency utilizing a risk management model that includes both a qualitative and a quantitative risk analysis of identified risks to the Project.

The Project risks that predominantly contribute to the total contingency suggested for this Project include the following:

- **Permits, Approvals and Authorizations:** Risk of delays or cost escalation in securing all required approvals including leave to construct, and all necessary land rights, highway and rail crossing permits, and environmental approvals.
- **Procurement:** Risk to material lead times or material price increases that may cause schedule disruptions and increased cost.
- **Subsurface Conditions:** Risk of unforeseen underground obstructions or environmental conditions requiring additional mitigations that will have a cost impact and could delay the project progress.

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[4] An estimate range of -20%/+30%
[5] As per 96r-18 Cost Estimate Classification System – EPC Power Transmission Line Infrastructure Industries recommended practice document.

To mitigate these risks Hydro One has:

1. Established early and continuous engagement with all impacted stakeholders; as well as proactively submitted all regulatory applications, project permits and authorizations well in advance of the construction start of the Project, to ensure timely approvals, maintain transparent communication, and proactively address potential issues to mitigate the risk of project delays.
2. Initiated procurement of long lead materials (e.g., the transformer) in advance of the construction start date and established ongoing communication between Hydro One and the vendor.
3. Conducted preliminary studies and testing (e.g., boreholes, soil sampling, ground-penetrating radar) to identify subsurface conditions in order to develop implementation plans to address the risk if encountered during construction.

Cost contingencies that have not been included in the total contingency suggested for the Project, due to the unlikelihood or uncertainty of occurrence, include:

- Labour disputes;
- Safety or environmental incidents;
- Significant changes in costs and/or availability of materials outside the control of Hydro One; and
- Any other unforeseen and potentially significant event/occurrence.

2.0 COSTS OF COMPARABLE PROJECTS – TRANSMISSION LINE

The OEB Filing Requirements for *Electricity Transmission Applications, Chapter 4*, requires the Applicant to provide information about a cost comparable project constructed by the Applicant. Table 3 compares the line cost of the Project with three most recent comparable projects.

- **K4 Transmission Line Refurbishment Project between Kirkland Lake TS and Matachewan JCT**: Refurbish a 10 km line section of an existing 115 kV single-circuit wood pole transmission line (Circuit K4) that connects Kirkland Lake TS and Young–Davidson CTS. The project consisted of two sections (each 5 km in length): the first section included the replacement of conductors, all supporting wood pole

H-frame structures, and associated hardware along the existing circuit ROW; and the second section involved construction of a single-circuit transmission line on H-frame wood pole structures along a new ROW east of the existing line. Leave to construct approval for this project was provided under OEB docket EB-2023-0197.

- **X2Y Transmission Line Refurbishment Project between Magellan Aerospace CTS and IPB Bryson JCT**: Refurbish a 7.6 km line section of an existing 115 kV single-circuit wood pole transmission line (Circuit X2Y) between Magellan Aerospace CTS and IPB Bryson Junction. The project included the replacement of conductors, all supporting single-pole structures, and associated hardware. The project was not subject to leave to construct approval by the OEB.
- **A7L/R1LB, A6P Transmission Line Refurbishment Project between Alexander SS and Lakehead TS**: Refurbish a 103 km existing 115 kV double-circuit transmission line (Circuits A7L/ R1LB) on steel lattice tower structures between Lakehead TS and Alexander SS. Additionally, the scope included the refurbishment of approximately 15 km of an existing 115 kV single-circuit wood pole transmission line (Circuit A6P) between Alexander SS and Reserve Junction. Only the A6P circuit scope is being used as a comparator for the Orleans Area Reinforcement Project. The A6P work included the replacement of conductors, all supporting single-pole structures, and associated hardware. The project was not subject to leave to construct approval by the OEB.

These above-noted projects were selected as reasonable comparators because they share key characteristics with the Orleans Area Reinforcement Project, specifically they are all 115 kV single-circuit transmission lines utilizing primarily wood poles with similar line lengths between 7 km to 15 km and are geographically situated in a primarily rural area.

For the purposes of this comparison, Hydro One has excluded costs associated with real estate, the 230 kV line connection and temporary bypass/rider pole arrangements, along with variations in conductor size and structure types.

Hydro One has excluded the real estate costs from both the K4 and Orleans Area Reinforcement projects, as well as the 230 kV line connection work associated with the Orleans Area Reinforcement Project, because these elements are project-specific, and therefore not comparable across projects. Although real estate costs are excluded from the comparison provided in Table 3, the costs are reasonable as the real estate estimate for the Orleans Area Reinforcement Project is supported by independent third-party appraisals, and a contingency amount that is reserved for potential expropriation.

The adjustment for the variation in structure type was also made to account for the incremental cost to procure and install six composite poles along the Project's route which traverses NCC environmental sensitive lands; as well as to reflect the differences between single-pole and H-frame wood structures based on each specific-projects design for the K4 Transmission Line Refurbishment and Orleans Area Reinforcement projects. The use of composite poles was necessitated by a project-specific commitment made to the NCC as part of the Federal Land Use, Design, and Transaction Approval, and thus not applicable to the comparable projects. Similarly, adjustments were made to account for variations in conductor types to account for the larger ampacity requirements and the use of temporary bypass / rider pole arrangements required for the project-specific construction execution plans for the K4 Transmission Line Refurbishment and Orleans Area Reinforcement projects due to the load/outage constraints.

The variances in the unadjusted per/km cost to execute these projects is driven by the timing differences in the in-service date. Therefore, Table 3 has been adjusted to show comparable projects in 2029 dollars utilizing inflation values for future years consistent with the inflation parameters provided by the OEB.

When considering the adjusted comparable cost per km ratio for all other transmission line costs in Table 3, the Orleans Area Reinforcement Project exhibits slightly higher costs than comparable projects due to material differences in corridor conditions and execution constraints. Unlike the comparable projects that are primarily line refurbishment projects that utilize brownfield construction techniques (i.e. using the existing conductors to pull through and string the new conductor), the Orleans Area Reinforcement Project is new transmission construction that requires manual installation and tensioning of the conductor on the new structures.

In addition, the proposed new transmission line for the Orleans Area Reinforcement Project will be constructed between existing energized transmission circuits, significantly increasing construction complexity and safety requirements. All materials and stringing activities must be delivered and executed from the ground within constrained workspaces. Structure heights are also limited to maintain required electrical clearances, necessitating customized design and construction solutions. Further, the proposed new transmission line will traverse a densely developed urban area near Orleans TS and environmentally sensitive lands. Construction in urban locations necessitates extensive traffic and pedestrian control, temporary access removals, whereas in the environmentally sensitive lands accommodations of land-use and agricultural constraints and strict compliance with environmental protection requirements, including seasonal access restrictions through sensitive wetlands, are required. These conditions materially reduce construction productivity and increase overall project cost.

The K4 Transmission Line Refurbishment Project represents the most comparable benchmark in terms of overall scope and length (approximately 10 km); however, the execution even along the second 5 km section of new construction involved materially less complex conditions than that of the Orleans Area Reinforcement Project, noted above. Specifically the K4 Transmission Line Refurbishment Project experienced minimal urban congestion, fewer road and pedestrian crossings requiring contracted traffic control, limited interaction with protected wetlands, and fewer crossings of energized circuits. These differences directly affect constructability, risk exposure, and achievable construction efficiency.

When factoring in the above additional constraints, the cost of the Orleans Area Reinforcement Project is reasonable and consistent with the cost to complete comparable transmission line works, while ensuring execution of the Project is consistent with good utility practice to ensure safe, reliable system reinforcement in a highly constrained operating environment.

Table 3 - Costs of Comparable Line Projects

Project	**K4 Transmission Line Refurbishment Project (Line Cost)**	**X2Y Transmission Line Refurbishment Project (Line Cost)**	**A6P Transmission Line Refurbishment Project (Line Cost)**	**Orleans Area Reinforcement Project (Line Cost)**
Circuit Operating Designation	K4	X2Y	A6P	H9A
Voltage	115 kV	115 kV	115 kV	115 kV
Structure Type	Wood pole (H-Frame / Single-Pole)	Wood pole (Single-Pole)	Wood pole (Single-Pole)	Wood / Composite pole (H-Frame)
Single or Double Circuit	Single	Single	Single	Single
Conductor	997.2 kcmil ASCR/TW	411.4 kcmil ACSR/TW	411.4 kcmil ACSR/TW	1443.7 kcmil ACSR/TW
Location	Northern	Eastern	Northern	Eastern
Project Surroundings	Rural	Rural	Rural	Mostly Rural
In-Service Year	2024	2020	2020	2029
Estimate or Actual	Actual	Actual	Actual	Estimate
OEB-Approved Cost Estimate	$13.9M[6]	N/A[7]	N/A[7]	–
Total Cost	**$12,403K**	**$5,100K**	**$6,034K**	**$52,945K**
Less Adjustments:				
Real Estate	*$1,464K*	*N/A*	*N/A*	*$23,067K*[8]
230kV Line Connection	*N/A*	*N/A*	*N/A*	*$8,293K*
Incremental Cost for Structure Type Variations	*$1,085K*	*N/A*	*N/A*	*$6,243K*
Incremental Cost for Conductor Type Variations	*$190K*	*N/A*	*N/A*	*$751K*
Temporary Bypass / Rider Poles	*$156K*	*N/A*	*N/A*	*$2,338K*
Comparable Costs, before Escalation	**$9,508K**	**$5,100K**	**$6,034K**	**$12,253K**
Escalation Adjustment[9]	$1,862K	$1,852K	$2,191K	N/A
Total Adjusted Comparable Cost	**$11,370K**	**$6,952K**	**$8,225K**	*$12,253K*
Approximate Length	10km	7.6km	15km	10km
Unit Cost	**$1,137K/km**	**$915K/km**	**$548K/km**	**$1,225K/km**

[6] As per Section 92 leave to construct proceeding EB-2023-0197.
[7] This project was encompassed within a previous Hydro One revenue requirement application. The project was not subject to leave to construct approval by the OEB. Therefore, the specific investment does not have a discrete OEB approval to appropriately reference for the purposes of this comparison.
[8] This amount includes the direct real estate costs of $17,541K from Table 1 above plus contingency carried for expropriation, interest and overhead.
[9] Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.

COSTS OF COMPARABLE PROJECTS – STATIONS

For station cost comparison purposes, Table 4 below shows the cost, construction, and technical comparisons of the proposed line termination modifications at Hawthorne TS to the recently in-serviced work at Holland TS, at Beach TS and Chatham SS. Similarly, Table 5 below shows the cost, construction, and technical comparisons of the proposed work at Orleans TS to the recently in-serviced system renewal refurbishment projects at Parry Sound TS, King Edward TS, and Newton TS.

Unlike making a line comparison, where a per-kilometer cost can be derived, the same methodology and inferences for station work cannot always be achieved. There are several major differentiating factors, based on the unique site and station configuration, making individual station cost component comparisons difficult. Notwithstanding, the comparable projects selected are considered reasonable because the scope of work at Hawthorne TS is very similar when compared to other line termination modifications (i.e., installation of 230 kV breakers, switches, CVTs, etc.) as documented in Table 4; and likewise for Orleans TS when compared to system renewal refurbishment projects (i.e., replacement of 230 kV transformer and associated equipment) as documented in Table 5.

In Table 4, for the purposes of the comparison, Hydro One has excluded the costs associated with the Gas Insulated Bus work required at Hawthorne TS due to the uniqueness of this scope, and the AC/DC station service upgrades at Holland TS and Beach TS which are project-specific requirements and not comparable to the other projects. An adjustment was also made for the installation of buildings at Holland TS, Chatham SS, and Hawthorne TS, since these costs are not comparable across all projects and varies based on the size of the buildings and its locations.

In Table 5, for the purposes of the comparison, Hydro One has excluded the infrastructure costs associated with the new transformer installation (i.e., firewall, spill containment, drainage, or oil-water separator) at Orleans TS and Parry Sound TS, since these costs are not comparable to the other two projects (i.e., King Eward TS and Newton TS) in which no modification to these existing infrastructures were required based on the transformer design requirements. An adjustment was also made for the installation of breakers and its associated components at Orleans TS since this is a project-specific requirement and not comparable to the other projects.

Furthermore, Tables 4 and 5 have been adjusted to reflect the timing differences in the in-service date by showing comparable projects in 2029 dollars utilizing inflation values for future years consistent with the inflation parameters provided by the OEB.

When considering the adjusted comparable station costs in Tables 4 and 5, the comparable projects demonstrate that the estimate costs for Hawthorne TS and Orleans TS is consistent with the cost to complete comparable terminal station modification work and is reasonable.

Table 4 - Costs of Comparable Station Projects – Hawthorne TS

Project	Holland TS	Beach TS	Chatham SS	Hawthorne TS
Technical	Install (2) 230 kV circuit breakers, (10) switches, (3) CVTs, AC/DC Service Station, PCT building	Install (2) 230 kV circuit breakers, (6) switches, (3) CVTs, AC/DC Service Station	Install (3) 230 kV circuit breakers, (10) switches, (2) CVTs, PCT building	Install (1) 230 kV circuit breaker, (3) switches, (3) CVTs, (1) line entrance structure, GIB and associated equipment, (2) battery buildings
Location	Central	Southern	Southwest	Eastern
Project Surroundings	Rural	Urban/Industrial	Mostly rural	Urban/Industrial
In-Service Year	2017	2019	2024	2029
Estimate or Actual	Actual	Actual	Actual	Estimate
OEB-Approved Cost Estimate	N/A[10]	N/A[10]	$28.8M[11]	–
Total Cost	**$26,830K**	**$21,470K**	**$28,108K**	**$23,027K**
Less Adjustments:				
New gas insulated bus	*N/A*	*N/A*	*N/A*	*$11,707K*
New buildings	*$2,683K*	*N/A*	*$5,948K*	*$2,469K*
AC/DC Station Service	*$2,950K*	*$1,186K*	*N/A*	*N/A*
Comparable Costs, before Escalation	**$21,197K**	**$20,284K**	**$22,160K**	**$8,851K**
Escalation Adjustment[12]	$9,162K	$9,645K	$4,046K	N/A
Total Adjusted Comparable Cost	**$30,359K**	**$29,929K**	**$26,206K**	**$8,851K**

[10] This project was encompassed within a previous Hydro One revenue requirement application. The project was not subject to leave to construct approval by the OEB. Therefore, the specific investment does not have a discrete OEB approval to appropriately reference for the purposes of this comparison.
[11] As per Section 92 leave to construct proceeding EB-2022-0140.
[12] Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.

1 **Table 5 - Costs of Comparable Station Projects – Orleans TS**

Project	Parry Sound TS	King Edward TS	Newton TS	Orleans TS
Technical	Replace (2) 230/44 kV transformers, (1) 230kV switch, (3) 230kV CVTs, (12) surge arrestors, (3) 44 kV switches, (2) NGRs, spill containment, drainage, and oil/water separator	Replace (1) 115/13.8 kV transformer, (3) 115 kV switch, (6) surge arrestors, (1) VT, (2) NGRs, PCT upgrades	Replace (1) 115/13.8 kV transformer (2) 115 kV switches, (6) surge arrestors, (2) NGRs, PCT upgrades.	Replace (1) 115kV/27.6 kV transformer with a new 230/27.6 kV unit and new firewall, (3) 230 kV CVTs, (3) 27.6 kV circuit breaker, (9) 27.6 kV switches, (9) surge arresters, (2) neutral reactors, (3) CT/PTs, PCT upgrades
Location	Central	Eastern	Southwest	Eastern
Project Surroundings	Rural	Urban	Urban	Urban
In-Service Year	2023	2021	2021	2029
Estimate or Actual	Actual	Actual	Actual	Estimate
OEB-Approved Cost Estimate	N/A[13]	N/A[13]	N/A[13]	–
Total Cost	**$24,156K**	**$16,996K**	**$11,819K**	**$23,939K**
Less Adjustments:				
New transformer associated facilities[14]	*$1,550K*	*N/A*	*N/A*	*$1,547K*
Installation of breakers & associated components	*N/A*	*N/A*	*N/A*	*$1,800K*
Comparable Costs, before Escalation	**$22,606K**	**$16,996K**	**$11,819K**	**$20,592K**
Escalation Adjustment[15]	$5,597K	$5,568K	$3,820K	N/A
Total Adjusted Comparable Cost	**$28,203K**	**$22,564K**	**$15,639K**	**$20,592K**

[13] This project was encompassed within a previous Hydro One revenue requirement application. The project was not subject to leave to construct approval by the OEB. Therefore, the specific investment does not have a discrete OEB approval to appropriately reference for the purposes of this comparison.
[14] This includes facilities such as: firewalls, spill containment, drainage, and/or oil/water separator
[15] Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.

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CONNECTION PROJECTS REQUIRING NETWORK REINFORCEMENT

This is not a connection project. Facilities being upgraded as part of this Project are limited to those discussed in the details of the work being undertaken in **Exhibit C, Tab 1, Schedule 1.**

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TRANSMISSION RATE IMPACT ASSESSMENT

1.0 ECONOMIC FEASIBILITY

The Project costs will be included in the network, line and transformation connection pools for cost classification purposes and not allocated to any individual customer. See **Exhibit B, Tab 2, Schedule 1**, for information on the proposed work. No customer contribution is required for the Project.

A 25-year discounted cash flow analysis of the network pool work demonstrates that based on the estimated initial cost of $23.4 million[1], plus the assumed impact on the future capital cost allowance, Hydro One's corporate income tax and approximately $6.7 million in average annual incremental network revenue utilizing the 2026 UTR over a 25-year evaluation period, this rate pool will have a positive net present value of $43.2 million as seen in Tables 1 and 2 below.

A 25-year discounted cash flow analysis of the line connection pool work demonstrates that based on the estimated initial cost of $52.9 million[2], plus the assumed impact on the future capital cost allowance, Hydro One's corporate income tax and approximately $1.1 million in average annual incremental line connection revenue utilizing the 2026 UTR over a 25-year evaluation period, this rate pool will have a negative net present value of $39.3 million as seen in Tables 3 and 4 below.

A 25-year discounted cash flow analysis of the transformation connection pool work demonstrates that based on the estimated initial cost of $24.2 million[3], plus the assumed impact on the future capital cost allowance, Hydro One's corporate income tax and approximately $1.4 million in average annual incremental transformation connection

[1] Initial network costs of $23.4 million include $23.0 million of up-front capital costs plus $0.4 million cost of removals.
[2] Initial line connection costs of $52.9 million include $52.9 million of up-front capital costs plus $0 million cost of removals.
[3] Initial transformation connection costs of $24.2 million include $23.9 million of up-front capital costs plus $0.3 million cost of removals.

revenue utilizing the 2026 UTR over a 25-year evaluation period, this rate pool will have a negative net present value of $8.9 million as seen in Tables 5 and 6.

2.0 COST RESPONSIBILITY

The Project will strengthen the transmission system by expanding the 230 kV system while preserving the existing 115 kV system, increase the supply capacity to support demand in the Orleans area, and upgrade Orleans TS to a standard 230 kV DESN configuration, thereby improving the overall operability of the system and supply reliability to the area. The Project will also enable more efficient use of existing assets and address constraints on the existing 115 kV system and the 230/115 kV autotransformers at Hawthorne TS.

The Project is not associated with any specific load increase or customer load application, rather these facilities are required to ensure sufficient 115 kV and 230 kV supply capacity to meet the growing electricity needs in the Orleans area in accordance with the recommendations from the regional planning process, thus a capital contribution will not be required.

Network Pool

Hawthorne TS is an existing network station, hence the proposed transmission facilities to be installed at this station are to be included in the Network Pool. No customer capital contribution is required, consistent with provisions of Section 6.3.5 of the TSC.

Line Connection Pool

The existing 115 kV transmission line (circuit H9A) is classified as a multi-purpose (dual function line) asset. As stated in **Exhibit B, Tab 1, Schedule 1**, the Project involves constructing a new 115 kV transmission line within the existing transmission corridor in order to enable the existing 115 kV transmission line (circuit H9A) to be reconfigured to operate at its rated 230 kV voltage and thereby provide the additional 230 kV supply capacity to the Orleans area in accordance with the recommendations from the regional planning process. The new 115 kV transmission line facilities will continue to supply the existing 115 kV system and thus will remain classified as a multi-purpose (dual function line) asset. The transmission line facilities reconfigured to operate at 230 kV (circuit A25) are to be included in the Line Connection Pool. This work is not attributable to any specific request by a customer, as identified above, thus a capital contribution will not be required.

Transformation Connection Pool

The existing Orleans TS is a transformation connection asset. The conversion of Orleans TS to a standard 230 kV DESN station will require the replacement of one existing 115/27.6 kV transformer with a new 230/27.6 kV transformer and other associated equipment. These facilities and the associated cost are to be included in the Transformation Connection Pool. This work is not attributable to any specific request by a customer, as identified above, thus a capital contribution will not be required.

3.0 RATE IMPACT ASSESSMENT

The analysis of the network, line and transformation connection pool rate impacts has been carried out on the basis of Hydro One's transmission revenue requirement for the year 2026, and the 2026 approved Ontario Transmission Rate Schedules. The network, line and transformation connection pool revenue requirements would be affected by the Project based on the project cost allocation.

Network Pool

Based on the estimated initial cost of $23.4 million and the associated network pool incremental cash flows, there will be a change in the network pool revenue requirement once the Project's impacts are reflected in transmission rate base at the projected in-service date of September 30, 2029. The 2026 OEB-approved rate of $6.39 per kW/month slightly decreases to $6.38 per kW/month in the first year and then decreases again to $6.37 per kW/month in the 8th year over a 25-year time horizon. The detailed analysis illustrating the calculation of the incremental network revenue and rate impact is provided in Tables 7 and 8 below.

Line Connection Pool

Based on the estimated initial cost of $52.9 million and the associated line pool incremental cash flows, there will be a change in the line pool revenue requirement once the Project's impacts are reflected in transmission rate base at the projected in-service date of September 30, 2029. The 2026 OEB-approved rate of $1.03 per kW/month slightly increases to $1.04 per kW/month in the first year over a 25-year time horizon. The detailed analysis illustrating the calculation of the incremental line revenue and rate impact is provided in Tables 9 and 10 below.

Transformation Connection Pool

Based on the estimated initial cost of $24.2 million and the associated transformation pool incremental cash flows, there will be a change in the transformation pool revenue requirement once the Project's impacts are reflected in transmission rate base at the projected in-service date of September 30, 2029. The 2026 OEB-approved rate of $3.47 per kW/month slightly increases to $3.48 per kW/month in the first year then decreases back to $3.47 per kW/month in the 14th year over a 25-year time horizon. The detailed analysis illustrating the calculation of the incremental transformation revenue and rate impact is provided in Tables 11 and 12 below.

<u>Impact on Typical Residential Customer</u>

Based on the load forecast, initial capital costs and ongoing maintenance costs, adding the costs of the required facilities to the network, line and transformation connection pools will cause no material change to a typical residential customer's bill under the RPP. The table below shows this result for a typical residential customer who is under the RPP, utilizing the maximum impact by rate pool, regardless of year.

Table 1 - Rate Impact on Typical Residential Customer Bill

A. Typical monthly bill	$168.81 per month
B. Transmission component of monthly bill	$18.08 per month
C. Line Connection Pool share of Transmission component	$1.74 per month
D. Transformation Connection Pool share of Transmission component	$5.85 per month
E. Network Connection Pool share of Transmission component	$10.49 per month
F. Impact on Line Connection Pool Provincial Uniform Rates	0.97%
G. Impact on Transformation Connection Pool Provincial Uniform Rates	0.29%
H. Impact on Network Connection Pool Provincial Uniform Rates	-0.31%
I. Increase in Transmission costs for typical monthly bill (C x F + D x G + E x H)	$0.00 per month or $0.01 per year
J. Net increase on typical residential customer bill (E / A)	0.00%

1 **Table 1 - Net Present Value, Network Pool page 1**

Date:	27-Apr-26
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Network Pool - Estimated cost

Facility Name:	Hawthorne x Orleans New 230kV TL
Description:	Hawthorne x Orleans New 230kV TL
Customer:	

			In-Service Date	<-------		Project year ended - annualized from In-Service Date			-------->						
		Month	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30
		Year	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
			0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast															
Load Forecast (MW)				64.2	69.5	72.2	74.3	76.3	78.4	80.7	82.7	84.7	86.6	88.4	90.5
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				64.2	69.5	72.2	74.3	76.3	78.4	80.7	82.7	84.7	86.6	88.4	90.5
Tariff Applied ($/kW/Month)				6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39
Incremental Revenue - $M				4.9	5.3	5.5	5.7	5.9	6.0	6.2	6.3	6.5	6.6	6.8	6.9
Removal Costs - $M			(0.4)												
On-going OM&A Costs - $M			0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M				(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M			(0.4)	4.8	5.2	5.4	5.6	5.8	5.9	6.1	6.2	6.4	6.5	6.7	6.8
Income Taxes			0.1	(1.0)	(0.9)	(1.0)	(1.1)	(1.2)	(1.2)	(1.3)	(1.4)	(1.4)	(1.5)	(1.5)	(1.6)
Operating Cash Flow (after taxes) - $M			(0.3)	3.8	4.3	4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.0	5.1	5.2
		Cumulative PV @ 5.65%													
PV Operating Cash Flow (after taxes) - $M	**(A)**	**66.1**	**(0.3)**	**3.7**	**4.0**	**3.9**	**3.7**	**3.6**	**3.5**	**3.3**	**3.2**	**3.1**	**3.0**	**2.9**	**2.8**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(19.9)												
- Overheads			(1.5)												
- AFUDC			(1.5)												
Total upfront capital expenditures			**(23.0)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(23.0)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**0.1**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	**(B)**	**(22.9)**	**(22.9)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**43.2**	**(23.2)**	**(19.5)**	**(15.5)**	**(11.6)**	**(7.9)**	**(4.3)**	**(0.9)**	**2.5**	**5.7**	**8.8**	**11.8**	**14.6**	**17.4**

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**
Discount Rate - %		**5.65%**
		$M
PV Incremental Revenue		87.1
PV OM&A Costs		(0.9)
PV Municipal Tax		(1.0)
PV Income Taxes		(22.6)
PV CCA Tax Shield		3.6
PV Capital - Upfront	(23.0)	
Add: PV **Capital Contribution**	**0.0**	(23.0)
PV Capital - On-going		0.0
PV Working Capital		(0.0)
PV Surplus / (Shortfall)		**43.2**
Profitability Index*		**2.9**

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Other Assumptions

In-Service Date:	30-Sep-29
Payback Year:	2036
No. of years required for payback:	7

Table 2 - Net Present Value, Network Pool, page 2

Date:	27-Apr-26
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Network Pool - Estimated cost

Facility Name:	Hawthorne x Orleans New 230kV TL
Description:	Hawthorne x Orleans New 230kV TL
Customer:	

	<------- Project year ended - annualized from In-Service Date -------->												
Month	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30
Year	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast													
Load Forecast (MW)	92.6	94.5	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	94.9
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	92.6	94.5	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	94.9
Tariff Applied ($/kW/Month)	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39
Incremental Revenue - $M	7.1	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
Removal Costs - $M													
On-going OM&A Costs - $M	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Municipal Tax - $M	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M	7.0	7.1	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Income Taxes	(1.7)	(1.7)	(1.7)	(1.8)	(1.8)	(1.8)	(1.8)	(1.8)	(1.8)	(1.8)	(1.8)	(1.8)	(1.8)
Operating Cash Flow (after taxes) - $M	5.3	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.3	5.3	5.3
PV Operating Cash Flow (after taxes) - $M (A)	2.7	2.6	2.4	2.3	2.2	2.1	1.9	1.8	1.7	1.6	1.5	1.5	1.4
Capital Expenditures - $M													
Upfront - capital cost before overheads & AFUDC													
- Overheads													
- AFUDC													
Total upfront capital expenditures													
On-going capital expenditures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures													
Total capital expenditures - $M													
Capital Expenditures - $M													
PV CCA Residual Tax Shield - $M													
PV Working Capital - $M													
PV Capital (after taxes) - $M (B)													
Cumulative PV Cash Flow (after taxes) - $M (A) + (B)	20.1	22.7	25.1	27.4	29.6	31.7	33.6	35.4	37.2	38.8	40.4	41.8	43.2

Table 3 - Net Present Value, Line Connection Pool, page 1

Date:	27-Apr-26
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Hawthorne x Orleans New 230kV TL
Description:	Hawthorne x Orleans New 230kV TL
Customer:	

			In-Service Date	<-------	Project year ended - annualized from In-Service Date	-------->									
		Month	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30
		Year	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
			0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast															
Load Forecast (MW)				64.2	69.5	72.2	74.3	76.3	78.4	80.7	82.7	84.7	86.6	88.4	90.5
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				64.2	69.5	72.2	74.3	76.3	78.4	80.7	82.7	84.7	86.6	88.4	90.5
Tariff Applied ($/kW/Month)				1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03
Incremental Revenue - $M				0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.1	1.1	1.1
Removal Costs - $M			0.0												
On-going OM&A Costs - $M			0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M				(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Net Revenue/(Costs) before taxes - $M			0.0	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.9	0.9	0.9
Income Taxes			0.0	0.2	0.6	0.5	0.4	0.4	0.3	0.3	0.2	0.2	0.1	0.1	0.1
Operating Cash Flow (after taxes) - $M			0.0	0.8	1.2	1.2	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0
		Cumulative PV @ 5.65%													
PV Operating Cash Flow (after taxes) - $M	**(A)**	**13.5**	**0.0**	**0.8**	**1.1**	**1.0**	**0.9**	**0.9**	**0.8**	**0.7**	**0.7**	**0.6**	**0.6**	**0.6**	**0.5**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(44.8)												
- Overheads			(3.3)												
- AFUDC			(4.9)												
Total upfront capital expenditures			**(52.9)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(52.9)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**0.2**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	**(B)**	**(52.8)**	**(52.8)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(39.3)**	**(52.8)**	**(52.0)**	**(50.9)**	**(49.9)**	**(48.9)**	**(48.1)**	**(47.3)**	**(46.6)**	**(45.9)**	**(45.3)**	**(44.7)**	**(44.1)**	**(43.6)**

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**
Discount Rate - %		**5.65%**
		$M
PV Incremental Revenue		14.0
PV OM&A Costs		(0.5)
PV Municipal Tax		(2.4)
PV Income Taxes		(2.9)
PV CCA Tax Shield		5.5
PV Capital - Upfront	(52.9)	
Add: PV **Capital Contribution**	**0.0**	(52.9)
PV Capital - On-going		0.0
PV Working Capital		(0.0)
PV Surplus / (Shortfall)		(39.3)
Profitability Index*		**0.3**

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Other Assumptions

In-Service Date:	30-Sep-29
Payback Year:	2054
No. of years required for payback:	25

Table 4 - Net Present Value, Line Connection Pool, page 2

Date:	27-Apr-26
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Hawthorne x Orleans New 230kV TL
Description:	Hawthorne x Orleans New 230kV TL
Customer:	

<------- Project year ended - annualized from In-Service Date -------->

	Month	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30
	Year	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
		13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast														
Load Forecast (MW)		92.6	94.5	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	94.9
Load adjustments (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		92.6	94.5	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	94.9
Tariff Applied ($/kW/Month)		1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03
Incremental Revenue - $M		1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Removal Costs - $M														
On-going OM&A Costs - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M		(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Net Revenue/(Costs) before taxes - $M		0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Income Taxes		0.0	0.0	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Operating Cash Flow (after taxes) - $M		1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8
PV Operating Cash Flow (after taxes) - $M	**(A)**	**0.5**	**0.5**	**0.4**	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	**(B)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(43.1)**	**(42.6)**	**(42.2)**	**(41.8)**	**(41.5)**	**(41.1)**	**(40.8)**	**(40.5)**	**(40.2)**	**(40.0)**	**(39.7)**	**(39.5)**	**(39.3)**

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Table 5 - Net Present Value, Transformation Connection Pool, page 1

Date:	27-Apr-26
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Hawthorne x Orleans New 230kV TL
Description:	Hawthorne x Orleans New 230kV TL
Customer:	

			In-Service Date	<-------	Project year ended - annualized from In-Service Date	-------->									
		Month	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30
		Year	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
			0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast															
Load Forecast (MW)				15.6	20.4	22.5	24.1	25.4	27.0	28.8	30.3	31.7	33.0	34.4	35.8
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				15.6	20.4	22.5	24.1	25.4	27.0	28.8	30.3	31.7	33.0	34.4	35.8
Tariff Applied ($/kW/Month)				3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47
Incremental Revenue - $M				0.7	0.9	0.9	1.0	1.1	1.1	1.2	1.3	1.3	1.4	1.4	1.5
Removal Costs - $M			(0.3)												
On-going OM&A Costs - $M			0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Municipal Tax - $M				(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M			(0.3)	0.6	0.8	0.8	0.9	1.0	1.0	1.1	1.1	1.2	1.3	1.3	1.4
Income Taxes			0.1	0.1	0.3	0.2	0.2	0.1	0.1	0.0	(0.0)	(0.0)	(0.1)	(0.1)	(0.2)
Operating Cash Flow (after taxes) - $M			(0.2)	0.7	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2
		Cumulative PV @ 5.65%													
PV Operating Cash Flow (after taxes) - $M	(A)	15.0	(0.2)	0.6	1.0	0.9	0.9	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.6
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(20.6)												
- Overheads			(1.6)												
- AFUDC			(1.7)												
Total upfront capital expenditures			**(23.9)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(23.9)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**0.1**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	(B)	(23.8)	(23.8)												
Cumulative PV Cash Flow (after taxes) - $M	(A) + (B)	(8.9)	(24.0)	(23.4)	(22.4)	(21.5)	(20.6)	(19.8)	(19.0)	(18.2)	(17.4)	(16.7)	(16.0)	(15.3)	(14.7)

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**
Discount Rate - %		**5.65%**
		$M
PV Incremental Revenue		17.3
PV OM&A Costs		(0.8)
PV Municipal Tax		(1.1)
PV Income Taxes		(4.1)
PV CCA Tax Shield		3.7
PV Capital - Upfront	(23.9)	
Add: PV **Capital Contribution**	**0.0**	(23.9)
PV Capital - On-going		0.0
PV Working Capital		(0.0)
PV Surplus / (Shortfall)		(8.9)
Profitability Index*		**0.6**

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Other Assumptions

In-Service Date:	30-Sep-29
Payback Year:	2054
No. of years required for payback:	25

Table 6 - Net Present Value, Transformation Connection Pool, page 2

Date:	27-Apr-26
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Hawthorne x Orleans New 230kV TL
Description:	Hawthorne x Orleans New 230kV TL
Customer:	

<-------- Project year ended - annualized from In-Service Date -------->

		Month	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30	Sep-30
		Year	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
			13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast															
Load Forecast (MW)			37.1	38.3	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.7
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			37.1	38.3	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.7
Tariff Applied ($/kW/Month)			3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47
Incremental Revenue - $M			1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Removal Costs - $M															
On-going OM&A Costs - $M			(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Municipal Tax - $M			(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M			1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Income Taxes			(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Operating Cash Flow (after taxes) - $M			1.2	1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
PV Operating Cash Flow (after taxes) - $M	(A)		**0.6**	**0.6**	**0.6**	**0.5**	**0.5**	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC															
- Overheads															
- AFUDC															
Total upfront capital expenditures															
On-going capital expenditures			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures															
Total capital expenditures - $M															
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M															
PV Working Capital - $M															
PV Capital (after taxes) - $M	(B)														
Cumulative PV Cash Flow (after taxes) - $M	(A) + (B)		**(14.1)**	**(13.5)**	**(12.9)**	**(12.4)**	**(11.9)**	**(11.4)**	**(11.0)**	**(10.6)**	**(10.2)**	**(9.8)**	**(9.5)**	**(9.2)**	**(8.9)**

Table 7 - Revenue Requirement and Network Pool Rate Impact, page 1

Revenue Requirement and Network Pool Rate Impact **(Before Capital Contribution)**

Hawthorne x Orleans New 230kV TL		Project YE 30-Sep 2030	30-Sep 2031	30-Sep 2032	30-Sep 2033	30-Sep 2034	30-Sep 2035	30-Sep 2036	30-Sep 2037	30-Sep 2038	30-Sep 2039	30-Sep 2040	30-Sep 2041
Calculation of Incremental Revenue Requirement ($ millions)		1	2	3	4	5	6	7	8	9	10	11	12
In-service date	30-Sep-29												
Capital Cost	23.0												
Less: Capital Contribution Required	-												
Net Project Capital Cost	23.0												
Average Rate Base		11.3	22.3	21.9	21.4	21.0	20.5	20.0	19.6	19.1	18.7	18.2	17.7
Incremental OM&A Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grants in Lieu of Municipal tax		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Depreciation		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Interest and Return on Rate Base		0.7	1.4	1.4	1.4	1.3	1.3	1.3	1.2	1.2	1.2	1.2	1.1
Income Tax Provision		(0.0)	(0.2)	(0.1)	(0.1)	(0.0)	(0.0)	0.0	0.0	0.1	0.1	0.1	0.1
REVENUE REQUIREMENT PRE-TAX		**1.3**	**1.8**	**1.8**	**1.8**	**1.8**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**	**1.8**	**1.8**
Incremental Revenue		4.9	5.3	5.5	5.7	5.9	6.0	6.2	6.3	6.5	6.6	6.8	6.9
SUFFICIENCY/(DEFICIENCY)		**3.7**	**3.5**	**3.7**	**3.9**	**4.0**	**4.2**	**4.3**	**4.5**	**4.6**	**4.8**	**4.9**	**5.1**
	Base Year												
Network Pool Revenue Requirement including sufficiency/(deficiency)	1,495	1,496	1,497	1,497	1,497	1,497	1,497	1,497	1,497	1,497	1,497	1,497	1,497
Network MW	234	235	235	235	235	235	235	235	235	235	235	235	235
Network Pool Rate ($/kw/month)	6.39	6.38	6.38	6.38	6.38	6.38	6.38	6.38	6.37	6.37	6.37	6.37	6.37
Increase/(Decrease) in Network Pool Rate ($/kw/month), relative to base year		(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)
RATE IMPACT relative to base year		**-0.16%**	**-0.16%**	**-0.16%**	**-0.16%**	**-0.16%**	**-0.16%**	**-0.16%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**

Assumptions

Incremental OM&A		Years 1 to 5 0.0903341304272648% of Initial Capital each year; Years 6 to 15 0.18066826085453% of Initial Captial each year; Years 16 to 25 0.225835326068162% of Initial Capital each year.
Grants in Lieu of Municipal tax	0.33%	Transmission system average
Depreciation	2.00%	Reflects 50 year average service life for towers, conductors and station equipment, excluding land
Interest and Return on Rate Base	6.34%	Includes OEB-approved ROE of 9.36%, 4.79% on ST debt, and 4.3% on LT debt. 40/4/56 equity/ST debt/ LT debt split
Income Tax Provision	26.50%	2026 federal and provincial corporate income tax rate
Capital Cost Allowance	8.00%	100% Class 47 assets

Table 8 - Revenue Requirement and Network Pool Rate Impact, page 2

Revenue Requirement and Network Pool Rate Impact **(Before Capital Contribution)**

Hawthorne x Orleans New 230kV TL		30-Sep 2042	30-Sep 2043	30-Sep 2044	30-Sep 2045	30-Sep 2046	30-Sep 2047	30-Sep 2048	30-Sep 2049	30-Sep 2050	30-Sep 2051	30-Sep 2052	30-Sep 2053	30-Sep 2054
Calculation of Incremental Revenue Requirement ($ millions)		13	14	15	16	17	18	19	20	21	22	23	24	25
In-service date	30-Sep-29													
Capital Cost	23.0													
Less: Capital Contribution Required	-													
Net Project Capital Cost	23.0													
Average Rate Base		17.3	16.8	16.3	15.9	15.4	15.0	14.5	14.0	13.6	13.1	12.7	12.2	11.7
Incremental OM&A Costs		0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Grants in Lieu of Municipal tax		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Depreciation		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Interest and Return on Rate Base		1.1	1.1	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.7
Income Tax Provision		0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
REVENUE REQUIREMENT PRE-TAX		**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.7**	**1.7**	**1.7**	**1.7**	**1.6**	**1.6**	**1.6**	**1.6**
Incremental Revenue		7.1	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
SUFFICIENCY/(DEFICIENCY)		**5.3**	**5.4**	**5.5**	**5.5**	**5.5**	**5.5**	**5.6**	**5.6**	**5.6**	**5.6**	**5.7**	**5.7**	**5.7**
	Base Year													
Network Pool Revenue Requirement including sufficiency/(deficiency)	1,495	1,497	1,497	1,497	1,497	1,497	1,497	1,496	1,496	1,496	1,496	1,496	1,496	1,496
Network MW	234	235	235	235	235	235	235	235	235	235	235	235	235	235
Network Pool Rate ($/kw/month)	6.39	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37
Increase/(Decrease) in Network Pool Rate ($/kw/month), relative to base year		(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)
RATE IMPACT relative to base year		**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**

Table 9 - Revenue Requirement and Line Connection Pool Rate Impact, page 1

Revenue Requirement and Line Pool Rate Impact **(Before Capital Contribution)**

Hawthorne x Orleans New 230kV TL		Project YE 30-Sep 2030	30-Sep 2031	30-Sep 2032	30-Sep 2033	30-Sep 2034	30-Sep 2035	30-Sep 2036	30-Sep 2037	30-Sep 2038	30-Sep 2039	30-Sep 2040	30-Sep 2041
Calculation of Incremental Revenue Requirement ($ millions)		1	2	3	4	5	6	7	8	9	10	11	12
In-service date	30-Sep-29												
Capital Cost	52.9												
Less: Capital Contribution Required	-												
Net Project Capital Cost	52.9												
Average Rate Base		26.1	51.9	51.2	50.5	49.8	49.1	48.3	47.6	46.9	46.2	45.5	44.8
Incremental OM&A Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grants in Lieu of Municipal tax		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Depreciation		0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Interest and Return on Rate Base		1.7	3.3	3.2	3.2	3.2	3.1	3.1	3.0	3.0	2.9	2.9	2.8
Income Tax Provision		0.1	(0.0)	0.0	0.1	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.4
REVENUE REQUIREMENT PRE-TAX		**2.7**	**4.2**	**4.2**	**4.2**	**4.2**	**4.2**	**4.2**	**4.2**	**4.2**	**4.2**	**4.2**	**4.2**
Incremental Revenue		0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.1	1.1	1.1
SUFFICIENCY/(DEFICIENCY)		**(1.9)**	**(3.3)**	**(3.3)**	**(3.3)**	**(3.3)**	**(3.3)**	**(3.3)**	**(3.2)**	**(3.2)**	**(3.2)**	**(3.1)**	**(3.1)**
	Base Year												
Line Pool Revenue Requirement including sufficiency/(deficiency)	232	235	236	236	236	236	236	236	236	236	236	236	236
Line MW	226	227	227	227	227	227	227	227	227	227	227	227	227
Line Pool Rate ($/kw/month)	1.03	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
Increase/(Decrease) in Line Pool Rate ($/kw/month), relative to base year		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
RATE IMPACT relative to base year		**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**

Assumptions

Incremental OM&A		$3.68037852575368 k per new km of line each year.
Grants in Lieu of Municipal tax	0.33%	Transmission system average
Depreciation	2.00%	Reflects 50 year average service life for towers, conductors and station equipment, excluding land
Interest and Return on Rate Base	6.34%	Includes OEB-approved ROE of 9.36%, 4.79% on ST debt, and 4.3% on LT debt. 40/4/56 equity/ST debt/ LT debt split
Income Tax Provision	26.50%	2026 federal and provincial corporate income tax rate
Capital Cost Allowance	8.00%	100% Class 47 assets except for Land

Table 10 - Revenue Requirement and Line Connection Pool Rate Impact, page 2

Revenue Requirement and Line Pool Rate Impact **(Before Capital Contribution)**

Hawthorne x Orleans New 230kV TL		30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep
		2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
Calculation of Incremental Revenue Requirement ($ millions)		13	14	15	16	17	18	19	20	21	22	23	24	25
In-service date	30-Sep-29													
Capital Cost	52.9													
Less: Capital Contribution Required	-													
Net Project Capital Cost	52.9													
Average Rate Base		44.1	43.4	42.7	42.0	41.3	40.6	39.8	39.1	38.4	37.7	37.0	36.3	35.6
Incremental OM&A Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grants in Lieu of Municipal tax		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Depreciation		0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Interest and Return on Rate Base		2.8	2.8	2.7	2.7	2.6	2.6	2.5	2.5	2.4	2.4	2.3	2.3	2.3
Income Tax Provision		0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
REVENUE REQUIREMENT PRE-TAX		**4.2**	**4.2**	**4.1**	**4.1**	**4.1**	**4.0**	**4.0**	**4.0**	**3.9**	**3.9**	**3.9**	**3.8**	**3.8**
Incremental Revenue		1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
SUFFICIENCY/(DEFICIENCY)		**(3.0)**	**(3.0)**	**(3.0)**	**(2.9)**	**(2.9)**	**(2.9)**	**(2.8)**	**(2.8)**	**(2.8)**	**(2.7)**	**(2.7)**	**(2.6)**	**(2.6)**
	Base Year													
Line Pool Revenue Requirement including sufficiency/(deficiency)	232	236	236	236	236	236	236	236	236	236	236	236	236	236
Line MW	226	227	227	227	227	227	227	227	227	227	227	227	227	227
Line Pool Rate ($/kw/month)	1.03	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
Increase/(Decrease) in Line Pool Rate ($/kw/month), relative to base year		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
RATE IMPACT relative to base year		**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**

Table 11 - Revenue Requirement and Transformation Connection Pool Rate Impact, page 1

Revenue Requirement and Transformation Pool Rate Impact **(Before Capital Contribution)**

Hawthorne x Orleans New 230kV TL		Project YE 30-Sep 2030	30-Sep 2031	30-Sep 2032	30-Sep 2033	30-Sep 2034	30-Sep 2035	30-Sep 2036	30-Sep 2037	30-Sep 2038	30-Sep 2039	30-Sep 2040	30-Sep 2041
Calculation of Incremental Revenue Requirement ($ millions)		1	2	3	4	5	6	7	8	9	10	11	12
In-service date	30-Sep-29												
Capital Cost	23.9												
Less: Capital Contribution Required	-												
Net Project Capital Cost	23.9												
Average Rate Base		11.7	23.2	22.7	22.3	21.8	21.3	20.8	20.3	19.9	19.4	18.9	18.4
Incremental OM&A Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grants in Lieu of Municipal tax		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Depreciation		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Interest and Return on Rate Base		0.7	1.5	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.2	1.2	1.2
Income Tax Provision		(0.0)	(0.2)	(0.1)	(0.1)	(0.0)	(0.0)	0.0	0.0	0.1	0.1	0.1	0.1
REVENUE REQUIREMENT PRE-TAX		**1.3**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**
Incremental Revenue		0.7	0.9	0.9	1.0	1.1	1.1	1.2	1.3	1.3	1.4	1.4	1.5
SUFFICIENCY/(DEFICIENCY)		**(0.7)**	**(1.0)**	**(1.0)**	**(0.9)**	**(0.9)**	**(0.8)**	**(0.7)**	**(0.7)**	**(0.6)**	**(0.5)**	**(0.5)**	**(0.4)**
	Base Year												
Transformation Pool Revenue Requirement including sufficiency/(deficiency)	663	664	665	665	665	665	665	665	665	665	665	665	665
Transformation MW	191	191	191	191	191	191	191	191	191	191	191	191	191
Transformation Pool Rate ($/kw/month)	3.47	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48
Increase/(Decrease) in Transformation Pool Rate ($/kw/month), relative to base year		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
RATE IMPACT relative to base year		**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**

Assumptions		
Incremental OM&A		Years 1 to 5 $267.64610253377 k each year; Years 6 to 15 $535.29220506754 k each year; Years 16 to 25 $669.115256334425 k each year.
Grants in Lieu of Municipal tax	0.33%	Transmission system average
Depreciation	2.00%	Reflects 50 year average service life for towers, conductors and station equipment, excluding land
Interest and Return on Rate Base	6.34%	Includes OEB-approved ROE of 9.36%, 4.79% on ST debt, and 4.3% on LT debt. 40/4/56 equity/ST debt/ LT debt split
Income Tax Provision	26.50%	2026 federal and provincial corporate income tax rate
Capital Cost Allowance	8.00%	100% Class 47 assets

Table 12 - Revenue Requirement and Transformation Connection Pool Rate Impact, page 2

Revenue Requirement and Transformation Pool Rate Impact **(Before Capital Contribution)**

Hawthorne x Orleans New 230kV TL		30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep	30-Sep
		2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
Calculation of Incremental Revenue Requirement ($ millions)		13	14	15	16	17	18	19	20	21	22	23	24	25
In-service date	30-Sep-29													
Capital Cost	23.9													
Less: Capital Contribution Required	-													
Net Project Capital Cost	23.9													
Average Rate Base		18.0	17.5	17.0	16.5	16.0	15.6	15.1	14.6	14.1	13.6	13.2	12.7	12.2
Incremental OM&A Costs		0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Grants in Lieu of Municipal tax		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Depreciation		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Interest and Return on Rate Base		1.1	1.1	1.1	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.8	0.8	0.8
Income Tax Provision		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
REVENUE REQUIREMENT PRE-TAX		**1.9**	**1.9**	**1.9**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.7**	**1.7**	**1.7**	**1.7**	**1.6**
Incremental Revenue		1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
SUFFICIENCY/(DEFICIENCY)		**(0.3)**	**(0.3)**	**(0.2)**	**(0.2)**	**(0.2)**	**(0.2)**	**(0.2)**	**(0.1)**	**(0.1)**	**(0.1)**	**(0.1)**	**(0.0)**	**(0.0)**
	Base Year													
Transformation Pool Revenue Requirement including sufficiency/(deficiency)	663	665	665	664	664	664	664	664	664	664	664	664	664	664
Transformation MW	191	191	191	191	191	191	191	191	191	191	191	191	191	191
Transformation Pool Rate ($/kw/month)	3.47	3.48	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47
Increase/(Decrease) in Transformation Pool Rate ($/kw/month), relative to base year		0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RATE IMPACT relative to base year		**0.29%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**

Table 13 - DCF Assumptions

Hydro One Networks -- Transmission Connection Economic Evaluation Model
2026 Parameters and Assumptions

Transmission rates are based on current OEB-approved uniform provincial transmission rates.

Monthly Rate ($ per kW)	
Network	**6.39**
Transformation	**3.47**
Line	**1.03**

Grants in lieu of Municipal tax (% of up-front capital expenditure, a proxy for property value): **0.33%**

Income taxes:

Basic Federal Tax Rate - % of taxable income:	2026	**15.00%**
Ontario corporation income tax - % of taxable income:	2026	**11.50%**

Capital Cost Allowance Rate:

Class 47 costs	2026	**8%**
Easement rights	2026	**5%**
Decision Support defined costs (2)	2026	**0%**
Decision Support defined costs (3)	2026	**0%**

After-tax Discount rate: **5.65%**

REVENUE REQUIREMENT INFORMATION AND DEFERRAL ACCOUNT REQUESTS

1.0 REVENUE REQUIREMENT AND TRANSMISSION SYSTEM PLAN INFORMATION

The Project was not individually identified in an Investment Summary Document within Hydro One's Transmission System Plan[1] that supported its most recent 2023-2027 transmission rate application (EB-2021-0110). Instead, the Project's planned capital expenditures for the rate period were included within the "Other System Service Investments" capital envelope presented in Table 7 of Exhibit B, Tab 2, Schedule 1, Section 2.8. The Project's need date was beyond the current rate period, thus no in-service rate base additions for the Project were included in the OEB-approved 2023 to 2027 revenue requirement. Detailed information regarding the Project's capital expenditures and in-service rate base additions will be provided in Hydro One's upcoming transmission rate application for the 2028 to 2032 period.

2.0 DEFERRAL ACCOUNT REQUEST INFORMATION

There are no new deferral or variance account requests being made as part of this Application.

[1] This is consistent with proceeding EB-2021-0110 in Exhibit B, Tab 1, Schedule 1, Section 2.11, that states only projects which exceed a materiality threshold of $3M in a single year will be disclosed in an ISD.

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PROJECT SCHEDULE

TASK	START	FINISH
Section 92 Approval	May-2026	Jan-2027
LINES		
Receipt of Other Key Permits and Approvals	Nov-2024	Jun-2027
Voluntary Property Rights Acquisition[1]	Jun-2025	Jan-2027
Detailed Engineering	Dec-2024	May-2026
Procurement	Jun-2026	Dec-2026
Construction	Feb-2027	Sep-2029
Commissioning	Aug-2027	Sep-2029
In Service		Sep-2029
Site Remediation Completion	Aug-2027	Oct-2029
STATIONS[2]		
Receipt of Other Key Permits and Approvals	Nov-2024	Jun-2027
Detailed Engineering	Dec-2024	May-2026
Procurement	Jul-2024	Jul-2027
Construction	Feb-2027	Sep-2029
Commissioning	Jun-2027	Sep-2029
In Service		Sep-2029
Site Remediation Completion	May-2028	Oct-2029

[1] Completion timing is dependent upon property owner-specific negotiations. The above schedule does not include expropriation relief under Section 99 of the OEB Act, if required.
[2] The proposed stations schedule reflects the key milestones for the station modifications at Hawthorne TS and Orleans TS.

The table above outlines the forecast schedule for the Project and has been predicated on Hydro One successfully securing leave to construct approval by January 2027. Construction is set to commence in February 2027 and the cost evidence provided in **Exhibit B, Tab 7, Schedule 1** is underpinned by this schedule**.** If Hydro One is unsuccessful in securing voluntary agreements, within a short period following leave to construct approval, Hydro One intends to seek expropriation authority from the OEB in accordance with section 99 of the *OEB Act, 1998*. As identified in **Exhibit B, Tab 7, Schedule 1**, delays in regulatory approvals beyond those contemplated in the project schedule documented above could materially impact the cost of the Project. Contingency has been carried on the Project to account for minor deviations to this schedule, however, material delays in securing approvals would have significant impacts that have not been carried in contingency. Project timelines have been based on recent OEB processing timelines and take into consideration the OEB’s Performance Standards for Processing Leave to Construct Applications.

DESCRIPTIONS OF THE PHYSICAL DESIGN

1.0 ROUTE DESCRIPTION

There is an existing transmission corridor between Hawthorne TS and Orleans TS, which is the primary supply route for the Orleans area and surrounding communities in the southeastern part of Ottawa. Currently along this transmission corridor there are two parallel 230 kV double-circuit transmission tower lines. On the north side are circuits D5A and H9A[1] used to supply the Orleans area, and on the south side are circuits A41T and A42T used for the interconnection with Hydro-Québec TransÉnergie.

The proposed new 115 kV single-circuit transmission line will run parallel between these existing two double-circuit transmission tower lines from structure 324 (northeast of Hawthorne TS) to structure 292 (outside of Orleans TS). There will also be a new 230 kV transmission line connection required to be built from Hawthorne TS to structure 324 to enable the reconfiguration of the existing 115 kV circuit H9A to 230 kV, and similarly a reconfiguration of the circuits at structure 292 in order to utilize the existing line tap into Orleans TS. The total line length of the Project is approximately 11 km and will primarily utilize the existing transmission corridor.

Once the proposed Project is built the existing H9A transmission line between Hawthorne TS and Orleans TS will be renamed to A25 and will be operated at 230 kV. The proposed new 115 kV single-circuit transmission line will become H9A thereby ensuring a continued reliable 115 kV supply to the area.

1.1 ROUTE DETAILS

i. The Project route starts at Hawthorne TS located west of Highway 417 and south of Walkley Road (Regional Road 74) in the Orleans area.

[1] Circuit H9A is rated for 230 kV but is currently configured to operate at 115 kV.

ii. The new 230 kV transmission line connection will exit the north side of Hawthorne TS and head northeast along a new corridor for approximately 1 km towards structure 324 that resides within the existing transmission corridor.

iii. At structure 324, the new 230 kV transmission line connection will converge with the existing H9A infrastructure and the circuits will swap towers.

iv. From structure 324 to structure 292, the proposed new 115 kV single-circuit transmission line infrastructure will run northeast parallel between the existing two double-circuit transmission tower lines for approximately 10 km. The existing H9A infrastructure between Hawthorne TS and Orleans TS will be renamed to circuit A25 and operated at 230 kV, and the new 115 kV transmission line infrastructure will be named circuit H9A

v. At structure 292 just outside of Orleans TS, the new 115 kV transmission line (H9A) will converge once again with circuit A25. Circuit A25 will utilize the existing line tap to terminate at Orleans TS, and circuit H9A will jumper to the east side of structure 292 and reconnect to the existing 115kV transmission line infrastructure to continue to supply the 115 kV system in the area.

A map showing the general route of the Project is provided as **Attachment 1** of **Exhibit B, Tab 2, Schedule 1**.

2.0 LINE DESCRIPTION

The new 115 kV transmission line will have one (1) circuit comprised of 1443.7 kcmil ACSR/TW "Superior" conductor per phase, and one (1) overhead aluminum clad steel shieldwire, primarily supported on H-frame structures. Further, the 115 kV transmission line will have the following attributes:

- The line will have a continuous ampacity of 1121 A and LTE ampacity of 1507 A (summer 35C);
- Porcelain insulators will be used along the line in accordance with Hydro One standards;

- Stockbridge-type vibration dampers to dampen the conductor and shieldwire in accordance with Hydro One standard, based on the final line configuration and per the manufacturer's design;
- The H-frame structures will be direct buried; and the lattice tower structures will utilize a pier foundation; and
- The line will make use of fifty-two (52) wood H-frame structures (refer to Figures 1,2 and 3) and six (6) composite H-frame structures (refer to Figure 4) with nominal spans of 158 m. There will also be five (5) wood 3-pole dead end structures (refer to Figure 5), and six (6) BPEX-M tower structures (refer to Figure 6) used to cross under the existing lines at the tapping locations (i.e., structure 324 and 292).

For the new 230 kV transmission line connection required to be built from Hawthorne TS to structure 324, the line will have the following attributes:

- The line will have one (1) 1443.7 kcmil ACSR/TW "Superior" conductor per phase, and two (2) 7#5 aluminum clad steel overhead shieldwires;
- The line will have a continuous ampacity of 1121 A and LTE ampacity of 1507 A (summer 35C);
- The line will be primarily supported on six (6) self-supported lattice structures either type BPEX-M, X5M, or Low Gatineau (refer to Figure 6 to 8 respectively), and two (2) custom steel poles;
- Crossing and slack spans will be under 100m and full tension spans will range from 200 m to 340 m;
- Lattice structures will use traditional augured concrete pier foundations;
- Porcelain insulators and Stockbridge-type vibration dampers will be used along the line exit; and
- Jumpers will be added on the spans to the east and west of structure 324.

The existing line tap into Orleans TS with a continuous ampacity of 800 A will be utilized; however, jumpers will need to be added and reconfigured at structure 292. A floating dead-end assembly will also need to be installed at structure 292 to isolate circuit A25 and circuit

H9A. Mid span openers will be used at the first and last spans of the line to allow for further circuit isolation.

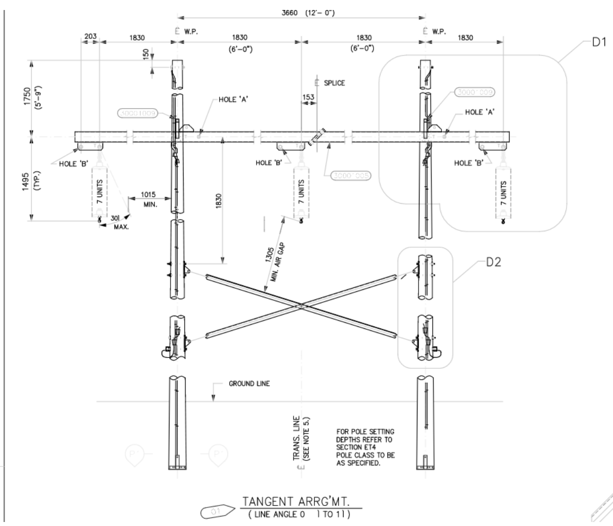

Figure 1: Wood H-frame Suspension

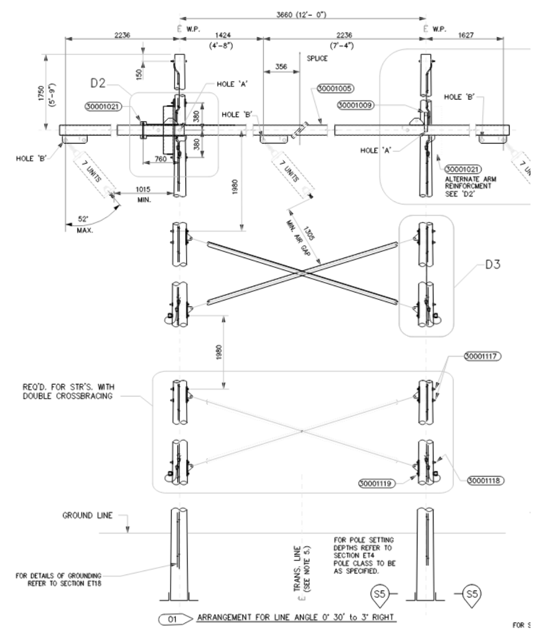

Figure 2: Wood H-frame Light Angle Suspension

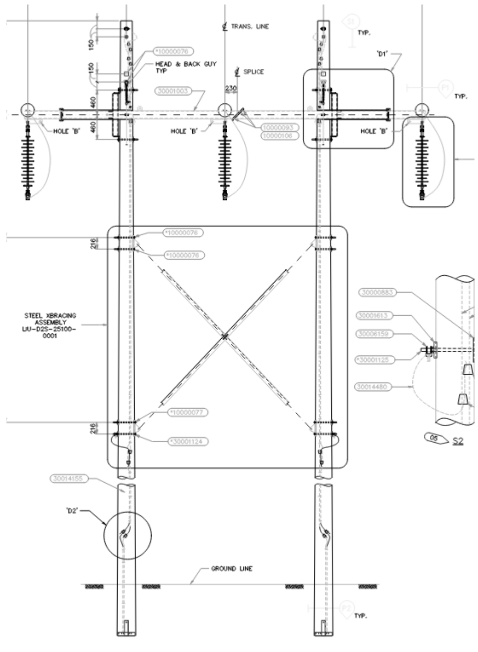

Figure 3: Wood H-frame In Line Dead-End

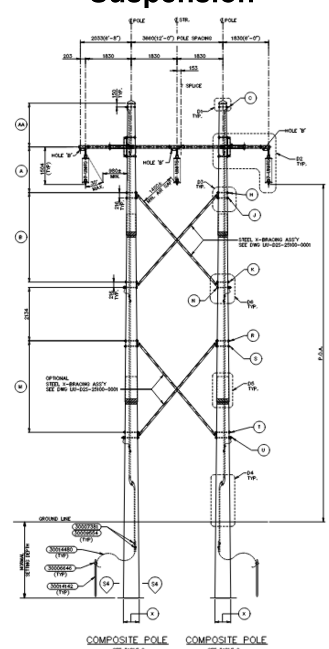

Figure 4: Composite H-frame Suspension

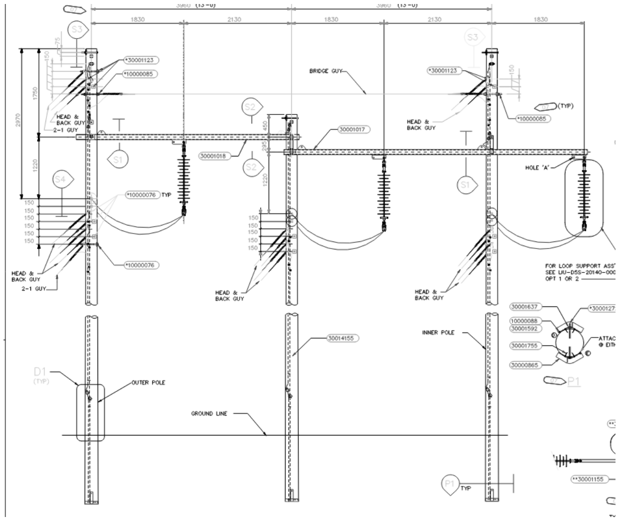

Figure 5: Wood 3-Pole Dead-End

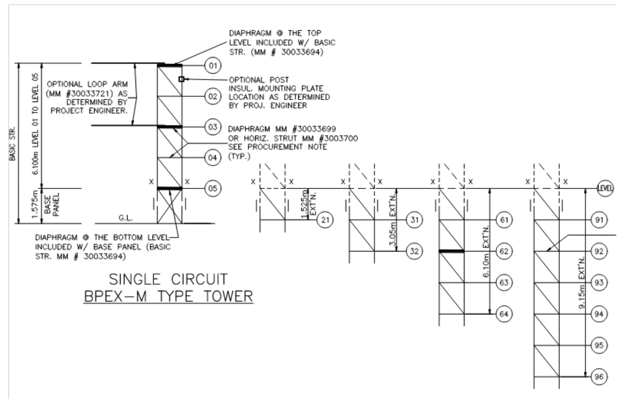

Figure 6: BPEX-M Lattice Tower

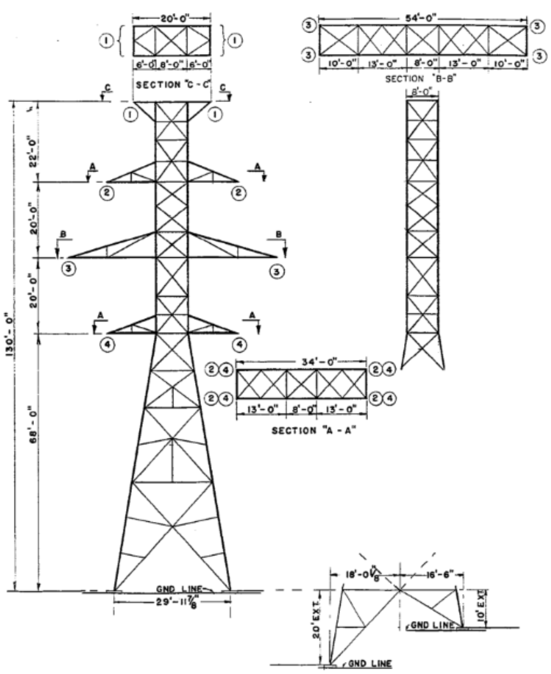

Figure 7: X5M Lattice Tower

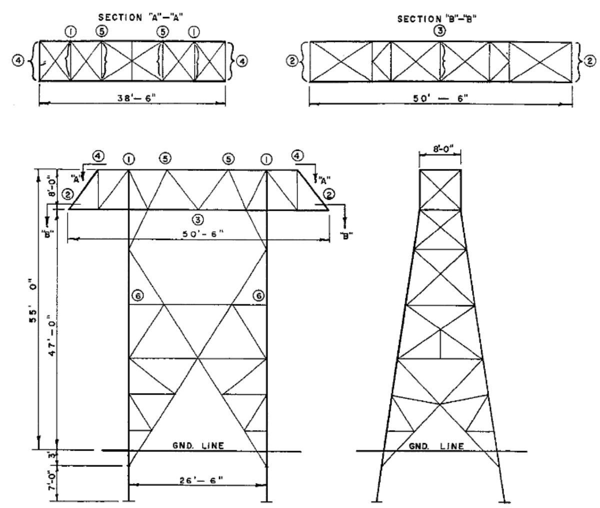

Figure 8: Low Gatineau Lattice Tower

3.0 LINE REMOVAL

No line removals will be required beyond the removal of the temporary MTU by-pass within the station at Orleans TS as noted in Section 4.0 below.

4.0 STATION WORK

The transmission station work will consist of terminal station modifications at Hawthorne TS and Orleans TS to accommodate the new transmission line facilities. The following outlines the specific work required at each of the stations:

Hawthorne TS

The scope of work to expand the existing station to facilitate the connection of the new transmission line includes:

- Install one (1) line entrance structure for terminating the new transmission line;
- Install approximately 70 m of Gas Insulated Line, including six (6) bushings, six (6) 230 kV surge arresters, and eighteen (18) 900 kV BIL station post insulators;
- On the existing diameter, install one (1) 230 kV 3000A circuit breaker, two (2) 230 kV 3000A circuit breaker isolating disconnect switches, one (1) 230 kV 2000 A combined line disconnect and grounding switch, and three (3) 230 kV line CVTs and associated CVT fuses boxes; and
- Install grounding for new equipment and structure; new cable trenches and switchyard lighting; an automatic transfer switch and AC and DC auxiliary power for new equipment and associated buildings, PCT equipment and associated cable trays, cable entrance and supports in the existing building.

Orleans TS

The scope of work to expand the existing station to facilitate the connection of the new transmission line includes:

- Replace the existing 50/83 MVA, 115/27.6 kV transformer (T1) and associated three (3) 115 kV CVTs and three (3) 115 kV surge arrestors with a new 75/100/125 MVA, 230/27.6/27.6 kV transformer, three (3) new 230 kV CVTs, three (3) new 230 kV surge arresters, and installation of a firewall between the new transformer (T1) and existing transformer (T2);
- On the LV side: install six (6) 27.6 kV surge arresters, new rigid bus, two (2) 1.5 ohm neutral reactors and associated neutral connections, one (1) 27.6 kV 3000 A transformer circuit breaker and two (2) 27.6 kV 3000 A transformer breaker

disconnect switches, two (2) 27.6 kV 1200 A feeder circuit breakers and four (4) 27.6 kV 1200 A feeder breaker disconnect switches, one (1) 27.6 kV 1200 A feeder tie switch, and three (3) CT/PT devices on the new secondary bus;

- Install new grounding grid along with equipment and structure grounding as required, as well as modifications to the existing transformer protections and controls settings to accommodate new equipment; and
- Install a temporary MTU by-pass while the station bay at Orleans TS is upgraded. Once the station bay is upgraded and the A25 circuit is terminated at Orleans TS, the temporary MTU bypass will be removed.

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OPERATIONAL DETAILS

The proposed facilities will be part of the Greater Ottawa transmission system and are required to strengthen the transmission system and increase the supply capacity by expanding the 230 kV system while preserving the existing 115 kV system. Hydro One protection, control and telecom facilities installed as part of the Project will protect the proposed transmission infrastructure by detecting faults and isolating faulted elements. Upon completion of this Project, Orleans TS will be supplied by the two 230 kV circuits A25 and D5A, thereby eliminating the connection to the 115 kV circuit H9A, and improving overall operability and reliability of the transmission system. The terminal stations for the 230 kV circuits will be Hawthorne TS and Orleans TS, as aforementioned in the Application. All other existing supply stations connected to the 115 kV circuit H9A will continue to be supplied from the 115 kV system. The proposed facilities will be operated in accordance with the procedures of Hydro One's ISOC as directed by the IESO.

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LAND MATTERS

1.0 THE ROUTE

As referenced in the Application, the proposed Project involves constructing new transmission line facilities along an approximately 11 km route between Hawthorne TS and Orleans TS; including a 10 km 115 kV single-circuit transmission line and a 1 km 230 kV transmission line connection into Hawthorne TS. The 115 kV transmission line will require a right-of-way width of 30 m, and the 230 kV line tap will require a right-of-way width of 46 m.

The majority of the route (approximately 10 km) will be sited within an existing transmission corridor between two existing double-circuit transmission lines. The transmission corridor will be situated on primarily federal and municipal lands, with the remaining balance mainly on private lands, as further outlined in Table 1 below. The proposed transmission corridor passes primarily through environmental and agricultural lands, with a limited section of residential/industrial/commercial lands near Orleans TS. Utilizing existing infrastructure and facilities is consistent with the *Ministry of Municipal Affairs and Housing Provincial Policy Statement, 2024*[1] under the *Planning Act,* which more specifically states that the co-location of linear infrastructure should be promoted, where appropriate.

2.0 DESCRIPTION OF LAND RIGHTS

The Project will require Hydro One to acquire land rights from 44 directly impacted properties, consisting of 11 privately held properties, 10 federally held properties, 1 provincially held property, 21 municipally held properties and 1 railway crossing. The majority of properties will require Hydro One to acquire easement interests or a fee simple interest at the mutual agreement of the property owner and Hydro One. Hydro One is working with directly impacted property owners to negotiate amicable voluntary agreements.

[1] Ministry of Municipal Affairs and Housing Provincial Policy Statement, 2024, under the Planning Act, Sections 3.3.5, page 17.

The relative area proportions specific to the properties affected requiring permanent land rights are as follows:

Table 1 - Summary of Property Types and Sized Required

Land Ownership Type	Area (Hectares)	Proportion of Route (%)
Private Lands	4.48	13.49%
Federal Lands	19.32	58.16%
Municipal Lands	8.74	26.31%
Provincial Lands	0.59	1.78%
Railway Lands	0.09	0.27%

3.0 MAPS OF THE PROJECT AREA

At **Exhibit B, Tab 2, Schedule 1, Attachment 1**, Hydro One has provided a map with the intention it be used as the Application's *Notice Map*. **Attachment 1 of this Schedule** provides a more detailed route map that illustrates, as appropriate, properties along line route sections with PIN numbers[2] of the land over, under, on or adjacent to which the line runs.

4.0 DESCRIPTION OF NEW LAND RIGHTS REQUIRED

The Project corridor will include a combination of the following land rights requirements:

- Hydro One statutory easements on Provincially owned (Bill 58) lands (no new land rights required)
- Easement or fee simple rights on federally, provincially, municipally owned and private properties (new land rights required);
- Rail and/or highway crossing agreement (new land rights required); and
- Temporary access and/or construction rights on federally, provincially, municipally owned and/or private properties for access roads, temporary work headquarters, laydown areas, and material storage facilities (new land rights required).

[2] PIN numbers have been provided and can be reasonably utilized to validate lot and concession numbers as may be necessary for the purposes of this proceeding.

Hydro One will document all required new land rights to construct, operate and maintain the transmission line in several agreements. On affected properties, the following land rights agreements are or may be required:

- Early Access Agreement;
- Option to Purchase a Limited Interest – Easement;
- Compensation and Incentive Agreement – Easement;
- Option to Purchase a Limited Interest – Fee Simple
- Compensation and Incentive Agreement – Fee Simple;
- Rail and/or Highway Crossing Agreement (provided by VIA Rail/CN and Rail/MTO at a later date);
- Encroachment Permit (provided by MTO at a later date);
- License of Occupation (provided by NCC at a later date);
- Agreement for Temporary Rights;
- Off Corridor Access; and
- Damage Claim Agreement/Waiver.

Where crossings of public roads and highways are contemplated and indicated in **Attachment 1 of this Schedule**, Hydro One will rely on the land rights afforded by section 41 of the *Electricity Act* (where applicable). Hydro One will notify and work with impacted road authorities, including municipalities and ministries, and obtain all required permits and/or agreements, including where agreements are required for the placement of infrastructure as per section 41(9) of the *Electricity Act*. All road crossings will be designed to meet CSA vertical clearance standards. Hydro One expects that permits/agreements for all required crossings will be acquired either prior to the start of construction or on an as needed basis.

Temporary rights may be required across private lands to facilitate construction of the Project. These rights will be negotiated and acquired as and when needed.

5.0 EARLY ACCESS TO LAND

Hydro One requires early access to the corridor to perform various activities/studies associated with the Project which include specific environmental studies, engineering and design studies, and property specific land valuations/studies. In order to facilitate the required access to the properties affected by the corridor in advance of Leave to Construct approval, Hydro One has been entering into early access agreements with affected landowners. As of the date of this filing, Hydro One has achieved voluntary early access agreements for 100% of the private properties that require new land rights. Hydro One has also received permits from the City of Ottawa and the NCC to carry out necessary activities/studies on their properties.

6.0 LAND ACQUISITION PROCESS

Hydro One is seeking voluntary property rights agreements with affected private property owners based on its project-specific LACP. The LACP principles are founded upon Hydro One's past experience pertaining to land acquisition matters for new transmission projects, and act as a roadmap for affected property owners to understand Hydro One's acquisition process. Hydro One's central consideration is the need for affected property owners to have flexibility and choice while balancing Hydro One's desire to achieve timely acquisition of land interests and its obligation to ensure that expenditures are fair and reasonable to Ontario transmission ratepayers.

Hydro One has been meeting with affected private property owners since July 2025. The objective of these meetings has been to introduce Hydro One's voluntary land acquisition process. Independent site-specific property appraisals are on-going, and Hydro One is preparing voluntary property settlement offers based on the site-specific appraisals and Hydro One's LACP. As of May 15, 2026, no voluntary property settlement offers have been made. Hydro One will begin providing voluntary property settlement offers to affected property owners in Spring 2026. These offers will be extended to affected property owners on an as-ready basis. All property owners and/or their legal counsel will be given sufficient time to review Hydro One's voluntary property settlement offer. To that end, it should be noted that during property acquisition discussions, affected property owners will be advised that they have the option to receive independent legal advice and that Hydro One is committed to reimbursing affected property owners for reasonably incurred legal fees associated with the review and execution of the necessary land rights agreements. Hydro One will continue working with each property owner with the objective of reaching voluntary property rights settlements.

Hydro One has also been meeting with representatives from the NCC and the City of Ottawa since September 2024. Hydro One has established joint Terms of References with both entities for carrying out independent site-specific property appraisals on these lands. The property rights on NCC lands can only be obtained following Federal Land Use, Design and Transaction Approval; this approval is expected in July 2026. Hydro One will continue working with the NCC and the City of Ottawa with the objective of reaching voluntary property rights settlements.

All voluntary property rights agreements will be in the form of an option agreement. Hydro One will exercise these options and conclude the land rights agreements once it has received the OEB's Leave to Construct approval of the Project. Once the option agreements are exercised, Hydro One will register easements on title for properties, or Hydro One will acquire the fee simple interest in the properties as required.

All other applicable agreements (e.g. rail crossing agreements, temporary rights agreements, etc.) will be utilized as part of the land acquisition process as required. A summary of all land negotiations to date, including their status, is summarized in Table 2 below. Further details on the properties and permits associated with the Project route are provided in **Attachment 2 of this Schedule**.

Table 2 - Land Acquisition Status (As of May 15, 2026)

Property Type	Number of Properties	Early Access Agreement Offered	Early Access Achieved	Voluntary Settlement Agreements Offered	Voluntary Settlement Agreements Achieved	Issues	Resolution Approach
Private Lands	11	100%	100%	0			
Federal Lands[3]	10	N/A	100%[4]	0			
Municipal Lands	21	N/A	100%[5]	0			
Provincial Lands	1	N/A	N/A	0			
Railway Lands	1	N/A	N/A	0			

7.0 LAND-RELATED FORMS

Provided as **Attachments 3 through 10 of this Schedule**, are the land rights agreements that Hydro One intends to utilize to obtain the required new land rights for the Project and for related Project activities. Table 3 below indicates the proceeding where the forms of these agreements were previously approved.

Table 3 - Forms of Agreement Remaining Materially Unchanged

Form of Agreement	Attachment No.	Previous OEB Docket
Early Access Agreement	3	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 3
Option to Purchase a Limited Interest – Easement	4	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 4
Compensation and Incentive Agreement – Easement	5	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 5
Option to Purchase a Limited Interest – Fee Simple	6	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 6
Compensation and Incentive Agreement – Fee Simple	7	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 7
Agreement for Temporary Rights	8	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 9
Off Corridor Access	9	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 10
Damage Claim Agreement/Waiver	10	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 12

[3] Federal Lands include nine (9) NCC properties and one (1) VIA rail property.
[4] Permits were only required and obtained from NCC to carry out the necessary early access activities/studies.
[5] A consent to enter permit was obtained from the City of Ottawa to carry out the necessary early access activities/studies.

All of these agreements are "materially unchanged" when compared to the forms of agreements previously approved; however, for completeness, a summary of the non-substantive changes are noted below:

- **Early Access Agreement:** This agreement is the same as approved in proceeding EB-2024-0155 with the exception of the Grantor option on term of agreement under Clause 2 (ii) of the form of agreement;
- **Option to Purchase a Limited Interest – Easement and Fee SImple:** These agreements are the same as approved in proceeding EB-2024-0155 with the exception of the injurious affection damage language under Recital C of the forms of agreements;
- **Compensation and Incentive Agreement – Easement:** This agreement is the same as approved in proceeding EB-2024-0155 with the exception of the Woodlot Compensation clause under Clause 2 (d); and the trigger and timing for market value top-up in Clause 1 (b) of the form of agreement; and
- **Compensation and Incentive Agreement – Fee Simple:** This agreement is the same as approved in proceeding EB-2024-0155 with the exception of: the removal of the premium above Fair Market Value wording in Clause 1 (b) as it is addressed in Clause 2 (c); the confirmation of actual lands by survey under Clause 1 (c); the Woodlot Compensation clause under Clause 2 (d); and the trigger and timing for market value top-up in Clause 1 (b) of the form of agreement.

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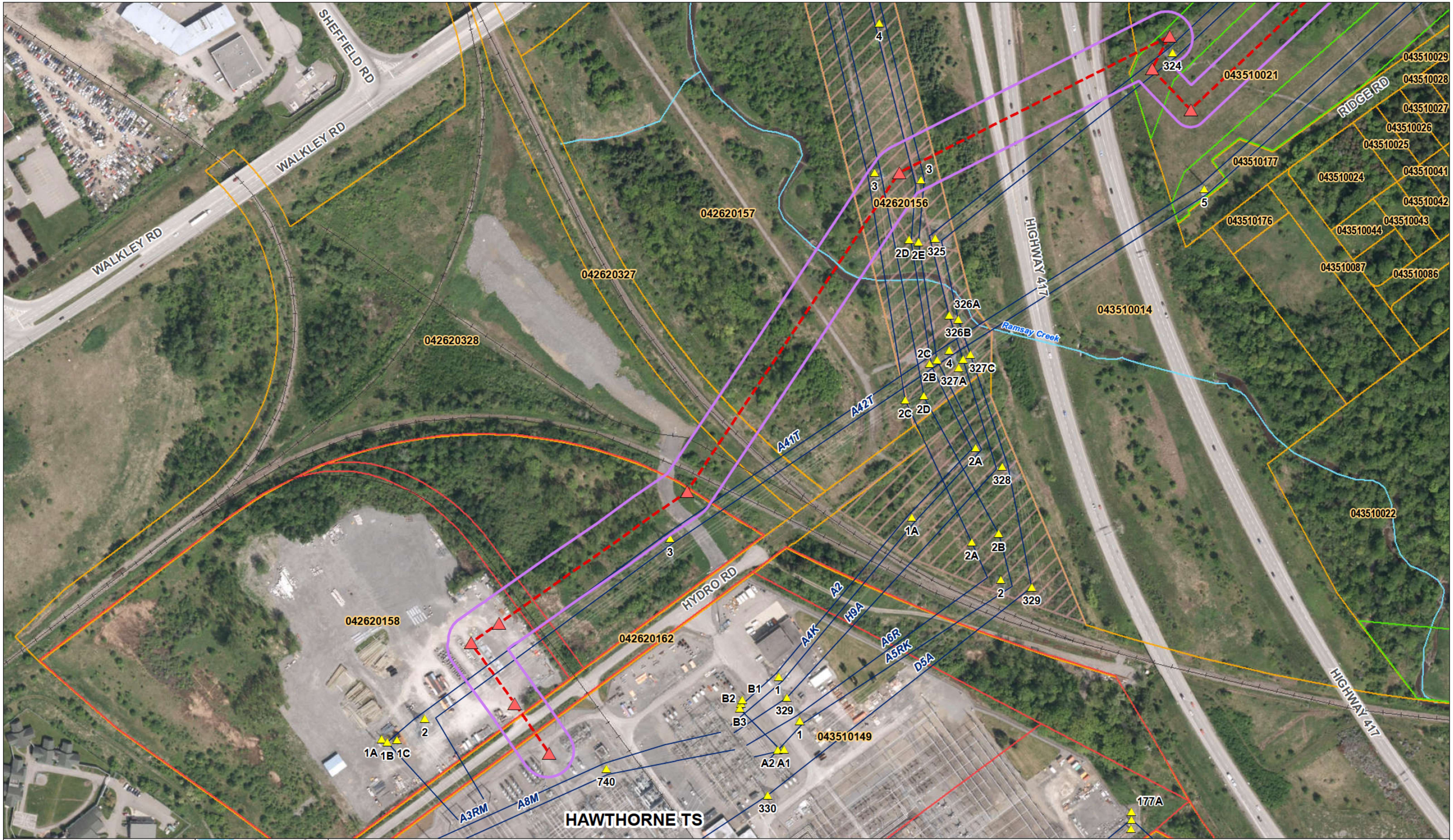
DETAILED ROUTE MAP



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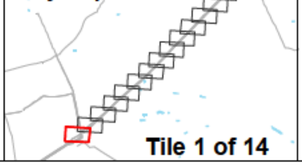
Key Map



Tile 1 of 14

- Existing Structures
- Structures for Proposed Project
- Centerline for Proposed Project
- ROW for Proposed Project
- Station
- Junction
- Existing Transmission Line
- Railway
- Hydro One Owned Lands
- Hydro One Existing Easement
- Bill 58
- Property Boundary
- Watercourse
- Wetlands
- Waterbody
- Municipal Boundary

Orleans Area Reinforcement Project
General Area Map

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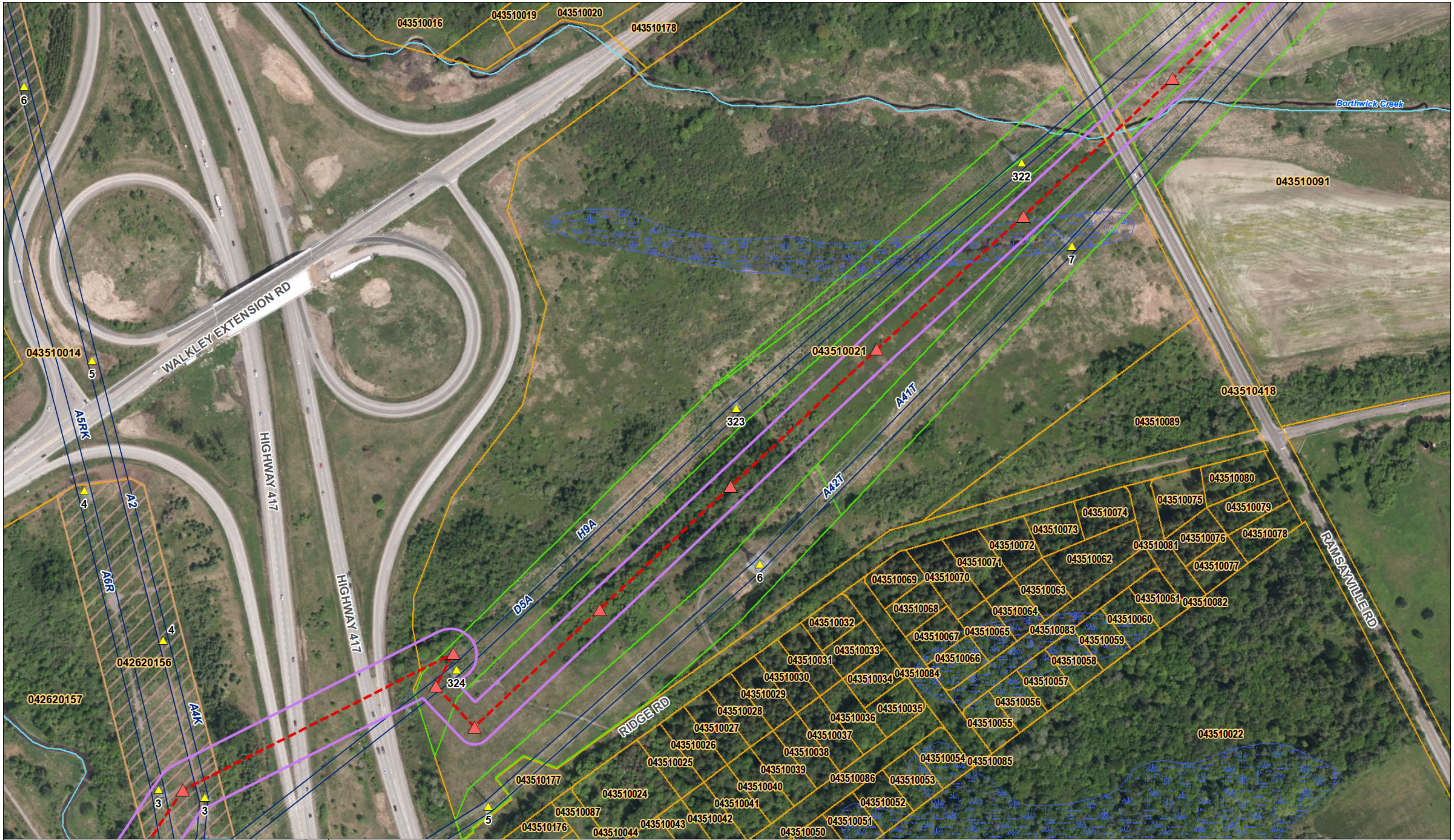

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Key Map

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Legend			
Existing Structures	Station	Hydro One Owned Lands	Watercourse
Structures for Proposed Project	Junction	Hydro One Existing Easement	Wetlands
Centerline for Proposed Project	Existing Transmission Line	Bill 58	Waterbody
ROW for Proposed Project	Railway	Property Boundary	Municipal Boundary

Orleans Area Reinforcement Project
General Area Map

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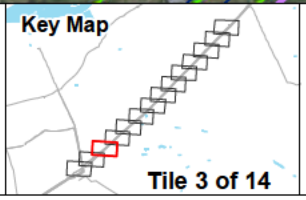

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Orleans Area Reinforcement Project
General Area Map

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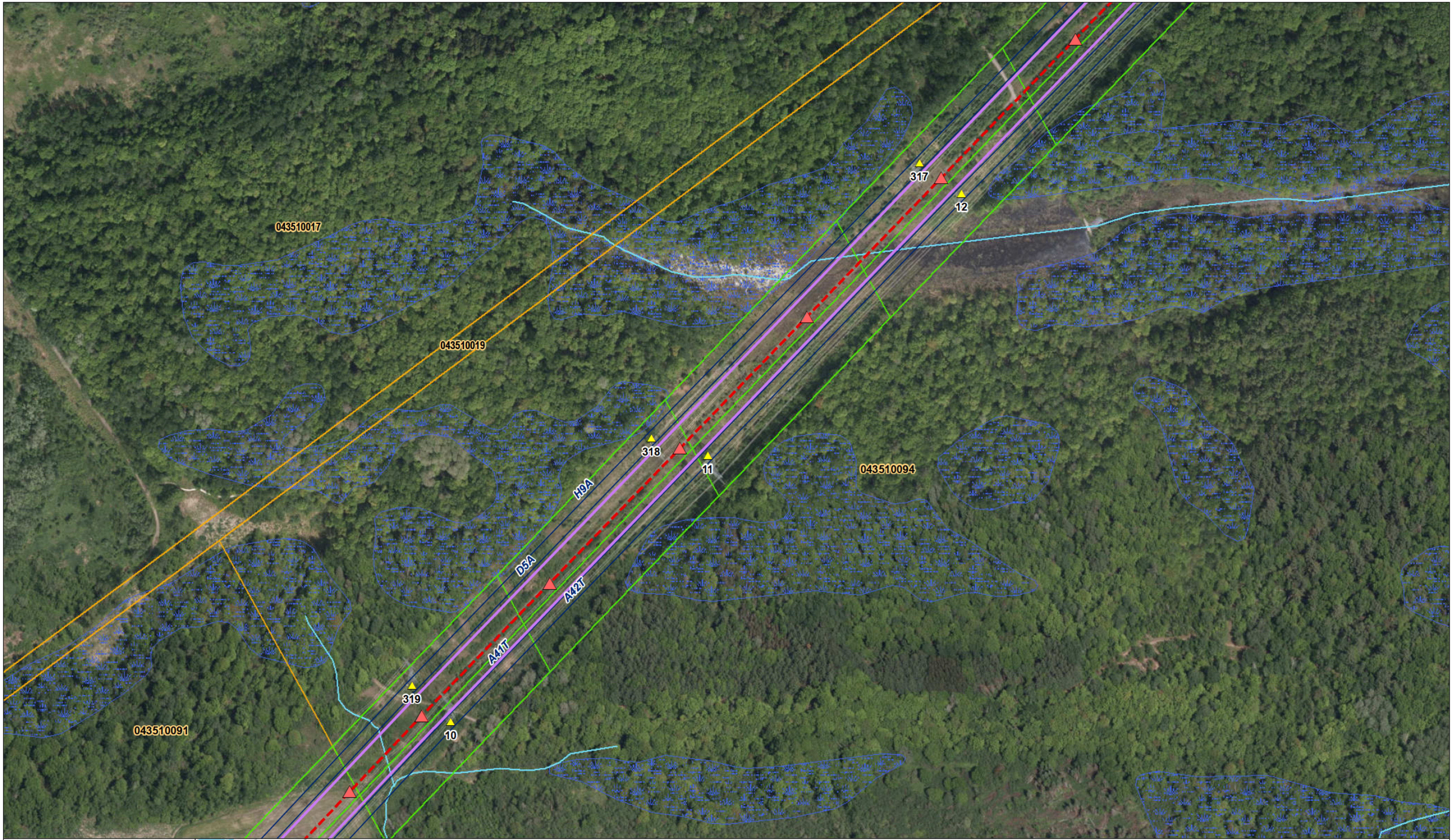

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Key Map

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Existing Structures
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Centerline for Proposed Project
ROW for Proposed Project
Station
Junction
Existing Transmission Line
Railway
Hydro One Owned Lands
Hydro One Existing Easement
Bill 58
Property Boundary
Watercourse
Wetlands
Waterbody
Municipal Boundary

Orleans Area Reinforcement Project
General Area Map

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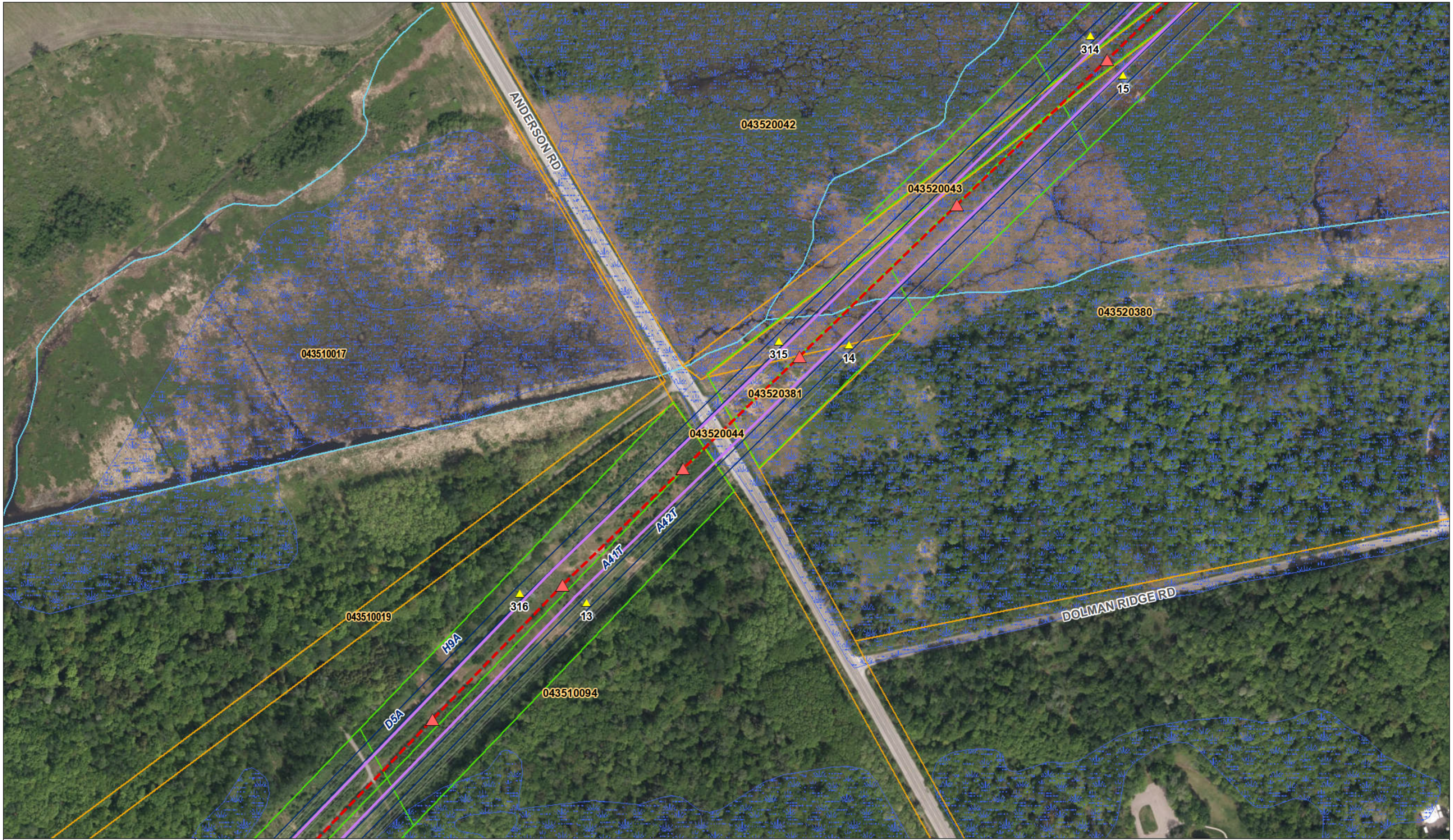

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Key Map
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- Existing Structures
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- Centerline for Proposed Project
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- Station
- Junction
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Orleans Area Reinforcement Project
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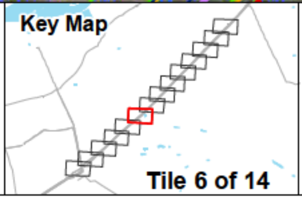

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Orleans Area Reinforcement Project
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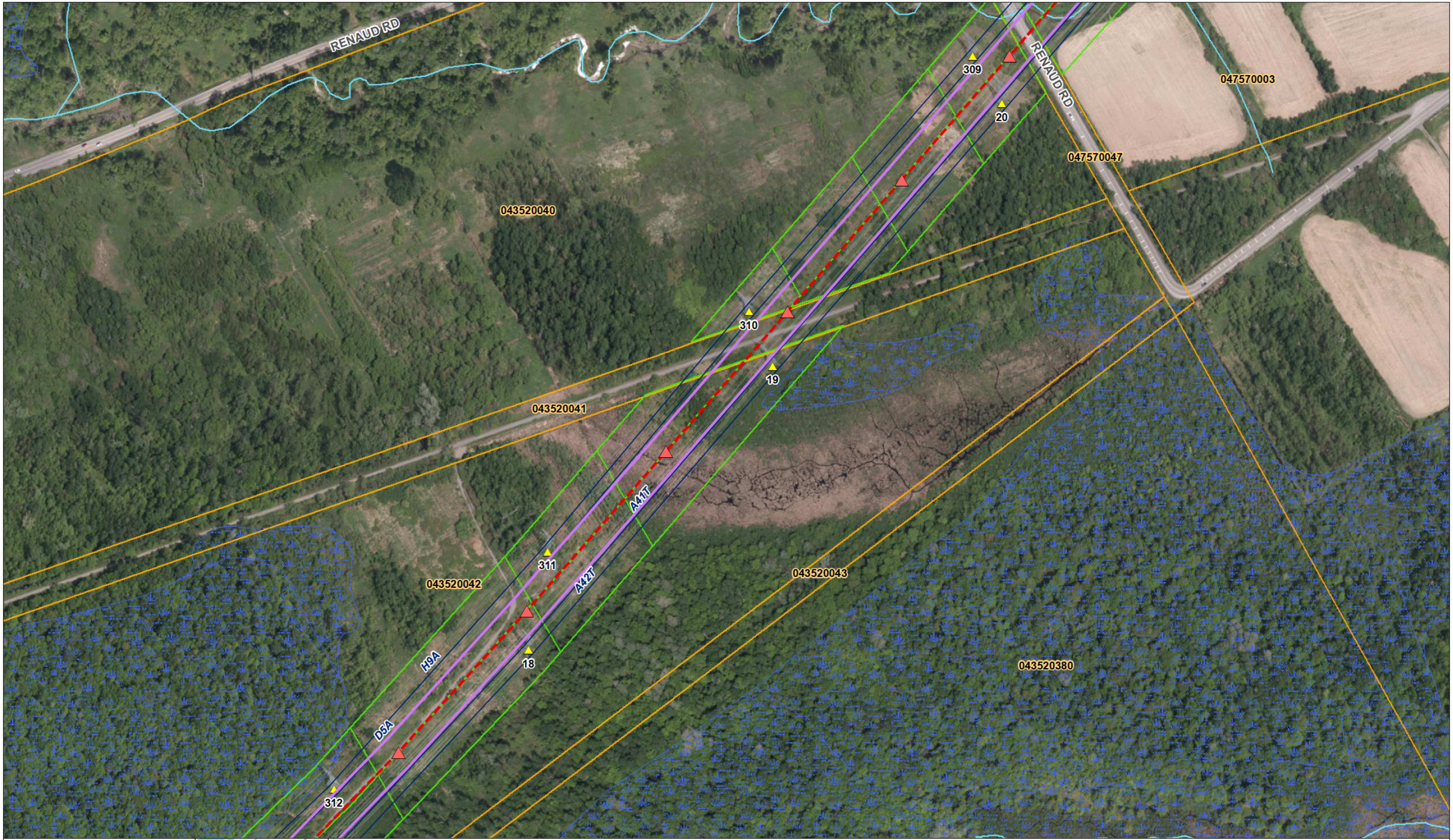

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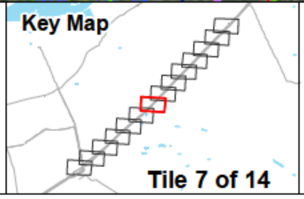

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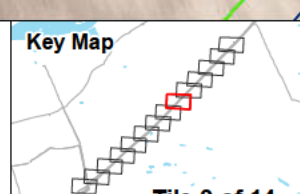

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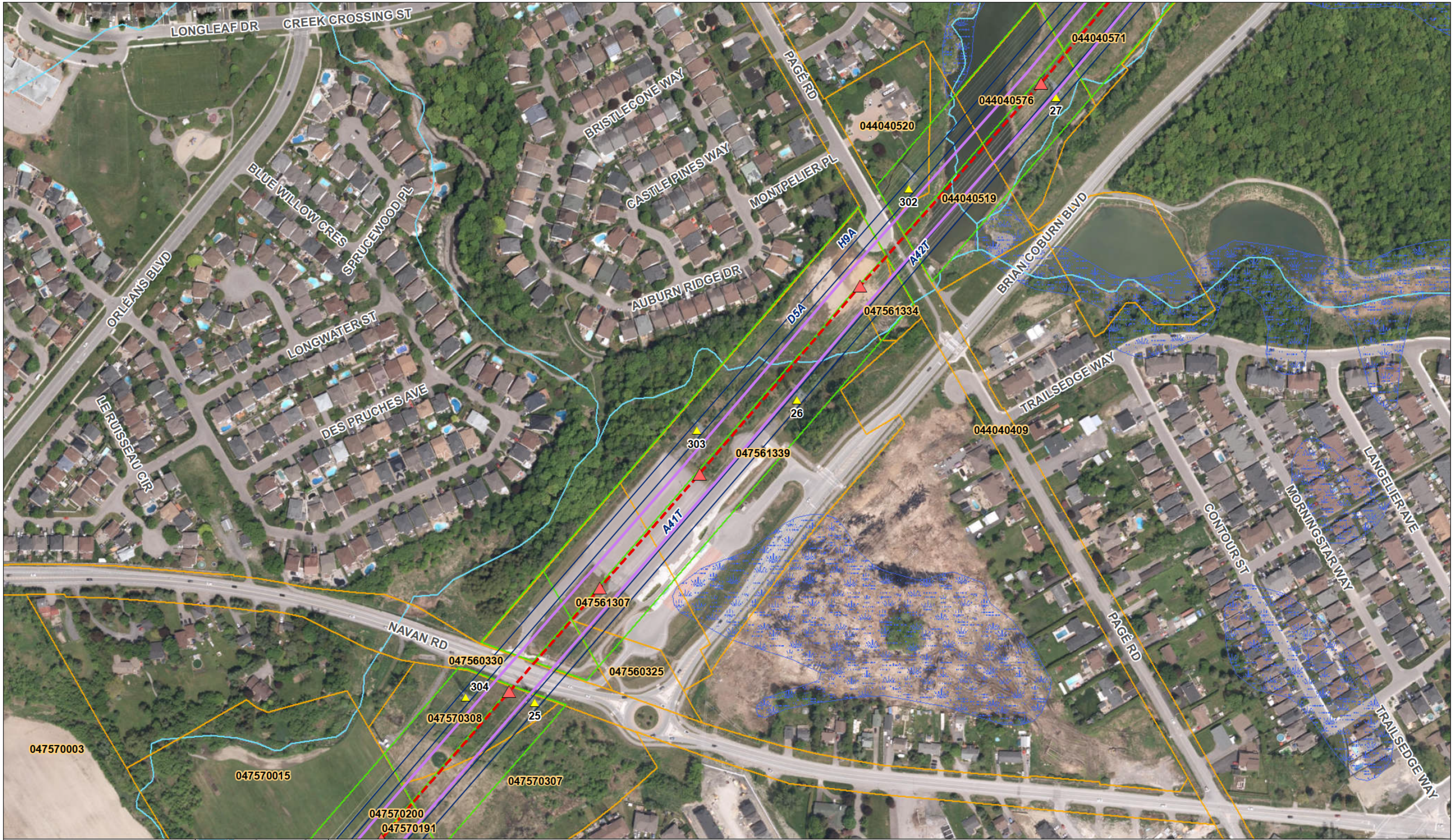

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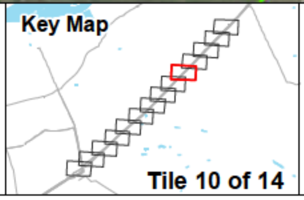

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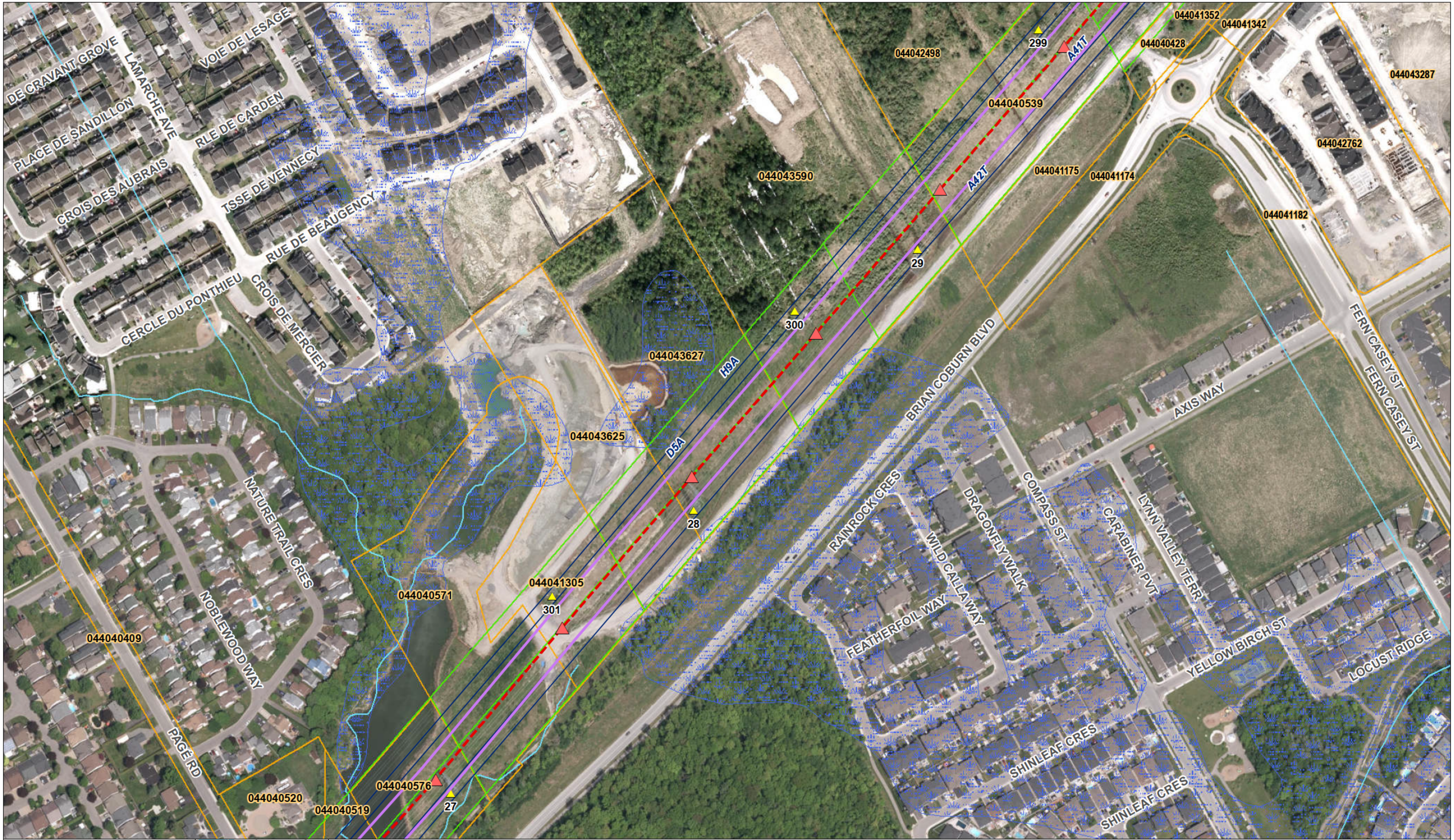

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Key Map
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Orleans Area Reinforcement Project
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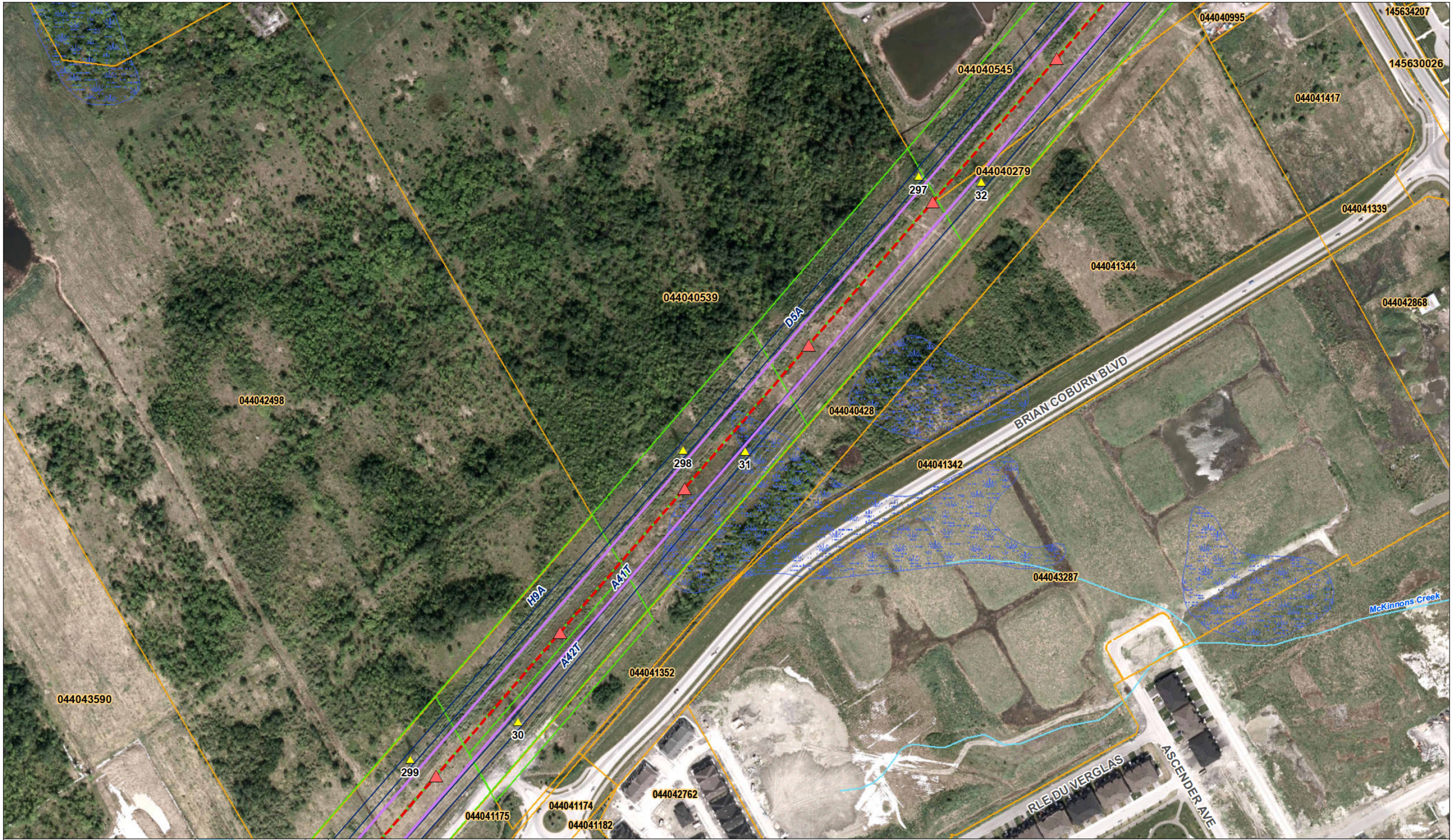

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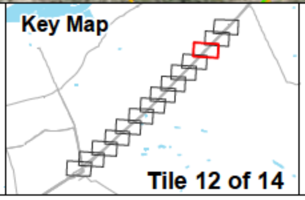

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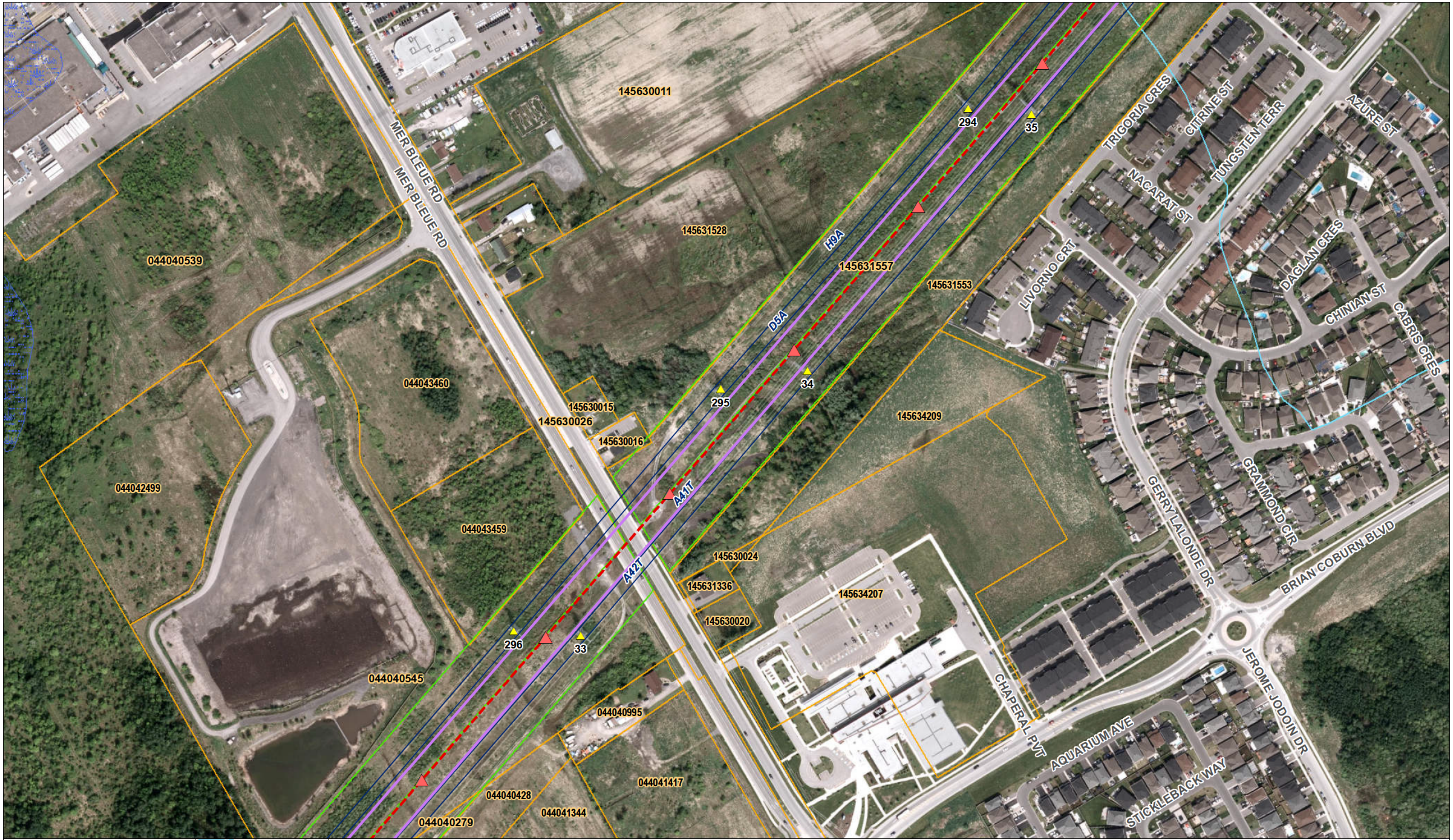

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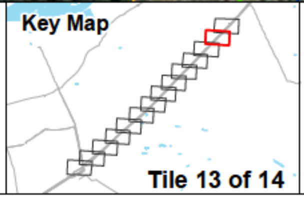

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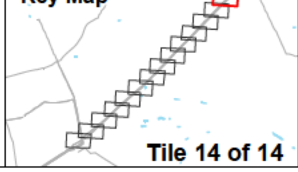

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Orleans Area Reinforcement Project
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LIST OF PROPERTIES AND PERMITS ASSOCIATED WITH THE PROJECT ROUTE

	PIN (Property Identification Number)	LEGAL DESCRIPTION	TYPE OF PROPERTY (Municipal, Private, Etc.)	Does Hydro One Require New or Updated Land Rights	RIGHTS REQUIRED	Where Agreement is Outstanding - Summary of Negotiations to Date	Owner(s)
		LAND RIGHTS ACQUISITIONS					
GL01	042620328	FIRSTLY: PART OF LOTS A AND 1 CONCESSION 6 RIDEAU FRONT (GLOUCESTER), PARTS 2, 3, 5, 6 AND 7 PLAN 4R14193; SUBJECT TO AN UNREGISTERED SEWER EASEMENT, IF ANY; SUBJECT TO AN EASEMENT IN FAVOUR OF THE BELL TELEPHONE COMPANY OF CANADA OVER PART 6 PLAN 4R14193 AS IN OT9018; TOGETHER WITH CT202222; TOGETHER WITH AN EASEMENT OVER PART OF LOTS 24 AND 25 CONCESSION 3, OTTAWA FRONT (GLOUCESTER), PART 1 PLAN 4R14193, SAVE & EXCEPT PARTS 1 TO 22 PLAN 4R16285 AS IN OC2188081; SUBJECT TO AN EASEMENT IN GROSS OVER PART LOT 1 CONCESSION 6 RIDEAU FRONT, PART 1 PLAN 4R33231 AS IN OC2287695; TOGETHER WITH AN EASEMENT OVER PART LOT 1 CONCESSION 6 RIDEAU FRONT, PARTS 1, 2 & 3 PLAN 4R34590 AS IN OC2523585; SUBJECT TO AN EASEMENT OVER PARTS 1, 4 & 6, 4R32591 AND PART 5 & 6, 4R14193 AS IN OC2367828 (PARTIALLY RELEASED BY OC2505397 & OC2666946); SECONDLY: PART OF LOTS A AND 1, CONCESSION 6, RIDEAU FRONT, PART 10 PLAN 4R8319; SUBJECT TO AN EASEMENT IN FAVOUR OF THE REGIONAL MUNICIPALITY OF OTTAWA-CARLETON OVER PART 6, PLAN 5R438 AS IN NS23681; TOGETHER WITH AN EASEMENT OVER PART OF LOTS 24 AND 25, CONCESSION 3, OTTAWA FRONT (GLOUCESTER), PART 1 PLAN 4R14193, SAVE & EXCEPT PARTS 1 TO 22 PLAN 4R16285 AS IN OC2188081; TOGETHER WITH AN EASEMENT OVER PART LOT 1 CONCESSION 6 (RIDEAU FRONT), PARTS 1, 2 & 3 PLAN 4R34590 AS IN OC2523585; THIRDLY: PART OF LOTS A AND 1, CONCESSION 6, RIDEAU FRONT, PART 33 PLAN 5R5597, SAVE & EXCEPT PARTS 7, 9 AND 10 PLAN 4R8319; TOGETHER WITH AN EASEMENT OVER PART LOT 1 CONCESSION 6 RIDEAU FRONT, PARTS 1, 2 & 3 PLAN 4R34590 AS IN OC2523585; FOURTHLY: PART OF LOTS 23 & 24 CONCESSION 3 OTTAWA FRONT (GLOUCESTER) PARTS 1 & 2 PLAN 4R29467; SUBJECT TO AN EASEMENT OVER PARTS 1 & 2 PLAN 4R29467 AS IN OC1780967; FIFTHLY: PART OF THE ROAD ALLOWANCE BETWEEN CONCESSION 3 OTTAWA FRONT AND CONCESSION 6 (CLOSED BY BYLAW AS IN OC2495378) RIDEAU FRONT (GLOUCESTER), PART 2 PLAN 4R34451; SUBJECT TO EASEMENT IN FAVOUR OF HYDRO OTTAWA LIMITED OVER PART 2, PLAN 4R34451 AS IN OC2495452; SUBJECT TO AN EASEMENT IN GROSS OVER PART 2, PLAN 4R34451 AS IN OC2495566; SIXTHLY: PART OF LOT A CONCESSION 6 RIDEAU FRONT (GLOUCESTER), PART 1 PLAN 4R34451; SUBJECT TO AN UNREGISTERED SEWER EASEMENT, IF ANY; TOGETHER WITH AS IN CT202222; TOGETHER WITH AN EASEMENT OVER PART LOTS A AND 1, CONCESSION 6 RIDEAU FRONT, PARTS 1, 4 & 6, 4R32591 AND PARTS 5 & 6, 4R14193 AS IN OC2367828; CITY OF OTTAWA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
GL03	042620157	PT LT A, CON 6RF ; PT LT 1, CON 6RF , BEING PARTS 19, 21, 23, 25, 26, 27, 5R5597 ; S/T CT209013,N644714 OTTAWA AND GLOUCESTER	Federal Government	Yes	Fixed-Term Easement	Offer Pending	[redacted]
GL05	43510021	PT LTS A & 1, CON 6RF , BEING PARTS 21,22,23,24,25, 27,28 & 29, 5R5893 , EXCEPT BLOCK C PLAN 711 ; S/T GL47255,GL62913,GL65553,N512167 GLOUCESTER	Federal Government	Yes	Fixed-Term Easement	Offer Pending	[redacted]
GL06	43510091	PT LTS 19 & 20, CON 4OF , BEING PARTS 1,2,3,4,5,6,7 & 8, 5R4471 ; S/T GL36192,GL36274,GL36290,GL47252, GL47253,GL47254,N512167 GLOUCESTER	Federal Government	Yes	Fixed-Term Easement	Offer Pending	[redacted]
GL07	43510094	PT LTS 16, 17 & 18, CON 4OF , BEING PART 4, 5R10 ; S/T GL36174,GL36187,GL36193,GL36199,GL36289,GL47247, GL47248,GL47249,GL47250,GL47251,N512167 GLOUCESTER	Federal Government	Yes	Fixed-Term Easement	Offer Pending	[redacted]
GL08	43520381	PT LT 15, CON 4OF , PART 1 & 2 , 5R6219 ; S/T GL47371 GLOUCESTER	Federal Government	Yes	Fixed-Term Easement	Offer Pending	[redacted]
GL09	43520380	PT LTS 11, 12, 13, 14 & 15, CON 4OF , PARTS 3, 4 & 5 , 5R6219 ; PART 2 , 5R11 ; S/T NS157686 ; S/T GL47371,GL48269 GLOUCESTER	Federal Government	Yes	Fixed-Term Easement	Offer Pending	[redacted]
GL10	43520043	PT RDAL BTN CONS 3OF&4OF GLOUCESTER, PARTS 7, 8, 9 & 20 5R428 (CLOSED BY OC2463445); GLOUCESTER	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
GL11	43520042	PT LTS 11, 12, 13, 14 & 15, CON 3OF , PARTS 5, 6, 10, 11, 12, 13 & 19 , 5R428 ; S/T GL47108,GL47109,GL47110, GL47111,GL47123,GL47124,GL48153 GLOUCESTER	Federal Government	Yes	Fixed-Term Easement	Offer Pending	[redacted]
GL13	43520040	LTS 30, 31 & 32, PL 695 ; PT LTS 11, 12, 13 & 14, CON 3OF , ALL BEING PARTS 14, 15, 16, 17 & 18 , 5R428 ; S/T GL47122,GL47123,GL47313,GL47700 GLOUCESTER	Federal Government	Yes	Fixed-Term Easement	Offer Pending	[redacted]
GL14	47570003	PT LTS 8, 9 & 10, CON 3OF , PTS 7 TO 12 & 14, 5R443, LYING S OF PTS 5 & 13, 5R14103;S/T CT163335 ; S/T GL36178,GL36182,GL36186,GL36261,GL36295,GL47105, GL47106,GL47107,GL47313,GL51608,N616414,N616415, N622934 GLOUCESTER	Federal Government	Yes	Fixed-Term Easement	Offer Pending	[redacted]
GL15	047570193	BLOCK 90, PLAN 4M1373, OTTAWA.	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
GL16	047570198	BLOCK 95, PLAN 4M1373, OTTAWA.	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
GL17	047570015	PT LT 7 CON 3OF GLOUCESTER PTS 4 & 5, 5R12581; S/T GL47180; GLOUCESTER	Private	Yes	Permanent Easement	Offer Pending	[redacted]
GL18	047570559	PART BLOCK 89, PLAN 4M-1373 DESIGNATED AS PARTS 1 AND 2, 4R-32360; SUBJECT TO AN EASEMENT AS IN GL36183; SUBJECT TO AN EASEMENT AS IN OC923784; SUBJECT TO AN EASEMENT IN GROSS AS IN OC1826749; SUBJECT TO AN EASEMENT OVER PART 2, 4R32360 IN FAVOUR OF PARTS 3, 4, 5 AND 6, 4R32360 AS IN OC2157875; TOGETHER WITH AN EASEMENT OVER PART 3, 4R32360 AS IN OC2157875; TOGETHER WITH AN EASEMENT OVER PART 5, 4R32360 AS IN OC2157875; SUBJECT TO AN EASEMENT OVER PARTS 1 AND 2, 4R32360 IN FAVOUR OF PARTS 3, 4, 5 AND 6, 4R32360 AS IN OC2157875; TOGETHER WITH AN EASEMENT OVER PARTS 3, 4, 5 AND 6, 4R32360 AS IN OC2157875; SUBJECT TO AN EASEMENT OVER PART 2, 4R32360 IN FAVOUR OF PARTS 9, 10, 11 AND 12, 4R32360 AS IN OC2157875; TOGETHER WITH AN EASEMENT OVER PART 9, 4R32360 AS IN OC2157875; SUBJECT TO AN EASEMENT OVER PARTS 1 AND 2, 4R32360 IN FAVOUR OF PARTS 9, 10, 11 AND 12, 4R32360 AS IN OC2157875; TOGETHER WITH AN EASEMENT OVER PARTS 9, 10, 11 AND 12, 4R32360 AS IN OC2157875; CITY OF OTTAWA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
GL19	47570199	BLOCK 96, PLAN 4M1373, OTTAWA.	Private	Yes	Permanent Easement	Offer Pending	[redacted]
GL20	047570558	PART BLOCK 89, PLAN 4M-1373 DESIGNATED AS PARTS 3, 4, 5 AND 6, 4R32360; SUBJECT TO AN EASEMENT AS IN GL36183; SUBJECT TO AN EASEMENT AS IN OC923784; SUBJECT TO AN EASEMENT IN GROSS AS IN OC1826749; SUBJECT TO AN EASEMENT IN GROSS OVER PART 5, 4R32360 AS IN OC1826752; TOGETHER WITH AN EASEMENT OVER PART 2, AND 8, 4R32360 AS IN OC2157875; SUBJECT TO AN EASEMENT OVER PART 3, 4R32360 IN FAVOUR OF PARTS 1, 2, 7 AND 8, 4R32360 AS IN OC2157875; SUBJECT TO AN EASEMENT OVER PART 5, 4R32360 IN FAVOUR OF PARTS 1, 2, 7 AND 8, 4R32360 AS IN OC2157875; TOGETHER WITH AN EASEMENT OVER PARTS 1, 2, 7 AND 8, 4R32360 AS IN OC2157875; SUBJECT TO AN EASEMENT OVER PARTS 3, 4, 5 AND 6, 4R32360 IN FAVOUR OF PARTS 1, 2, 7 AND 8, 4R32360 AS IN OC2157875; CITY OF OTTAWA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
GL21	047570191	BLOCK 88, PLAN 4M1373 SUBJECT TO AN EASEMENT AS IN GL36183 CITY OF OTTAWA	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
GL22	047570200	BLOCK 97, PLAN 4M1373, OTTAWA.	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
GL23	47570307	BLOCK 82, PLAN 4M1400; SUBJECT TO AN EASEMENT OVER PART 2, PLAN 4R21895 IN FAVOUR OF THE HYDRO ELECTRIC POWER COMMISSION OF ONTARIO AS IN GL36184; SUBJECT TO AN EASEMENT OVER PART 4 PLAN 4R21895 IN FAVOUR OF THE HYDRO ELECTRIC POWER COMMISSION OF ONTARIO AS IN GL47731; CITY OF OTTAWA	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]

	PIN (Property Identification Number)	LEGAL DESCRIPTION	TYPE OF PROPERTY (Municipal, Private, Etc.)	Does Hydro One Require New or Updated Land Rights	RIGHTS REQUIRED	Where Agreement is Outstanding - Summary of Negotiations to Date	Owner(s)
GL24	047570308	BLOCK 83, PLAN 4M1400; SUBJECT TO AN EASEMENT OVER PART 2, PLAN 4R21895 IN FAVOUR OF THE HYDRO ELECTRIC POWER COMMISSION OF ONTARIO AS IN GL36184; SUBJECT TO AN EASEMENT OVER PART 4 PLAN 4R21895 IN FAVOUR OF THE HYDRO ELECTRIC POWER COMMISSION OF ONTARIO AS IN GL47731; CITY OF OTTAWA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
GL25	047560325	PT LT 6 CON 3OF GLOUCESTER AS IN N282023; S/T GL36179; GLOUCESTER	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
GL26	047561307	BLOCK 205, PLAN 4M1133, OTTAWA.	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
GL27	047561339	PART LOT 6 CONCESSION 3 OTTAWA FRONT, GLOUCESTER, PARTS 1, 2, 3, 5, 6 & 7 EXPROPRIATION PLAN 0C1834435; SUBJECT TO AN EASEMENT OVER PART 6 EXPROPRIATION PLAN OC1834435 AS IN GL36179; SUBJECT TO AN EASEMENT OVER PARTS 3 & 5 EXPROPRIATION PLAN OC1834435 AS IN GL47179; CITY OF OTTAWA	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
GL28	047561334	PART OF LOT 6, CON 3 (OF), GLOUCESTER, PTS 13, 14 AND 16 PL 4R21265. OTTAWA. S/T GL36179, GL47179.	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
GL29	044040519	PART OF LOT 5, CONCESSION 3, OTTAWA FRONT, GLOUCESTER, BEING PARTS 1, 2, 3, 6, 7 AND 8 ON EXPROPRIATION PLAN OC837719. S/T GL36181, GL47347, N766202. OTTAWA.	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
GL30	044040520	PART OF LOT 5, CONCESSION 3, OTTAWA FRONT, BEING PARTS 1, 4, 5, 7 AND 8 ON PLAN 4R-21265. GL47347, N766202 CITY OF OTTAWA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
GL31	044040576	PART OF LOT 5 CONCESSION 3 GLOUCESTER (OTTAWA FRONT) BEING PARTS 2, 5, 6, 7, 8, 9 ON PLAN 4R-23526 SUBJECT TO AN EASEMENT IN FAVOUR OF THE HYDRO-ELECTRIC POWER COMMISSION OF ONTARIO OVER PART 5 AND 6 ON PLAN 4R23526 AS IN GL36198. SUBJECT TO AN EASEMENT	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
GL32	44040571	PART OF LOT 5, CONCESSION 3, OTTAWA FRONT (GLOUCESTER) BEING PARTS 3, 4 AND 10 TO 15 ON PLAN 4R-23526. SUBJECT TO AN EASEMENT OVER PARTS 4 AND 11 ON PLAN 4R-23526 AS IN GL36198. SUBJECT TO AN EASEMENT OVER PARTS 10, 12, 13 AND 14 AS IN GL47178. SUBJECT TO AN EASEMENT OVER PARTS 13 AND 14 ON PLAN 4R-23526 AS IN LT1198249 CITY OF OTTAWA	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
GL33	44041305	BLOCK 117, PLAN 4M1545. SUBJECT TO AN EASEMENT OVER PART 7 PLAN 4R7806 AS IN GL36198. SUBJECT TO AN EASEMENT OVER PART 2 PLAN 4R7806 AS IN GL47178. SUBJECT TO AN EASEMENT OVER PART 4 PLAN 4R14208 AS IN LT1198249; CITY OF OTTAWA	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
GL34	44043625	PART BLOCK 115, PLAN 4M1545, PART 1, PLAN 4R35301; PARTS 1-6, PLAN 4R35721; SUBJECT TO AN EASEMENT OVER PARTS 1-3, PLAN 4R35721 AS IN GL47177; SUBJECT TO AN EASEMENT OVER PARTS 4-6, PLAN 4R35721 AS IN GL36284; SUBJECT TO AN EASEMENT OVER PARTS 2 & 5, PLAN 4R35721 AS IN LT1170416; CITY OF OTTAWA	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
GL34B	44043267	BLOCK 115, PLAN 4M1545; SAVE AND EXCEPT PART 1, PLAN 4R35301, 4R35721 & 4R36948 SUBJECT TO AN EASEMENT OVER PART 2 PLAN 4R7900 AS IN GL36284. SUBJECT TO AN EASEMENT OVER PART 3 PLAN 4R7900 AS IN GL47177; SUBJECT TO AN EASEMENT OVER PARTS 1 AND 2 PLAN 4R14255 IN FAVOUR OF THE REGIONAL MUNICIPALITY OF OTTAWA-CARLETON AS IN LT1170416; SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 1-2 4R35301 AS IN OC2602264; CITY OF OTTAWA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
GL35	044043590	PART LOT 4, CONCESSION 3 OTTAWA FRONT, GLOUCESTER, PARTS 1, 2, 3, 4, 5, 6 AND 7 PLAN 4R32715; SAVE AND EXCEPT PARTS 47 & 48 ON 4R35499, SAVE AND EXCEPTPARTS 36 & 37 4R36862; SUBJECT TO AN EASEMENT OVER PARTS 5 AND 6 PLAN 4R32715 AS IN GL36180; SUBJECT TO AN EASEMENT OVER PARTS 3 AND 4 PLAN 4R32715 AS IN GL36296; SUBJECT TO AN EASEMENT OVER PART 7 PLAN 4R32715 AS IN GL47176; SUBJECT TO AN EASEMENT OVER PART 2 PLAN 4R32715 AS IN GL47312; SUBJECT TO AN EASEMENT OVER PART 5 PLAN 4R32715 AS IN N764971; SUBJECT TO AN EASEMENT OVER PART 4 PLAN 4R32715 AS IN N767035; CITY OF OTTAWA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
GL36	044040539	PART OF LOTS 1,2 & 3 CONCESSION 3 OTTAWA FRONT GLOUCESTER PARTS 1 AND 9 TO 23 PLAN 4R19308, SAVE AND EXCEPT PART 1 ON 4R19897, SAVE AND EXCEPT PARTS 3 TO 7 ON 4R22886, SAVE AND EXCEPT PART 2 ON 4R22628, SAVE AND EXCEPT PART 1 ON 4R22738, OTTAWA S/T EASEM	Private	Yes	Permanent Easement	Offer Pending	[redacted]
GL37	044040279	PT LT 1 CON 3OF GLOUCESTER PTS 1 & 2, 4R14216; S/T GL36190, GL47243; GLOUCESTER	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
GL38	044040545	PART OF LOT 1 CONCESSION 3OF GLOUCESTER PARTS 6,7 & 8 ON 4R22552 AND PARTS 3 TO 10 ON 5R14793, OTTAWA S/T GL36188, GL36190, GL36254, GL47243, OTTAWA SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 2, 3, 4, 5, 4R-29373 AS IN OC1775103	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
CU01	145631557	BLOCK 27, PLAN 4M1557 SUBJECT TO AN EASEMENT OVER PARTS 11 AND 12 ON PLAN 50R6820 AS IN CU16026 SUBJECT TO AN EASEMENT OVER PART 1 ON PLAN 4R18081 IN FAVOUR OF THE CITY OF OTTAWA AS IN OC154823 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 1 AND 5 ON PLAN 4R27358 AS IN OC1526530 SUBJECT TO AN EASEMENT IN GROSS OVER PART 1 ON PLAN 4R27358 AS IN OC1663575 SUBJECT TO AN EASEMENT AS IN CU18905 CITY OF OTTAWA	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
CU02	145630011	PART OF LOT 1, CONCESSION 11, CUMBERLAND, BEING PARTS 1 AND 4 ON PLAN 50R-6958, SAVE AND EXCEPT PART 20 ON PLAN 4R-14303 SUBJECT TO AN EASEMENT OVER PART 4 ON PLAN 50R-6958 IN FAVOUR OF THE HYDRO-ELECTRIC POWER COMMISSION OF ONTARIO AS IN CU18950 SUBJECT TO AN EASEMENT IN GROSS OVER PART 1 ON PLAN 4R-27322 AS IN OC1535070 SUBJECT TO AN EASEMENT IN GROSS OVER PART 1 PLAN 4R27322 AS IN OC1658150 CITY OF OTTAWA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
CU03	145631554	BLOCK 24, PLAN 4M1557; SUBJECT TO AN EASEMENT IN FAVOUR OF THE CITY OF OTTAWA AS IN OC154823; SUBJECT TO AN EASEMENT IN GROSS AS IN OC1526530; SUBJECT TO AN EASEMENT IN GROSS AS IN OC1663575 SUBJECT TO AN EASEMENT AS IN CU16091 SUBJECT TO AN EASEMENT AS IN CU18905 CITY OF OTTAWA	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
CU04	145631556	BLOCK 26, PLAN 4M1557; SUBJECT TO AN EASEMENT IN FAVOUR OF THE CITY OF OTTAWA AS IN OC154823; SUBJECT TO AN EASEMENT IN GROSS AS IN OC1526530; SUBJECT TO AN EASEMENT IN GROSS AS IN OC1663575 SUBJECT TO AN EASEMENT AS IN CU16091 SUBJECT TO AN EASEMENT AS IN CU18905 CITY OF OTTAWA	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
CU05	145630674	PART OF LOT 1, CONCESSION 11 CUMBERLAND BEING PARTS 8 TO 19 AND 24 TO 28 ON PLAN 4R14303; SUBJECT TO AN EASEMENT IN FAVOUR OF THE HYDRO ELECTRIC POWER COMMISSION OF ONTARIO OVER PARTS 9-12, 16 TO 18 AND 25 TO 27 ON PLAN 4R-14303 AS IN CU16009. SUBJECT TO AN EASEMENT IN FAVOUR OF THE HYDRO-ELECTRIC POWER COMMISSION OF ONTARIO OVER PARTS 18, 19, 27 AND 28 ON PLAN 4R-14303 AS IN CU18950. SUBJECT TO AN EASEMENT IN FAVOUR OF THE REGIONAL MUNICIPALITY OF OTTAWA-CARLETON OVER PART 13 ON PLAN 4R-14303 AS IN RR76534 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 1, 2, 3, 4 AND 5 ON PLAN 4R28762 AS IN OC1694861 CITY OF OTTAWA	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]

	PIN (Property Identification Number)	LEGAL DESCRIPTION	TYPE OF PROPERTY (Municipal, Private, Etc.)	Does Hydro One Require New or Updated Land Rights	RIGHTS REQUIRED	Where Agreement is Outstanding - Summary of Negotiations to Date	Owner(s)
NO/LIMITED RIGHTS REQUIRED							
GL02	042620327	PART OF LOTS A AND 1 CONCESSION 6 RIDEAU FRONT, PART 4 PLAN 4R14193, EXCEPT PART 1 PLAN 4R34451; SUBJECT TO AN UNREGISTERED SEWER EASEMENT, IF ANY; TOGETHER WITH AN EASEMENT OVER PART LOTS A AND 1, CONCESSION 6 RIDEAU FRONT, PARTS 1, 4 & 6, 4R32591 AND PARTS 5 & 6, 4R14193 AS IN OC2367828 PARTIALLY RELEASED BY OC2666946; TOGETHER WITH AN EASEMENT OVER PART LOTS A AND 1, CONCESSION 6 RIDEAU FRONT, PARTS 2, 3, 5, 6 AND 7 PLAN 4R14193 AND PART 10 PLAN 4R8319 AS IN OC2505395; CITY OF OTTAWA	Railway Crossing	No	Crossing Permit	N/A	[redacted]
GL04	43510014	FIRSTLY PT LT 22 CON 3OF GLOUCESTER; PT LT 23 CON 3OF GLOUCESTER; PT RDAL BTN LT 22 & 23 CON 3OF & LT A CON 6RF GLOUCESTER; PT LT A CON 6RF GLOUCESTER; PT LT 1 CON 6RF GLOUCESTER ; PT LT 2 CON 3OF GLOUCESTER; PT LT 3 CON 6RF GLOUCESTER AS IN NS108952; SECONDLY PT RDAL BTN LT 23 CON3OF & LT A CON 6RF GLOUCESTER CLOSED BY ORDER-IN-COUNCIL N380375, PT 33, 5R4735; PT LT 2 CON 6RF GLOUCESTER PT 4 & 6, 5R4735, BEING KING'S HIGHWAY #417 LYING S OF S LIMIT PT 17, 5R386 & N OF S LIMIT PT 2 & 3, 5R4735; S/T GL62913; GLOUCESTER	Provincial Lands	Yes	Crossing Permit	N/A	[redacted]
GL12	43520041	PT LTS 11, 12, 13, 14 & 15, CON 3OF , AS IN N552606 ; S/T N552606 ; GLOUCESTER	Federal Government	Yes	Crossing Permit	N/A	[redacted]
	042620156	PT LT A, CON 6RF ; PT LT 1, CON 6RF , BEING PART 15 & 16, 5R4735 ; S/T N480682 OTTAWA/GLOUCESTER	Bill 58	No	Rights in Place (Bill 58)	N/A	[redacted]
	43510149	PT LT 2 CON 6RF GLOUCESTER BEING PARTS 1 & 2, 5R13953, GL56339 (SECONDLY) & OT21958, EXCEPT GL68347 & PT 1, 4R9759; PT LT 3 CON 6RF GLOUCESTER AS IN GL58815, EXCEPT PTS 86 & 87, 5R4833; S/T NS48905; OTTAWA/GLOUCESTER	Owned	No	Owned by Hydro One	N/A	[redacted]
	042620158	PT LT 1, CON 6RF , FIRSTLY, PTS 4 TO 11 & 24, 5R5597; SECONDLY, AS IN OT42709 & OT38741 (2NDLY) EXCEPT 5R5597, ALL BEING THE LANDS LYING BTN PTS 5 & 6 AND 7 & 11, 5R5597; S/T CT209013, CT212893, NS27803, OT9018 SUBJECT TO AN EASEMENT OVER PARTS 1, 2 & 3,	Owned	No	Owned by Hydro One	N/A	[redacted]
	145630638	PART LOT 1 CONCESSION 11 CUMBERLAND PART 5 PLAN 4R26747 CITY OF OTTAWA	Owned	No	Owned by Hydro One	N/A	[redacted]
	145630640	PART LOT 1 CONCESSION 11 CUMBERLAND PART 2 PLAN 4R26747 CITY OF OTTAWA	Owned	No	Owned by Hydro One	N/A	[redacted]
	42620162	FIRSTLY, PT LT 15 CON 4OF GLOUCESTER; PT LT 16 CON 4OF GLOUCESTER; PT LT 15 CON 5OF GLOUCESTER; PT LT 16 CON 5OF GLOUCESTER AS IN CT119526; PT RDAL BTN CON 3 & 4OF GLOUCESTER; PT RDAL BTN CONS 4OF&5OF GLOUCESTER; PT RDAL BTN CONS 5 & 6OF GLOUCESTER; RDAL	Road Allowance	No	Rely on S.41(1) of the Electricity Act	N/A	[redacted]
	043510418	PT RDAL BTN LT A, 1, 2, 3, 4, 5 & 6 CON 6 RIDEAU FRONT & LT 20 CON 4 OTTAWA FRONT & LT 20 CON 5 OTTAWA FRONT GLOUCESTER & 10 FOOT WIDENING PL 711 GLOUCESTER (AKA BASE LINE RD) LYING S OF INNES RD & N OF PART 69, 5R4833; EXCEPT PART 1 4R28676 CITY OF OTTA	Road Allowance	No	Rely on S.41(1) of the Electricity Act	N/A	[redacted]
	043520044	FIRSTLY, PT LT 15 CON 4OF GLOUCESTER; PT LT 16 CON 4OF GLOUCESTER; PT LT 15 CON 5OF GLOUCESTER; PT LT 16 CON 5OF GLOUCESTER AS IN CT119526; PT RDAL BTN CON 3 & 4OF GLOUCESTER; PT RDAL BTN CONS 4OF&5OF GLOUCESTER; PT RDAL BTN CONS 5 & 6OF GLOUCESTER; RDAL	Road Allowance	No	Rely on S.41(1) of the Electricity Act	N/A	[redacted]
	047570047	RDAL BTN LTS 10&11 CON 3OF GLOUCESTER BTN PT 3, 5R14811 & FOURTH LINE RD; GLOUCESTER	Road Allowance	No	Rely on S.41(1) of the Electricity Act	N/A	[redacted]
	047560330	FIRSTLY, PT LT 6 CON 3OF GLOUCESTER AS IN GL73158, PT 2, 5R11075; PT LT 7 CON 3OF GLOUCESTER AS IN GL73158, PART 1, 5R3198, PART 2, 5R8473, PART 1, 5R6067, PART 1, 5R2437; PT LT 8 CON 3OF GLOUCESTER AS IN GL75078; PT LT 9 CON 3OF GLOUCESTER PT 16, 5R1410	Road Allowance	No	Rely on S.41(1) of the Electricity Act	N/A	[redacted]
	044040409	FIRSTLY; ROAD ALLOWANCE BETWEEN LOTS 5 AND 6 CONCESSION 3, OTTAWA FRONT, GLOUCESTER; PART LOT 5 COCNESSION 3, OTTAWA FRONT, GLOUCESTER, PART 1 PLAN 5R11047; PART LOT 5 CONCESSION 3, OTTAWA FRONT, GLOUCESTER, PART 62 PLAN 5R4980; PART LOT 5 CONCESSION 3,	Road Allowance	No	Rely on S.41(1) of the Electricity Act	N/A	[redacted]
	145630026	FIRSTLY; ROAD ALLOWANCE BETWEEN LOTS 5 AND 6 CONCESSION 3, OTTAWA FRONT, GLOUCESTER; PART LOT 5 COCNESSION 3, OTTAWA FRONT, GLOUCESTER, PART 1 PLAN 5R11047; PART LOT 5 CONCESSION 3, OTTAWA FRONT, GLOUCESTER, PART 62 PLAN 5R4980; PART LOT 5 CONCESSION 3,	Road Allowance	No	Rely on S.41(1) of the Electricity Act	N/A	[redacted]

EARLY ACCESS AGREEMENT

THIS AGREEMENT made in duplicate the _________day of _______________202__

Between:

OWNERS NAMES
(hereinafter referred to as the "Grantor")
OF THE FIRST PART

--- and ---

HYDRO ONE NETWORKS INC.

(hereinafter referred to "HONI")
OF THE SECOND PART

WHEREAS the Grantor is the owner in fee simple and in possession of certain lands legally described as LEGAL DESCRIPTION as in PIN NUMBER (LT), (the "Lands").

WHEREAS HONI in connection with the Orleans Area Reinforcement Project (the "Project") desires the right to enter onto a portion of the Lands in order to carry out all necessary real estate, environmental, and engineering studies and testing including but not limited to borehole testing, archaeological studies, soil assessments, property appraisals and surveys on, over and upon the Lands associated with the Project.

WHEREAS the Grantor is agreeable in allowing HONI to enter onto a portion of the Lands for the purpose of all necessary studies and testing on, over and upon the Lands, subject to the terms and conditions contained herein.

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the sum of TWO DOLLARS ($2.00) now paid by HONI to the Grantor, and the mutual covenants herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. The Grantor hereby grants, conveys and transfers to HONI in, over, along and upon that part of the Lands highlighted in yellow as shown in Schedule "A" attached hereto (the "Preferred Route"), the rights and privileges as follows:

(a) for the servants, agents, contractors and workmen of HONI at all times with all necessary vehicles and equipment to pass and repass over the Preferred Route for the purpose of real estate, environment and engineering studies and testing associated with the Project, subject to payment of compensation for damages including payment for crop land out of production caused thereby;

(b) to cut and remove all trees, brush and other obstructions made necessary by the exercise of the rights granted hereunder with prior consent of the Grantor, subject to payment of compensation for damages.

2. The term of this Agreement and the permission granted herein shall be two (2) years (the "Initial Term") commencing on the Agreement date written above.

3. After execution of this Agreement by all parties, HONI shall pay to the Grantor the amount of XXXX DOLLARS ($XXXX.00), which is compensation for the permission granted herein for the Initial Term.

4. HONI may, in its sole discretion, and upon 5 days prior written notice to the Grantor, extend the Initial Term for an additional term of one (1) year on the same terms and conditions contained herein save for this right to extend and section 3 herein (the "Extended Term").

5. In the event that HONI exercises its right to extend the Initial Term, HONI shall pay to the Grantor the amount of XXXX DOLLARS ($XXXX.00), which is compensation for the permission granted herein for the Extended Term.

6. Upon the expiry of the Term or any extension thereof, HONI shall repair any physical damage to the Preferred Route and/or Lands resulting from HONI's use of the Preferred Route and the permission granted herein; and, shall restore the Preferred Route to its original condition so far as possible and practicable.

7. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Preferred Route shall be at the sole risk of HONI and the Grantor shall not be liable for any loss or damage or injury (including loss of life) to them or it however occurring except and to the extent to which such loss, damage or injury is caused by the negligence or willful misconduct of the Grantor.

8. HONI agrees that it shall indemnify and save harmless the Grantor from and against all claims, demands, costs, damages, expenses and liabilities (collectively the "Costs") whatsoever arising out of HONI's presence on the Preferred Route or of its activities on or in connection with the Preferred Route arising out of the permission granted herein except to the extent any of such Costs arise out of or are contributed to by the negligence or willful misconduct by the Grantor.

9. Notices to be given to either party shall be in writing, personally delivered or sent by registered mail (except during a postal disruption or threatened postal disruption), telegram, electronic facsimile to the applicable address set forth below (or to such other address as such party may from time to time designate in such manner):

TO HONI:

Hydro One Networks Inc.
Real Estate Services
1800 Main Street East
Milton, Ontario L9T 7S3

Attention: Real Estate Acquisitions
Tel: 905-875-2508
Fax: 905-878-8356

TO GRANTOR:

Address:

Attention:
Tel:

Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5^{th}) business day following the date on which it was sent. Any notice sent by telegram, electronic facsimile or shall be deemed to have been validly and effectively given on the Business Day next following the day on which it was sent. "Business Day" shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario.

10. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable herein. The parties hereto submit themselves to the exclusive jurisdiction of the Courts of the Province of Ontario.

11. Any amendments, modifications or supplements to this Agreement or any part thereof shall not be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of this Agreement.

12. The burden and benefit of this Agreement shall run with the Lands and everything herein contained shall operate to the benefit of, and be binding upon, the respective heirs; successors, permitted assigns and other legal representatives, as the case may be, or each of the Parties hereto.

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the day and year first above written.

SIGNED, SEALED AND DELIVERED
In the presence of)
)
)
)
)
______________________________) ______________________________
(seal)
Print Name of Witness PARTY TO

SIGNED, SEALED AND DELIVERED
In the presence of)
)
)
)
)
______________________________) ______________________________
(seal)
Print Name of Witness

SIGNED, SEALED AND DELIVERED
In the presence of)
)
)
)
)
______________________________) ______________________________
(seal)
Print Name of Witness

HYDRO ONE NETWORKS INC.

Per:
____
Name:

Title:

I have authority to bind the Corporation

SCHEDULE "A"

PROPERTY SKETCH

Conceptual sketch only.

OPTION TO PURCHASE A LIMITED INTEREST – EASEMENT

OPTION AGREEMENT - EASEMENT

THIS OPTION AGREEMENT made as of the __________ day of _________________, 20__ (the "**Agreement Date**").

B E T W E E N:

«OWNER_1_NAME_FOR_LETTERS» & «OWNER_2_NAME_FOR_LETTERS» & «OWNER_3_NAME_FOR_LETTERS»

(hereinafter collectively called the "**Owner**")

OF THE FIRST PART

- and -

HYDRO ONE NETWORKS INC.

(hereinafter called "**Hydro One**")

OF THE SECOND PART

- and -

SPOUSE NAME

(hereinafter collectively called the "**Spouse**") This section is only filled if the spouse is not on title

OF THE THIRD PART

RECITALS:

A. The Owner is the owner of the lands and premises described in Schedule "A" (the "**Lands**");

B. The Owner has agreed to grant to Hydro One for the consideration and on the terms and conditions set out herein and attached hereto as Schedule "B" (the "**Standard Terms and Conditions**") an option to purchase a right-of-way and easement in, on, over, under, across and through (the "**Easement**") that portion of the Lands described and shown on Schedule "A-1" attached hereto (the "**Easement Lands**"), the terms of which are more particularly set out in the Transfer and Grant of Easement (the "**Easement Agreement**") attached hereto as Schedule "C".

C. Hydro One has entered into an agreement with the Owner having a date the same as this Option Agreement (the "**Compensation and Incentive Agreement**").

NOW THEREFORE, the parties hereby agree as follows:

1. **<u>GRANT OF OPTION</u>**

In consideration of the sum of **XXXXX ($XXXXX)** of lawful money of Canada paid by Hydro One to the Owner, the receipt and sufficiency of which is hereby acknowledged by the Owner, (the **"Option Payment"**) the Owner hereby grants to Hydro One an irrevocable option (the "**Option**"), to purchase the Easement upon and subject to the terms and conditions set out herein, the Standard Terms and Conditions and the Schedules hereto.

2. **<u>PURCHASE PRICE</u>**

In accordance with the terms and conditions set out herein, the Standard Terms and Conditions and the Schedules hereto, Hydro One agrees to pay to or to the order of the Owner the amount of **XXXX Dollars ($ ●)** for the Easement Lands (the "**Purchase Price**") on the Closing Date.

IN WITNESS WHEREOF the parties hereto have duly executed this Option Agreement as of the Agreement Date.

WITNESS:	**OWNER:**
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_1_name_for_letters»**
Address:	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_2_name_for_letters»**
Address:	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_3_name_for_letters»**
Address:	

WITNESS:	The spouse of the Owner hereby consents to this Agreement
	SPOUSE OF OWNER:
	l/s
Name: Real Estate Representative	Name: **Property Owner Spouse Name**
Address:	

HYDRO ONE NETWORKS INC.

Per: ______________________________

Name:

Title:

HYDRO ONE
HST 870865821RT0001

I have authority to bind the Corporation

SCHEDULE "A"
LEGAL DESCRIPTION

«LEGAL_DESCRIPTION»

SCHEDULE "A-1"
EASEMENT LANDS

Legal description to be determined by deposited Reference Plan; Easement Lands shown outlined in green.

****NOTE – Sketch shall be replaced by servient lands description once applicable Reference Plan is deposited.**

Screenshot of ortho map with tower placements here

SCHEDULE "B"
STANDARD TERMS AND CONDITIONS

1. **EXERCISE OF OPTION**

The Option shall be open for exercise at any time from the Agreement Date until the 2nd anniversary of the Agreement Date, as same may have been extended in accordance with the terms hereof, (the "**Option Term**"), by providing written notice to the Owner (the "**Exercise Notice**"), after which time, subject to Section 2, this Option Agreement shall be null and void and no longer binding upon either of the parties. If the Option is exercised within the Option Term, then this Option Agreement shall become a binding agreement for the purchase and sale of the Easement and this Option Agreement shall be completed on the terms set out herein.

2. **EXTENSION OF OPTION TERM**

At any time during the Option Term, Hydro One may, by written notice delivered to the Owner prior to the expiration of the Option Term, as same may have been extended, extend the Option Term with respect to the Lands for one (1) additional period of one (1) year, provided that upon such election, Hydro One pays to the Owner the amount of $XXXXX in consideration for the extension of the Option Term.

3. **PURCHASE PRICE**

(a) Hydro One shall pay the Purchase Price to or to the order of the Owner by way of a single payment by uncertified cheque or electronic funds transfer on the Closing Date (as hereinafter defined).

(b) The Owner acknowledges receipt of an appraisal report commissioned by Hydro One and, prepared by an external, independent appraiser with the Accredited Appraiser Canadian Institute ("AACI") designation, (the "**HONI Appraisal**").

(c) The parties acknowledge that the Purchase Price is based on a purchase price per acre as set out in Schedule "B" of the Compensation and Incentive Agreement and the actual area of the Easement Lands shall be confirmed by a survey to be prepared by Hydro One in accordance with section 9 herein, and in the event the surveyed area of the Easement Lands is greater than as provided for in Schedule "B" of the Compensation and Incentive Agreement, and Purchase Price shall be adjusted accordingly.

4. **CLOSING**

The transaction of purchase and sale contemplated by this Option Agreement shall, subject to resolution of any title issues identified by Hydro One, be completed on the date that is ninety (90) days after Hydro One delivers the Exercise Notice to the Owner or on such earlier date as Hydro One, through its solicitors, may elect (the **"Closing Date"**). If the Closing Date is a date on which the Land Registry Office (the "**Land Registry Office**") in which the Lands are registered is closed, the Closing Date shall be on the next following day when such Land Registry Office is open. In the event that there is a delay in the completion of the transaction beyond the Closing Date as established by Hydro One upon delivery of the Exercise Notice that arises through no fault of Hydro One, then Hydro One shall not be responsible for any resulting delay in the Closing Date.

5. **ACKNOWLEDGEMENT AND DIRECTION**

The Owner and, if applicable, the Spouse, acknowledges and agrees that execution of the Option Agreement shall constitute execution of the Acknowledgement and Direction attached as Schedule "D" to the Option Agreement (the "**Acknowledgement and Direction**") authorizing Hydro One and its solicitors to register the Option and subsequent Easement on title to the Lands. Hydro One covenants and agrees to hold the Acknowledgement and Direction in escrow until Hydro One has paid the Purchase Price at which time the executed Acknowledgement and Direction and Option shall be released from escrow and may be acted upon by Hydro One.

6. **REGISTRATION OF EASEMENT**

The Owner acknowledges and agrees that Hydro One will register the Easement on title to the Lands on the Closing Date pursuant hereto and the Acknowledgement and Direction. Hydro

One will provide notice to the Owner within a reasonable period of time after the Closing Date of the registration particulars of the Easement.

7. **RIGHT TO TRANSFER**

The Owner covenants and agrees with Hydro One that it has the right to grant the Easement without restriction and that Hydro One will quietly possess and enjoy the Easement Lands.

8. **INSPECTION PERIOD AND EARLY ACCESS PERIOD**

(a) The Owner agrees and consents to Hydro One, its respective officers, employees, agents, contractors, sub-contractors, surveyors, workers and permittees or any of them entering on, exiting and passing and repassing in, on, over, along, upon, across, through and under the Easement Lands and so much of the Lands as may be reasonably necessary at all reasonable times from the Agreement Date until the later of the expiration of the Option Term (as same may be extended) and the Closing Date, with or without all plant, machinery, material, supplies, vehicles, and equipment, for all purposes necessary or convenient to conduct such inspections, tests, audits, reports as Hydro One sees fit in connection with the acquisition, exercise or enjoyment of the Easement. Hydro One shall restore the Lands to their prior condition so far as reasonably possible following such inspections, tests, audits and reports.

(b) The Owner agrees and consents to Hydro One, its respective officers, employees, agents, contractors, sub-contractors, surveyors, workers and permittees or any of them entering on, exiting and passing and repassing in, on, over, along, upon, across, through and under the Easement Lands and so much of the Lands as may be as reasonably necessary at all reasonable times from date Hydro One delivers the Exercise Notice to commence construction activities on the Easement Lands. Hydro One shall restore the Lands to their prior condition so far as reasonably possible in the event that the purchase transaction contemplated by this Option Agreement is not completed as contemplated herein.

9. **SURVEY/REFERENCE PLAN**

Hydro One agrees to obtain and register, at its sole expense, any new Reference Plan with respect to the Easement Lands that may be required by Hydro One for completion of this Option Agreement.

10. **INCOME TAX ACT**

The Owner represents and warrants and covenants that the Owner is not now and on Closing will not be a non-resident of Canada within the meaning of the *Income Tax Act (Canada).*

11. **HARMONIZED SALES TAX**

The Owner and Hydro One acknowledge and agree that the grant of easement which is proposed under this Option Agreement constitutes a purchase and sale transaction of an interest in real property, and therefore, in conformance with subsections 221(2) and 228(4) of the *Excise Tax Act* R.S.C. 1985, c E-15, as amended ("the Act"), Hydro One shall report and pay to the Receiver General for Canada the Harmonized Sales Tax ("HST") applicable to the purchase and sale of the Easement. For the purposes of this section 11, Hydro One shall warrants that it is an HST registrant in good standing under the Act, that its HST registration number is 870865821RT0001, and that it is acquiring the Easement for use primarily in the course of its commercial activities.

12. **NOTICE OF OPTION**

Hydro One may, in its sole discretion and at its sole expense register this Option Agreement or notice thereof on title to the Lands.

13. **NO OTHER RIGHTS**

The Owner covenants and agrees with Hydro One that the Owner shall not grant, create or transfer any easement, right, covenant, restriction, privilege, permission, or other agreement in, through, under, over or in respect of the Easement Lands prior to the registration of the Easement without the prior written consent of Hydro One.

14. **PRIOR ENCUMBRANCES**

The Owner hereby grants Hydro One permission, should Hydro One elect in its sole discretion, to approach any encumbrancer having an interest in the Easement Lands in priority to the Easement Agreement and to obtain (in registrable form) and register all necessary consents, postponements or subordinations from all current and future encumbrancers having an interest in the Easement Lands in priority to the Easement Agreement or this Option Agreement consenting, postponing or subordinating such encumbrance and their respective rights, title and interest to the Easement and this Option Agreement or to place the Easement Agreement and this Option Agreement in first priority on title to the Easement Lands.

15. **TIME OF ESSENCE**

Time shall in all respects be of the essence hereof; provided, however, that the time for doing or completing any matter provided for herein may be extended or abridged by an agreement in writing between the parties or their respective counsel.

16. **NOTICES**

Notices to be given to either party shall be in writing, and will be sent via electronic mail ("email"), personally delivered or sent by registered mail (except during a postal disruption or threatened postal disruption), telegram, electronic facsimile or other similar means of prepaid recorded communication to the applicable address set forth below (or to such other address as such party may from time to time designate in such manner):

HYDRO ONE:

Hydro One Networks Inc.
Facilities and Real Estate
P.O. Box 4300
Markham, Ontario L2R 5Z5

185 Clegg Road
Markham, Ontario L3G 1B7

Attention:
Fax: (905) 946-6242

with a copy to its solicitors,

Barriston LLP
90 Mulcaster Street
Barrie, ON L4M 4Y5

Attention: Jim McIntosh
Fax: 705-721-4025

OWNER:

«Owner_1_name_for_letters»
«Owner_2_name_for_letters»
«Owner_3_name_for_letters»
«STREET_NUM» «STREET_NAME1»
«MUNICIPALITY», «PROVINCE»
«POSTAL_CODE»

«SAP_Phone_Number»
«SAP_email_address»

with a copy to their solicitors,

Solicitors Name
Solicitors Address 1
Solicitors Address 2
Solicitors Address 3

Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5^{th}) Business Day following the date on which it was sent. Any notice sent by email, telegram, electronic facsimile or other similar means of prepaid recorded communication shall be deemed to have been validly and effectively given on the Business Day next following the day on which it was sent. "Business Day" shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario.

17. **ASSIGNMENT OF OPTION BY HYDRO ONE**

Hydro One shall have the right to assign all or any part of its interest in this Option Agreement and any or all rights, privileges and benefits accruing to Hydro One hereunder without the consent of the Owner prior to or on the Closing Date. Upon and to the extent of such assignment, this Option Agreement shall thenceforth be construed as if originally made with such assignee or assignees instead of Hydro One and Hydro One shall, to the extent of such assignment, thereupon be relieved of all liabilities and obligations whatsoever arising out of this Option Agreement.

18. **SURVIVAL OF REPRESENTATIONS**

The parties hereto agree that any representations or covenants contained in this Option Agreement shall not merge on closing, but survive and continue in full force and effect thereafter, but only as to the accuracy of the representation or covenant as at the date of completion of this Option Agreement.

19. **ENTIRE AGREEMENT**

The parties acknowledge that there are no covenants, representations, warranties, agreements or conditions, express or implied, collateral or otherwise, forming part of or in any way affecting or relating to this Option Agreement save as expressly set out in this Option Agreement and that this Option Agreement and all Schedules hereto constitute the entire agreement between the parties and may not be modified except as expressly agreed between the Owner and Hydro One in writing.

20. **SEVERABILITY**

Any provision or provisions of this Option Agreement is declared illegal or unenforceable, it or they shall be considered separate and severable from the Option Agreement and the remaining provisions shall remain in force and be binding upon the parties hereto as though the said provision or provisions had never been included.

21. **GOVERNING LAW**

This Option Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario.

22. **SUCCESSORS AND ASSIGNS**

This Option Agreement shall enure to the benefit of and be binding upon the parties hereto and their respective heirs, attorneys, guardians, estate trustees, executors, trustees, successors and permitted assigns.

23. **EXECUTION AND DELIVERY**

This Option Agreement may be executed in any number of counterparts, each of which is deemed to be an original and all of which taken together constitutes one agreement. To evidence the fact that it has executed this Option Agreement, a party may send a copy of its executed counterpart to all other parties by a delivery method set out in Section 16 herein (the "Transmission") and the signature transmitted by such Transmission is deemed to be its original signature for all purposes.

24. **PLANNING ACT**

This Option Agreement is subject to the express condition that it is to be effective only if the provisions of the *Planning Act, R.S.O. 1990, c. P.13* and amendments thereto are complied with.

25. **FURTHER ASSURANCES**

The Owner covenants and agrees to execute if necessary, at no further cost or condition to Hydro One such other instruments, plans and documents as may reasonably be required by Hydro One to effect the registration of the Easement or notice of this Option Agreement on title to the Lands.

26. **SPOUSAL CONSENT**

The Owner represents that, except to the extent such consent has been obtained, spousal consent to this transaction is not necessary and on closing will not be necessary under the provisions of the *Family Law Act*, R.S.O. 1990, c. F.3.

27. **AGE**

The Owner represents that the Owner is at least 18 years of age.

SCHEDULE "C"
TRANSFER AND GRANT OF EASEMENT

«Owner_1_name_for_letters» & **«Owner_2_name_for_letters»** & **«Owner_3_name_for_letters»** (the "**Transferor**") is the owner in fee simple and in possession of the certain lands legally described as «Legal_Description» (the "**Lands**").

Hydro One Networks Inc. (the "**Transferee**") has erected, or is about to erect, certain Works (as more particularly described in paragraph 1(a) hereof) in, through, under, over, across, along and upon the Lands.

1. The Transferor hereby grants and conveys to the Transferee, its successors and assigns the rights and easement, free from all encumbrances and restrictions, the following unobstructed rights, easements, rights-of-way, covenants, agreements and privileges in perpetuity (the "**Rights**") in, through, under, over, across, along and upon that portion of the Lands of the Transferor described herein as ● and described as Part ● on Reference Plan ● hereto annexed (the "**Strip**"), for the following purposes:

(a) To enter and lay down, install, construct, erect, maintain, open, inspect, add to, enlarge, alter, repair and keep in good condition, move, remove, replace, reinstall, reconstruct, relocate, supplement and operate and maintain at all times in, through, under, over, across, along and upon the Strip an electrical transmission systems and telecommunications systems consisting in both instances of pole structures, steel towers, anchors, guys and braces and all such aboveground or underground lines, wires, cables, telecommunications cables, grounding electrodes, conductors, apparatus, works, accessories, associated material and equipment, and appurtenances pertaining to or required by either such system (all or any of which are herein individually or collectively called the ("Works")) as in the opinion of the Transferee are necessary or convenient thereto for use as required by Transferee in its undertaking from time to time, or a related business venture.

(b) To enter on and selectively cut or prune, and to clear and keep clear, and remove all trees, branches, bush and shrubs and other obstructions and materials in, over or upon the Strip, and without limitation, to cut and remove all leaning or decayed trees located on the Lands whose proximity to the Works renders them liable to fall and come in contact with the Works or which may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(c) To conduct all engineering, legal surveys, and make soil tests, soil compaction and environmental studies and audits in, under, on and over the Strip as the Transferee in its discretion considers requisite.

(d) To erect, install, construct, maintain, repair and keep in good condition, move, remove, replace and use bridges and such gates in all fences which are now or may hereafter be on the Strip as the Transferee may from time to time consider necessary.

(e) Except for fences and permitted paragraph 2(a) installations, to clear the Strip and keep it clear of all buildings, structures, erections, installations, or other obstructions of any nature (hereinafter collectively called the "**obstruction**") whether above or below ground, including removal of any materials and equipment or plants and natural growth, which in the opinion of the Transferee, endanger its Works or any person or property or which may be likely to become a hazard to any Works of the Transferee or to any persons or property or which do or may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(f) To enter on and exit by the Transferor's access routes and to pass and repass at all times in, over, along, upon and across the Strip and so much of the Lands as is reasonably required, for the Transferee, its employees, agents, contractors, subcontractors, workmen and permittees with or without all plant machinery, material, supplies, vehicles and equipment for all purposes necessary or convenient to the exercise and enjoyment of this easement, subject to compensation afterwards for any crop or other physical damage only to the Lands or permitted structures sustained by the Transferor caused by the exercise of this right of entry and passageway.

(g) To remove, relocate and reconstruct the line on or under the Strip subject to payment by the Transferee of additional compensation for any damage caused thereby.

2. The Transferor agrees that:

(a) It will not interfere with any Works established on or in the Strip and shall not, without the Transferee's consent in writing erect or cause to be erected or permit in, under or upon the Strip any obstruction or plant or permit any trees, bush, shrubs, plants or natural growth which does or may interfere with the Rights granted herein. The Transferor agrees it shall not, without the Transferee's consent in writing, change or permit the existing configuration, grade or elevation of the Strip to be changed and the Transferor further agrees that no excavation or opening or work which may disturb or interfere with the existing surface of the Strip shall be done or made unless consent therefore in writing has been obtained from Transferee, provided however, that the Transferor shall not be required to obtain such permission in case of emergency. Notwithstanding the foregoing, in cases where in the reasonable discretion of the Transferee, there is no danger or likelihood of danger to the Works of the Transferee or to any persons or property and the safe or serviceable operation of this easement by the Transferee is not interfered with, the Transferor may at its expense and with the prior written approval of the Transferee, construct and maintain roads, lanes walks, drains, sewers water pipes, oil and gas pipelines, fences (not to exceed 2 metres in height) and service cables on or under the Strip (the "Installation") or any portion thereof; provided that prior to commencing such Installation, the transferor shall give to the Transferee thirty (30) days notice in writing thereof to enable the Transferee to have a representative present to inspect the proposed Installation during the performance of such work, and provided further that Transferor comply with all instructions given by such representative and that all such work shall be done to the reasonable satisfaction of such representative. In the event of any unauthorised interference aforesaid or contravention of this paragraph, or if any authorised interference, obstruction or Installation is not maintained in accordance with the Transferee's instructions or in the Transferee's reasonable opinion, may subsequently interfere with the Rights granted herein, the Transferee may at the Transferor's expense, forthwith remove, relocate, clear or correct the offending interference, obstruction, Installation or contravention complained of from the Strip, without being liable for any damages cause thereby.

(b) Notwithstanding any rule of law or equity, the Works installed by the Transferee shall at all times remain the property of the Transferee, notwithstanding that such Works are or may become annexed or affixed to the Strip and shall at anytime and from time to time be removable in whole or in part by the Transferee.

(c) No other easement or permission will be transferred or granted and no encumbrances will be created over or in respect to the Strip, prior to the registration of a Transfer of this grant of Rights.

(d) The Transferor will execute such further assurances of the Rights in respect of this grant of easement as may be requisite.

(e) The Rights hereby granted:

(i) shall be of the same force and effect to all intents and purposes as a covenant running with the Strip.

(ii) is declared hereby to be appurtenant to and for the benefit of the Works and undertaking of the Transferee described in paragraph 1(a).

3. Provided that the lands are used for agricultural purposes, the Transferee hereby releases and forever discharges the Transferor from and against any and all action, causes of action, costs,

claims, demands, expenses and liability for upon or by reason of any damage to the Works (collectively the "Claims") which may arise from, be sustained, suffered or incurred in consequence of the Transferor using the lands for agricultural purposes save and except for any Claims resulting from or arising out of the Transferor's negligence or willful misconduct.

4. The Transferor agrees that the Transferee may, at the Transferee's sole discretion, obtain at the Transferee's sole cost and expense all necessary postponements and subordinations (in registrable form) from all current and future prior encumbrancers, postponing their respective rights, title and interests to the Transfer of Easement herein so as to place such Rights and easement in first priority on title to the Lands.

5. There are no representations, covenants, agreements, warranties and conditions in any way relating to the subject matter of this grant of Rights whether expressed or implied collateral or otherwise except those set forth herein.

6. No waiver of a breach or any of the covenants of this grant of Rights shall be construed to be a waiver of any succeeding breach of the same or any other covenant.

7. The burden and benefit of this transfer of Rights shall run with the Strip and the Works and undertaking of the Transferee and shall extend to, be binding upon and enure to the benefit of the parties hereto and their respective heirs, executors, administrators, successors and assigns.

SCHEDULE "D"
ACKNOWLEDGEMENT AND DIRECTION

TO:	Hydro One Networks Inc. ("**Hydro One**") and its solicitors, Barriston LLP
AND TO:	Any and all designees of the above
RE:	Option Agreement dated __________________, 20____, (the "Option Agreement) and the Transfer and Grant of Easement in substantially the form attached **[as Schedule "C" to the Option Agreement or hereto]** (the "Easement Agreement")

This will confirm that:

- Hydro One and the Owner have reviewed the information set out in the Option Agreement and the draft document(s) attached to the Option Agreement, and that this information is accurate;
- You are authorized and directed to sign and register electronically on behalf of the undersigned the Option Agreement and the Easement Agreement as well as any other document(s) required to complete the transaction described above;
- You are authorized to amend the Option Agreement and the Easement Agreement as may be required to effect registration of such document including the insertion of a registerable legal description to describe the lands subject to the easement being granted pursuant to the Easement Agreement in the event one is not available at the time of execution of the Option Agreement; provided such amendments are non-material to the terms of the Option Agreement and the Easement Agreement and do not expand the description of the Easement Lands as described and/or illustrated in the Option Agreement in any material manner;
- The effect of the electronic documents described in this Acknowledgement and Direction has been fully explained to the Owner and Hydro One, and the Owner and Hydro One understand that each are parties to and bound by the terms and provisions of these electronic document(s) to the same extent as if each had signed these documents;
- You are directed to insert the names set forth in the signatory section of the Option Agreement as persons authorized (or other authorized signing officers of Hydro One) to act on behalf of Hydro One and the Owner, as applicable;
- The Owner acknowledges that Barriston LLP has not met with them nor been engaged by them, is not entering into a solicitor-client relationship with them and is not representing them solely or jointly with Hydro One for the purposes of the preparation, negotiation, completion or registration of the Option Agreement or the Easement Agreement. Barriston LLP will act in a limited capacity as agent for the undersigned for the purposes of registering the Option Agreement and the Easement Agreement; and
- Hydro One and the Owner are in fact the parties named in the electronic documents described in this Acknowledgement and Direction and each has not misrepresented the identity of same to you.

Dated _________________, 20__.

WITNESS:	**OWNER:**
______________________________	______________________________ l/s
Name: «Real_Estate_Representative»	Name: **«Owner_1_name_for_letters»**
Address:	
______________________________	______________________________ l/s
Name: «Real_Estate_Representative»	Name: **«Owner_2_name_for_letters»**
Address:	______________________________
______________________________	______________________________ l/s
Name: «Real_Estate_Representative»	Name: **«Owner_3_name_for_letters»**
Address:	
WITNESS:	The spouse of the Owner hereby consents to this

Acknowledgement and Direction

SPOUSE OF OWNER:

______________________________	______________________________ l/s
Name: Real Estate Representative Address:	Name: **Property Owner Spouse Name**

«OWNER_1_NAME_FOR_LETTERS»

Per: ______________________________

Name:

Title:

We/I have authority to bind the Corporation

COMPENSATION AND INCENTIVE AGREEMENT – EASEMENT

COMPENSATION AND INCENTIVE AGREEMENT - EASEMENT

THIS COMPENSATION AND INCENTIVE AGREEMENT made as of the __________day of __________________ , 20___ (the "**Agreement Date**").

B E T W E E N:

«OWNER_1_NAME_FOR_LETTERS» & «OWNER_2_NAME_FOR_LETTERS» & «OWNER_3_NAME_FOR_LETTERS»

(hereinafter collectively called the "**Owner**")

OF THE FIRST PART

- and -

HYDRO ONE NETWORKS INC.

(hereinafter called "**Hydro One**")

OF THE SECOND PART

- and -

SPOUSE NAME

(hereinafter collectively called the "**Spouse**") This section is only filled out if the spouse is not on title

OF THE THIRD PART

RECITALS:

A. The Owner is the owner of the lands and premises described in Schedule "A" attached hereto (the "**Lands**").

B. Hydro One desires to purchase a right of way and easement, in, on, over, under, across and through that portion of the Lands, as more particularly described in an Option Agreement between the parties hereto and having a date the same as this Compensation and Incentive Agreement (the "**Option Agreement**") (the "**Easement Lands**"), upon the terms and conditions set out in the Option Agreement (the "**Easement**").

C. Hydro One has offered to pay the Option Payment to the Owner upon execution of the Option Agreement and upon closing to purchase the Easement from the Owner for the Purchase Price.

D. Hydro One has offered, on the terms and conditions set out herein, to compensate the Owner for injurious affection damages, if applicable (the "**IA Compensation**") in respect of that portion of the Lands which are not part of the Easement Lands. Such injurious affection damages are calculated as shown on the calculation sheet attached hereto as Schedule "B" (the "**Calculation Sheet**").

E. To achieve a timely resolution of its land acquisition arrangements, Hydro One has also offered to pay certain incentives to the Owner on the terms and conditions set out in this Compensation and Incentive Agreement and as shown on the Calculation Sheet.

F. Any capitalized terms not defined in this Compensation and Incentive Agreement shall have the meaning ascribed to them in the Option Agreement.

NOW THEREFORE, the parties agree as follows:

1. **VALUATION**

(a) Hydro One has retained an external, independent AACI designated appraiser to determine the fair market value of the Easement Lands and any applicable amount of IA Compensation, if any, as of XXXXDate and to prepare a report in respect thereof (the "**HONI Appraisal**"). The Owner acknowledges receiving a copy of the HONI Appraisal, and agrees to accept the amounts set out in the HONI Appraisal as a fair evaluation of the market value of the Owner's fee simple interest in the Easement Lands as of the date of the HONI Appraisal.

(b) In recognition of a dynamic real estate market and that the effective date of Hydro One's appraised values in the HONI Appraisal are only relevant for a limited period of time, Hydro One shall provide a market value top-up where the passage of time between the HONI Appraisal Date and the date Hydro One exercises the Option Agreement is greater than one (1) year and such passage of time warrants such a top-up (the "**Top-Up**").

The amount of the Top-Up, if any, shall be the difference between (i) the market value set out in the HONI Appraisal, and (ii) the market value as of the date Hydro One exercises the Option Agreement (provided such date is at least one (1) year after the HONI Appraisal Date). The Top-Up shall only be applicable to the extent that the market value as of the date the Option Agreement is exercised is greater than the amount in the HONI Appraisal. Such adjustment shall be made for time only (change in market conditions) and based on an independent land rate study considering this singular factor. The land rate study will be prepared by an independent third party appraiser with an Accredited Appraiser Canadian Institute designation from the Appraisal Institute of Canada.

The Top-Up amounts will be paid by Hydro One to the Owner by adding the applicable amounts to the Purchase Price, Premium Above Fair Market Value, and the IA Compensation, if applicable.

(c) The actual area of the Easement Lands will be confirmed by a survey to be prepared by Hydro One and in the event the surveyed area of the Easement Lands is greater than as provided for in the Calculation Sheet, the payments set out in section 2 herein will be adjusted accordingly.

2. **INCENTIVE PAYMENTS**

(a) Upon execution of the Option Agreement and this Compensation and Incentive Agreement by all parties thereto, Hydro One shall pay to or to the order of the Owner the Option Payment in the amount of **XXXXX ($XXXXX)** as set out on the Calculation Sheet.

(b) On the Closing Date, Hydro One shall make a further incentive payment to or to the order of the Owner in the amount of **XXXXX ($XX)**, (the "**Acceptance of the Hydro One Offer**") as set out on the Calculation Sheet.

(c) On the Closing Date, Hydro One shall make a further incentive payment to or to the order of the Owner in the amount of **XXXXX ($XX), (the "Premium Above Fair Market Value")** such amount being equal to XX% of the appraised fair market value of the Owner's fee simple interest in the Easement Lands as set out on the Calculation Sheet.

3. **WAIVER**

The Owner waives the right to be reimbursed by Hydro One for the reasonable costs the Owner incurs for a third party independent appraisal report and/or legal review of the HONI Appraisal, the Option Agreement and this Compensation and Incentive Agreement, up to the amount of Seven Thousand Five Hundred Dollars ($7,500.00) and hereby accepts the Acceptance of the Hydro One Offer as defined in 2(b) above.

4. IA COMPENSATION

Hydro One agrees to pay to or to the order of the Owner on the Closing Date the IA Compensation, if applicable, in the amount of **XXXXX ($XX)** as set out on the Calculation Sheet.

5. CONVEYANCING

Hydro One agrees to reimburse the Owner for reasonably incurred legal fees, if any, associated with the review of applicable conveyancing documents.

6. TENANTS

The Owner agrees to indemnify and save harmless Hydro One from all actions, suits, costs, losses, charges, demands, claims and expenses for and in respect of any claims any person having a possessory interest in the Easement Lands.

7. NOTICES

Notices to be given to either party shall be in writing, and will be sent via electronic mail ("email"), personally delivered or sent by registered mail (except during a postal disruption or threatened postal disruption), telegram, electronic facsimile or other similar means of prepaid recorded communication to the applicable address set forth below (or to such other address as such party may from time to time designate in such manner):

HYDRO ONE:

Hydro One Networks Inc.
Facilities and Real Estate
P.O. Box 4300
Markham, Ontario L2R 5Z5

185 Clegg Road
Markham, Ontario L3G 1B7

Attention:
Fax: (905) 946-6242

with a copy to its solicitors,

Barriston LLP
90 Mulcaster Street
Barrie, ON L4M 4Y5

Attention: Jim McIntosh
Fax: 705-721-4025

OWNER:

«Owner_1_name_for_letters» &
«Owner_2_name_for_letters» &
«Owner_3_name_for_letters»
«STREET_NUM» «STREET_NAME1»
«MUNICIPALITY», «PROVINCE»
«POSTAL_CODE»

«SAP_Phone_Number»
«SAP_email_address»

with a copy to their solicitors,

Solicitors Name
Solicitors Address 1
Solicitors Address 2
Solicitors Address 3

Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5th) business day following the date on which it was sent. Any notice sent by telegram, email, electronic facsimile or other similar means of prepaid recorded communication shall be deemed to have been validly and effectively given on the Business Day next following the day on which it was sent. "Business Day" shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario.

8. ASSIGNMENT OF AGREEMENT BY OWNER

The Owner shall not assign all or any part of its interest in this Compensation and Incentive Agreement or any of the rights, privileges and benefits accruing to the Owner hereunder without the consent of the Hydro One, which consent may not be unreasonably withheld or delayed. Upon and to the extent of such assignment, this Compensation and Incentive Agreement shall thenceforth be construed as if originally made with such assignee or assignees instead of the

Owner and the Owner shall, to the extent of such assignment, thereupon be relieved of all liabilities and obligations whatsoever arising out of this Compensation and Incentive Agreement.

The Owner and, if applicable, the Spouse, each covenant and agree that if they transfer, assign, charge, lease or otherwise dispose of all or any part of their interest in the Lands (collectively, a "**Transfer**") they will obtain an agreement from such Transferee assuming and agreeing to be bound by all of the terms of this Compensation and Incentive Agreement as if the Transferee had been an original signatory to this Compensation and Incentive Agreement.

9. NOTICE OF AGREEMENT

Hydro One may, in its sole discretion and at its sole expense register this Compensation and Incentive Agreement or notice thereof on title to the Lands.

10. NO MERGER

The parties hereto agree that any representations or covenants contained in this Compensation and Incentive Agreement shall not merge on closing, but survive and continue in full force and effect thereafter, but only as to the accuracy of the representation or covenant as at the date of completion of this Compensation and Incentive Agreement.

11. ENTIRE AGREEMENT

The parties hereto acknowledge that there are no covenants, representations, warranties, agreements or conditions, express or implied, collateral or otherwise, forming part of or in any way affecting or relating to this Compensation and Incentive Agreement save as expressly set out in this Compensation and Incentive Agreement and that this Compensation and Incentive Agreement and all Schedules hereto constitute the entire agreement between the parties and may not be modified except as expressly agreed between the parties in writing.

12. SEVERABILITY

Any provision or provisions of this Compensation and Incentive Agreement is declared illegal or unenforceable, it or they shall be considered separate and severable from this Compensation and Incentive Agreement and the remaining provisions shall remain in force and be binding upon the parties hereto as though the said provision or provisions had never been included.

13. GOVERNING LAW

This Compensation and Incentive Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario.

14. SPOUSAL CONSENT

The Owner represents that, except to the extent such consent has been obtained, spousal consent to this transaction is not necessary under the provision of the *Family Law Act*, R.S.O. 1990, c. F.3.

15. SUCCESSORS AND ASSIGNS

This Compensation and Incentive Agreement shall enure to the benefit of and be binding upon the parties hereto and their respective heirs, attorneys, guardians, estate trustees, executors, trustees, successors and permitted assigns.

16. EXECUTION AND DELIVERY

This Compensation and Incentive Agreement may be executed in any number of counterparts, each of which is deemed to be an original and all of which taken together constitutes one agreement. To evidence the fact that it has executed this Compensation and Incentive Agreement, a party may send a copy of its executed counterpart to all other parties by a delivery method set out in Section 7 herein (the "**Transmission**") and the signature transmitted by such Transmission is deemed to be its original signature for all purposes.

17. FURTHER ASSURANCES

The parties hereto agree to do, make and execute, if necessary, at no further cost or condition to the other except payment of reasonable out-of-pocket costs, such other instruments, plans, documents, acts, matters and things and take such further action as may reasonably be required by the other party in order to effectively carry out the true intent of this Compensation and Incentive Agreement.

18. <u>AGE</u>

The Owner represents that the Owner is at least 18 years of age.

IN WITNESS WHEREOF the parties hereto have duly executed this Compensation and Incentive Agreement as of the Agreement Date.

WITNESS:	**OWNER:**
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_1_name_for_letters»**
Address:	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_2_name_for_letters»**
Address:	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_3_name_for_letters»**
Address:	
WITNESS:	The spouse of the Owner hereby consents to this Compensation and Incentive Agreement
	SPOUSE OF OWNER:
	l/s
Name: «Real_Estate_Representative»	Name: **Property Owner Spouse Name**
Address:	

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________

Name:
Title:

I have authority to bind the Corporation

SCHEDULE “A”

LANDS

«LEGAL_DESCRIPTION»

SCHEDULE “B”

CALCULATION SHEET

OPTION TO PURCHASE A LIMITED INTEREST – FEE SIMPLE

OPTION AGREEMENT - FEE SIMPLE CORRIDOR

THIS OPTION AGREEMENT made as of the __________ day of _________________, 202__ (the "**Agreement Date**").

B E T W E E N:

«OWNER_1_NAME_FOR_LETTERS» & «OWNER_2_NAME_FOR_LETTERS» & «OWNER_3_NAME_FOR_LETTERS»

(hereinafter collectively called the "**Owner**")

OF THE FIRST PART

- and -

HYDRO ONE NETWORKS INC.

(hereinafter called "**Hydro One**")

OF THE SECOND PART

- and -

SPOUSE NAME

(hereinafter collectively called the "**Spouse**") This section is only filled if the spouse is not on title

OF THE THIRD PART

RECITALS:

A. The Owner is the owner of the lands and premises described in Schedule "A" attached hereto (the "**Lands**");

B. The Owner has agreed to grant to Hydro One for the consideration and on the terms and conditions set out herein and attached hereto as Schedule "B" (the "**Standard Terms and Conditions**") an option to purchase that portion of the Lands described on Schedule "A-1" attached hereto (the "**Corridor Lands**") on the terms and conditions set out herein and attached hereto as Schedule "C" (the **"Agreement of Purchase and Sale"**).

C. Hydro One has entered into an agreement with the Owner having a date the same as this Option Agreement (the "Compensation and Incentive Agreement").

NOW THEREFORE, the parties hereby agree as follows:

1. **GRANT OF OPTION**

In consideration of the sum of **XXX ($XXX)** of lawful money of Canada paid by Hydro One to the Owner, the receipt and sufficiency of which is hereby acknowledged by the Owner, (the **"Option Payment"**) the Owner hereby grants to Hydro One the an irrevocable option (the "**Option**"), to purchase the Owner's fee simple interest in the Corridor Lands upon and subject to the terms and conditions set out herein, the Standard Terms and Conditions and the Schedules hereto.

2. **PURCHASE PRICE**

In accordance with the terms and conditions set out herein, the Standard Terms and Conditions and the Schedules hereto, Hydro One agrees to pay to or to the order of the Owner the amount of **XXXX Dollars ($ ●)** for the Corridor Lands (the "**Purchase Price**") on the Closing Date.

IN WITNESS WHEREOF the parties hereto have duly executed this Option Agreement as of the Agreement Date.

WITNESS:	**OWNER:**
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_1_name_for_letters»**
Address:	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_2_name_for_letters»**
Address:	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_3_name_for_letters»**
Address:	
WITNESS:	The spouse of the Owner hereby consents to this Agreement
	SPOUSE OF OWNER:
	l/s
Name: Real Estate Representative	Name: **Property Owner Spouse Name**
Address:	

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ________________________

Name:
Title:

I have authority to bind the Corporation

File: «FileNo»

SCHEDULE "A"
LEGAL DESCRIPTION

«LEGAL_DESCRIPTION»

File: «FileNo»

SCHEDULE "A-1"
CORRIDOR LANDS

Legal description to be determined by deposited Reference Plan; Corridor Lands shown outlined in green.

****NOTE – Sketch shall be replaced by Corridor Lands description once applicable Reference Plan is deposited.**

Screenshot of ortho map with tower placements here

SCHEDULE "B"
STANDARD TERMS AND CONDITIONS

1. **EXERCISE OF OPTION**

The Option shall be open for exercise at any time from the Agreement Date until the 2nd anniversary of the Agreement Date, as same may have been extended in accordance with the terms hereof, (the "**Option Term**"), by providing written notice to the Owner (the "**Exercise Notice**"), after which time, subject to Section 2, this Option Agreement shall be null and void and no longer binding upon either of the parties. If the Option is exercised within the Option Term, then this Option Agreement shall become a binding agreement for the purchase and sale of the Corridor Lands and this Option Agreement shall be completed on the terms set out herein.

2. **EXTENSION OF OPTION TERM**

At any time during the Option Term, Hydro One may, by written notice delivered to the Owner prior to the expiration of the Option Term, as same may have been extended, extend the Option Term with respect to the Lands for one (1) additional period of one (1) year, provided that upon such election, Hydro One pays to the Owner the amount of $XXXXX in consideration for the extension of the Option Term.

3. **PURCHASE PRICE**

Hydro One shall pay the Purchase Price to or to the order of the Owner by way of a single payment by uncertified cheque or electronic funds transfer on the Closing Date (as hereinafter defined).

The Owner acknowledges receipt of an appraisal report commissioned by Hydro One and, prepared by an external, independent appraiser with the Accredited Appraiser Canadian Institute ("AACI") designation, (the "**HONI Appraisal**").

4. **CLOSING**

The transaction of purchase and sale contemplated by this Option Agreement and the Agreement of Purchase and Sale shall, subject to resolution of any title issues identified pursuant to Article 5 of the Agreement of Purchase and Sale, be completed on the date that is ninety (90) days after Hydro One delivers the Exercise Notice to the Owner or on such earlier date as Hydro One, through its solicitors, may elect (the **"Closing Date"**). If the Closing Date is a date on which the Land Registry Office (the "**Land Registry Office**") in which the Lands are registered is closed, the Closing Date shall be on the next following day when such Land Registry Office is open. In the event that there is a delay in the completion of the transaction beyond the Closing Date as established by Hydro One upon delivery of the Exercise Notice that arises through no fault of Hydro One, then Hydro One shall not be responsible for any resulting delay in the Closing Date.

5. **AGREEMENT OF PURCHASE AND SALE**

The Owner and, if applicable, the Spouse, acknowledge and agree that execution of this Option Agreement shall constitute execution of the Agreement of Purchase and Sale attached as Schedule "C" to this Option Agreement.

6. **RIGHT TO TRANSFER AND TITLE**

The Owner covenants and agrees with Hydro One that it has good and marketable title to the Corridor Lands and has the full and exclusive power to convey the fee simple interest in the Corridor Lands to Hydro One free and clear of any financial encumbrances, and that Hydro One will quietly possess and enjoy the Corridor Lands.

7. **INSPECTION PERIOD AND EARLY ACCESS PERIOD**

(a) The Owner agrees and consents to Hydro One, its respective officers, employees, agents, contractors, sub-contractors, surveyors, workers and permittees or any of them entering on, exiting and passing and repassing in, on, over, along, upon, across, through and under the Corridor Lands and so much of the Lands as may be reasonably necessary at all reasonable times from the Agreement Date until the later of the expiration of the Option Term (as same may be extended) and the Closing Date, with or without all plant, machinery, material, supplies, vehicles, and equipment, for all purposes necessary or convenient to conduct such inspections, tests, audits, reports as Hydro One sees fit in connection with the acquisition, exercise or enjoyment of the Corridor Lands. Hydro One shall restore the Lands to their prior condition so far as reasonably possible following such inspections, tests, audits and reports.

(b) The Owner agrees and consents to Hydro One, its respective officers, employees, agents, contractors, sub-contractors, surveyors, workers and permittees or any of them entering on, exiting and passing and repassing in, on, over, along, upon, across, through and under the Corridor Lands and so much of the Lands as may be reasonably necessary at all reasonable times from date Hydro One delivers the Exercise Notice to commence construction activities on the Corridor Lands. Hydro One shall restore the Lands to their prior condition so far as reasonably possible in the event that the purchase transaction contemplated by this Option Agreement is not completed as contemplated herein.

8. <u>SURVEY/REFERENCE PLAN</u>

Hydro One agrees to obtain and register, at its sole expense, any new Reference Plan with respect to the Corridor Lands that may be required by Hydro One for completion of this Option Agreement.

9. <u>INCOME TAX ACT</u>

The Owner represents and warrants and covenants that the Owner is not now and on Closing will not be a non-resident of Canada within the meaning of the *Income Tax Act (Canada).*

10. <u>HARMONIZED SALES TAX</u>

The Owner and Hydro One acknowledge and agree that the transfer of the fee simple of the Corridor Lands which is proposed under this Option Agreement constitutes a purchase and sale transaction of an interest in real property, and therefore, in conformance with subsections 221(2) and 228(4) of the *Excise Tax Act* R.S.C. 1985, c E-15, as amended ("the Act"), Hydro One shall report and pay to the Receiver General for Canada the Harmonized Sales Tax ("HST") applicable to the purchase and sale of the Corridor Lands. For the purposes of this section 11, Hydro One shall warrants that it is an HST registrant in good standing under the Act, that its HST registration number is 870865821RT0001, and that it is acquiring the Corridor Lands for use primarily in the course of its commercial activities.

11. <u>NOTICE OF OPTION</u>

Hydro One may, in its sole discretion and at its sole expense register this Option Agreement or notice thereof on title to the Lands.

12. <u>NO OTHER RIGHTS</u>

The Owner covenants and agrees with Hydro One that the Owner shall not grant, create or transfer any easement, right, covenant, restriction, privilege, permission, or other agreement in, through, under, over or in respect of the Corridor Lands prior to the registration of the Closing of the transaction contemplated herein without the prior written consent of Hydro One.

13. <u>PRIOR ENCUMBRANCES</u>

The Owner hereby grants Hydro One permission, should Hydro One elect in its sole discretion, to approach any encumbrancer having an interest in the Corridor Lands in priority to the Option Agreement and to obtain (in registrable form) and register all necessary consents, postponements or subordinations from all current and future encumbrancers having an interest in the Corridor Lands in priority this Option Agreement consenting, postponing or subordinating such encumbrance and their respective rights, title and interest to the Corridor Lands and this Option Agreement or to place the this Option Agreement in first priority on title to the Corridor Lands.

14. <u>TIME OF ESSENCE</u>

Time shall in all respects be of the essence hereof; provided, however, that the time for doing or completing any matter provided for herein may be extended or abridged by an agreement in writing between the parties or their respective counsel.

15. NOTICES

Notices to be given to either party shall be in writing, and will be sent via electronic mail ("email"), personally delivered or sent by registered mail (except during a postal disruption or threatened postal disruption), telegram, electronic facsimile or other similar means of prepaid recorded communication to the applicable address set forth below (or to such other address as such party may from time to time designate in such manner):

HYDRO ONE:

Hydro One Networks Inc.
Facilities and Real Estate
P.O. Box 4300
Markham, Ontario
L2R 5Z5

185 Clegg Road
Markham, Ontario
L3G 1B7

Attention:
Fax: (905) 946-6242

with a copy to its solicitors,

Barriston LLP
90 Mulcaster Street
Barrie, ON L4M 4Y5

Attention: Jim McIntosh
Fax: (705)-721-4025

OWNER:

«Owner_1_name_for_letters»
«Owner_2_name_for_letters»
«Owner_3_name_for_letters»
«STREET_NUM» «STREET_NAME1»
«MUNICIPALITY», «PROVINCE»
«POSTAL_CODE»

«SAP_Phone_Number»
«SAP_email_address»

with a copy to their solicitors,

Solicitors Name
Solicitors Address 1
Solicitors Address 2
Solicitors Address 3

Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5^{th}) Business Day following the date on which it was sent. Any notice sent by email, telegram, electronic facsimile or other similar means of prepaid recorded communication shall be deemed to have been validly and effectively given on the Business Day next following the day on which it was sent. "Business Day" shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario.

16. ASSIGNMENT OF OPTION BY HYDRO ONE

Hydro One shall have the right to assign all or any part of its interest in this Option Agreement and any or all rights, privileges and benefits accruing to Hydro One hereunder without the consent of the Owner prior to or on the Closing Date. Upon and to the extent of such assignment, this Option Agreement shall thenceforth be construed as if originally made with such assignee or assignees instead of Hydro One and Hydro One shall, to the extent of such assignment, thereupon be relieved of all liabilities and obligations whatsoever arising out of this Option Agreement.

17. SURVIVAL OF REPRESENTATIONS

The parties hereto agree that any representations or covenants contained in this Option Agreement shall not merge on closing, but survive and continue in full force and effect thereafter, but only as to the accuracy of the representation or covenant as at the date of completion of this Option Agreement.

18. ENTIRE AGREEMENT

The parties acknowledge that there are no covenants, representations, warranties, agreements or conditions, express or implied, collateral or otherwise, forming part of or in any way affecting or relating to this Option Agreement save as expressly set out in this Option Agreement and that this Option Agreement and all Schedules hereto constitute the entire agreement between the parties and may not be modified except as expressly agreed between the Owner and Hydro One in writing.

19. SEVERABILITY

Any provision or provisions of this Option Agreement is declared illegal or unenforceable, it or they shall be considered separate and severable from the Option Agreement and the remaining provisions shall remain in force and be binding upon the parties hereto as though the said provision or provisions had never been included.

20. GOVERNING LAW

This Option Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario.

21. SUCCESSORS AND ASSIGNS

This Option Agreement shall enure to the benefit of and be binding upon the parties hereto and their respective heirs, attorneys, guardians, estate trustees, executors, trustees, successors and permitted assigns.

22. EXECUTION AND DELIVERY

This Option Agreement may be executed in any number of counterparts, each of which is deemed to be an original and all of which taken together constitutes one agreement. To evidence the fact that it has executed this Option Agreement, a party may send a copy of its executed counterpart to all other parties by a delivery method set out in Section 15 herein (the "Transmission") and the signature transmitted by such Transmission is deemed to be its original signature for all purposes.

23. PLANNING ACT

This Option Agreement is subject to the express condition that it is to be effective only if the provisions of the *Planning Act*, R.S.O. 1990, c. P.13and amendments thereto are complied with.

24. FURTHER ASSURANCES

The Owner covenants and agrees to execute if necessary, at no further cost or condition to Hydro One such other instruments, plans and documents as may reasonably be required by Hydro One to effect the registration of the transfer of the Corridor Lands or notice of this Option Agreement on title to the Lands.

25. SPOUSAL CONSENT

The Owner represents that, except to the extent such consent has been obtained, spousal consent to this transaction is not necessary and on closing will not be necessary under the provisions of the *Family Law Act*, R.S.O. 1990, c. F.3.

26. AGE

The Owner represents that the Owner is at least 18 years of age.

SCHEDULE "C"
AGREEMENT OF PURCHASE AND SALE

THIS AGREEMENT made as of the ______ day of ____________ , 20____ (the "**Agreement Date**").

B E T W E E N:

«OWNER_1_NAME_FOR_LETTERS» & «OWNER_2_NAME_FOR_LETTERS» & «OWNER_3_NAME_FOR_LETTERS»

(hereinafter collectively called the "**Owner**")

OF THE FIRST PART

- and -

HYDRO ONE NETWORKS INC.

(hereinafter called "**Hydro One**")

OF THE SECOND PART

- and -

SPOUSE NAME

(hereinafter collectively called the "**Spouse**") This section is only filled if the spouse is not on title

OF THE THIRD PART

WITNESSETH THAT in consideration of the mutual covenants, agreements and payments herein provided, the parties hereto covenant and agree as follows:

ARTICLE 1
OFFER

1.1 The Vendor, being the owner of the lands and premises more particularly described in Schedule "A" (the "**Lands**") hereby agrees to sell to the Purchaser and the Purchaser agrees to purchase from the Vendor, on the terms and conditions set out in this Agreement, a portion of the Lands more particularly described on Schedule "A-1" attached hereto (the "**Property**") upon and subject to the terms and conditions hereinafter set forth.

1.2 The Vendor acknowledges and understands that upon execution of this Agreement by the Vendor and the Purchaser there shall be a binding agreement of Purchase and Sale between the Purchaser and the Vendor.

1.3 Included in the Purchase Price is the purchase of all of the Vendor's interest in all fixtures, improvements, and appurtenances located on the Property except those listed below which are expressly excluded:

NIL

ARTICLE 2
PURCHASE PRICE

2.1 (a) The total compensation to be paid by the Purchaser to the Vendor for the Property shall be the sum of **«TotalCompensationRounded»** Canadian Dollars, (the "**Total Compensation**"), subject to usual adjustments, if any, payable on Closing by uncertified cheque or electronic funds transfer on the Closing (as hereinafter defined).

(b) The Total Compensation is comprised as follows:

(i)	Purchase Price of the Property	**$XXXX**
(ii)	IA Compensation	**$XXXX**
(iii)	Option Payment	**$XXXX**
(iv)	Acceptance of the Hydro One Offer	**$XXXX**
(v)	Premium Above Fair Market Value	**$XXXX**
(vi)	Allowance Payment	**$XXXX**
(vii)	Access Agreement	**$XXXX**
TOTAL COMPENSATION		**$XXXX.00**

2.2 The Vendor acknowledges receipt of an appraisal report and update, if any, prepared by an external, independent AACI accredited appraiser commissioned by the Purchaser.

2.3 The Purchaser agrees to obtain and register, at its sole expense, any new Reference Plan with respect to the Property that may be required by the Purchaser for completion of this Agreement of Purchase and Sale.

2.4 The calculation of the Total Compensation is shown on the calculation sheet attached hereto as Schedule "C" (the **"Calculation Sheet"**).

ARTICLE 3
CLOSING

3.1 The transaction of purchase and sale contemplated by this Agreement of Purchase and Sale shall, subject to resolution of any title issues identified pursuant to Article 5 of the Agreement of Purchase and Sale, be completed on the date that is ninety (90) days after Hydro One delivers the Exercise Notice to the Owner or on such earlier date as Hydro One, through its solicitors, may elect (the **"Closing Date"**). If the Closing Date is a date on which the Land Registry Office (the "**Land Registry Office**") in which the Lands are registered is closed, the Closing Date shall be on the next following day when such Land Registry Office is open. In the event that there is a delay in the completion of the transaction beyond the Closing Date as established by Hydro One upon delivery of the Exercise Notice that arises through no fault of Hydro One, then Hydro One shall not be responsible for any resulting delay in the Closing Date.

3.2 On Closing,

(a) Vacant possession of the Property shall be given to the Purchaser;

(b) The Purchaser shall pay the Total Compensation to the Vendor in accordance with section 2.1 of this Agreement;

(c) If applicable, rents, realty taxes, local improvement charges, water and unmetered utility charges and the cost of fuel as applicable shall be apportioned and allowed to the date of completion (the day itself to be apportioned to the Purchaser);

(d) In conformance with subsections 221(2) and 228(4) of the *Excise Tax Act* R.S.C. 1985, c E-15, as amended ("the Act"), Purchaser shall report and pay to the Receiver General, the Harmonized Sales Tax ("HST") applicable to the purchase and sale of the Property. For the purposes of this clause 3.2(b), the Purchaser warrants that it is an HST registrant in good standing under the Act, that its HST registration number is 870865821RT0001, and that it is acquiring the Property for use primarily in the course of its commercial activities.

ARTICLE 4
INSPECTION PERIOD

4.1 The Purchaser shall be allowed thirty (30) days from the date of this Agreement (the **"Inspection Period"**) to satisfy itself with respect to all matters respecting the Property including its present state of repair and condition and any structures thereon, all encumbrances and all regulations and by-laws governing the Property and the Vendor grants to the Purchaser the right to enter upon the Property and to conduct such inspections, surveys and tests as the Purchaser, acting reasonably, deems necessary in this regard, provided the Purchaser takes all reasonable care in the conduct of such inspections, surveys and tests and restores the Property to its prior condition so far as reasonably possible following such inspections and tests. The Vendor assumes no responsibility for and the Purchaser shall indemnify and save harmless the Vendor from and against all claims, demands, costs, damages, expenses and liabilities whatsoever arising out of its presence on the Property or of its activities on or in connection with the Property during the Inspection Period.

4.2 If for any reason, the Purchaser, acting reasonably, is not satisfied with respect to such matters arising from its activities in Section 4.1 herein, it may deliver a notice (the **"Notice of Termination"**) to the Vendor prior to the expiry of the Inspection Period indicating that it is not satisfied with respect to such matters and desires to terminate this Agreement and release the Vendor from any further obligations. Upon delivery by the Purchaser of a Notice of Termination to the Vendor, and this Agreement shall be at an end and neither Party shall have any further obligation to the other respecting the Agreement.

ARTICLE 5
TITLE

5.1 The Purchaser shall be allowed thirty (30) days from the date of this Agreement to investigate title to the Property at its own expense (the "**Title Search Period**"), to satisfy itself that there are no outstanding encumbrances, or liens save and except those listed in Schedule "B" attached hereto and until the earlier of: (i) thirty (30) days from the later of the last date of the title search period or the date or which the conditions in this Agreement are fulfilled or otherwise waived or; (ii) five (5) days prior to completion, to satisfy itself that there are no outstanding work orders or deficiency notices affecting the property. Vendor hereby consents to the Municipality or other governmental agencies releasing to the Purchaser details of all outstanding work orders affecting the Property and the Vendor agrees to execute and deliver such further authorizations in this regard as Purchaser may reasonably require.

5.2 Provided that the title to the Property is good and free from all registered restrictions, charges, liens and encumbrances except those listed in Schedule "B" attached hereto, if within the Title Search Period, any valid objection to title is made by the Purchaser in writing to the Vendor together with documentary verification thereof, and which the Vendor shall be unwilling or unable to remove and which the Purchaser will not waive, this Agreement, notwithstanding any intermediate acts or negotiations in respect of such objections, shall be at an end and the Vendor shall not be liable for any costs or damages and the Vendor and the Purchaser shall be released from all obligations hereunder, and the Vendor shall also be released from all obligations under this Agreement, save and except those covenants of the Purchaser expressly stated to survive Closing or other termination of this Agreement. Save as to any valid objection to title made in accordance with this Agreement and within the Title Search Period, and except for any objection going to the root of title, Purchaser shall be conclusively deemed to have accepted Vendor's title to the Property.

5.3 The Vendor and Purchaser agree that there is no condition, express, or implied, representation or warranty of any kind that the future intended use of the Property by the Purchaser is or will be lawful except as may be specifically stipulated elsewhere in this Agreement.

5.4 The Vendor agrees to provide to the Purchaser any existing survey of the Property, within Fifteen (15) days from the date of this Agreement.

ARTICLE 6
PURCHASER'S INVESTIGATION RESULTS

6.1 Purchaser shall, at its own cost, forthwith make such investigation as the Purchaser deems appropriate of the Property and Vendor's title as provided for in this Agreement and shall notify the Vendor of any objection to title, together with a complete copy of any documents and other material information related thereto prior to the expiry of the Title Search Period.

ARTICLE 7
INSURANCE

7.1 The Vendor covenants and agrees that the Property and all structures or fixtures being purchased are insured, and that such insurance will remain in force until closing. The Property and all structures or fixtures being purchased shall be and remain at the risk of the Vendor until Closing.

7.2 Pending completion, Vendor shall hold all insurance policies and the proceeds thereof in trust for the parties as their interests may appear and in the event of substantial damage to the Property the Purchaser may either terminate this Agreement and have all monies paid by the Purchaser returned to the Purchaser without interest or deduction or else take the proceeds of any insurance and complete the purchase.

ARTICLE 8
PLANNING ACT

8.1 This Agreement is subject to the express condition that it is to be effective only if the subdivision control provisions of the *Planning Act* R.S.O. 1990, c. P.13 as amended (the "*Planning Act*") are complied with prior to Closing. The Vendor shall forthwith make any application to the local Committee of Adjustment or Land Division Committee for any consent that may be required pursuant to the *Planning Act*. In the event that any such application for consent is denied, or any condition imposed by such body is unacceptable to the Vendor, this Agreement shall be terminated.

ARTICLE 9
ADDITIONAL PROVISIONS

9.1 The Transfer/Deed of Land (the "**Transfer**"), and the Land Transfer Tax Affidavit, shall be prepared in registrable form by the Purchaser, and the Purchaser covenants at its cost to register the Transfer on Closing. If requested by Purchaser, Vendor covenants that the Transfer Deed to be delivered on completion shall contain the statements contemplated by s. 50(22) of the *Planning Act*.

9.2 Time shall in all respects be of the essence hereof provided that the time for doing or completing of any matter provided for herein may be extended or abridged by an agreement in writing signed by the Parties or by their respective solicitors who are specifically authorized in that regard.

9.3 Any tender of documents or money hereunder may be made upon the Parties or their respective solicitors on the day set for Closing. Money may be tendered by bank draft, uncertified cheque, or electronic funds transfer.

9.4 Notices to be given to either party shall be in writing, and will be sent via email, personally delivered or sent by registered mail (except during a postal disruption or threatened postal disruption), telegram, electronic facsimile or other similar means of prepaid recorded communication to the applicable address set forth below (or to such other address as such party may from time to time designate in such manner):

HYDRO ONE:	with a copy to its solicitors,
Hydro One Networks Inc. Facilities and Real Estate P.O. Box 4300 Markham, Ontario L2R 5Z5	Barriston LLP 90 Mulcaster St Barrie, ON L4M 4Y5
185 Clegg Road Markham, Ontario L3G 1B7	
Attention: Fax: (905) 946-6242	Attention: Jim McIntosh Fax: (705) 721-4025
OWNER:	**with a copy to their solicitors,**
«Owner_1_name_for_letters» «Owner_2_name_for_letters» «Owner_3_name_for_letters» «STREET_NUM» «STREET_NAME1» «MUNICIPALITY», «PROVINCE» «POSTAL_CODE»	**Solicitors Name** **Solicitors Address 1** **Solicitors Address 2** **Solicitors Address 3**
«SAP_Phone_Number» «SAP_email_address»	

Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5th) business day following the date on which it was sent. Any notice sent by email, telegram, electronic facsimile or other similar means of prepaid recorded communication shall be deemed to have been validly and effectively given on the Business Day next following the day on which it was sent. "Business Day" shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario.

9.5 The parties acknowledge that there are no covenants, representations, warranties, agreements or conditions, express or implied, collateral or otherwise, forming part of or in any way affecting or relating to this Agreement save as expressly set out in this Agreement and that this Agreement and all Schedules hereto constitute the entire agreement between the parties and may not be modified except as expressly agreed between the Vendor and Purchaser in writing. This Agreement shall be read with all changes of gender or number required by the context

9.6 If any provision or provisions of this Agreement be declared illegal or unenforceable, it or they shall be considered separate and severable from the Agreement and its remaining provisions shall remain in force and be binding upon the parties hereto as though the said provision or provisions had never been included.

9.7 No act or omission or delay in exercising any right or enforcing any term, covenant or agreement to be performed under this Agreement shall impair such right or be construed as to be a waiver of any default or acquiescence in such failure to perform, unless such waiver shall be given or acknowledged in writing.

9.8 This Agreement to Purchase shall be governed by and construed in accordance with the laws of the Province of Ontario.

9.9 This Agreement to Purchase shall enure to the benefit of and be binding upon the parties hereto and their respective heirs, attorneys, guardians, estate trustees, executors, trustees, successors and permitted assigns.

9.10 The Vendor warrants that, except to the extent such consent has been obtained, spousal consent is not necessary to this transaction and on Closing will not be necessary under the provision of the *Family Law Act*, R.S.O. 1990, c. F.3.

9.11 The Purchaser may, in its sole discretion and at its sole expense register this Agreement to Purchase or notice thereof on title to the Lands.

9.12 Where each of the Vendor and the Purchaser retain a solicitor to complete this Agreement and where the transaction contemplated herein will be completed by electronic registration pursuant to Part III of the *Land Registration Reform Act*, R.S.O. 1990, c. L.4 and any amendments thereto, the Vendor and the Purchaser acknowledge and agree that the delivery of documents and the release thereof to the Vendor and the Purchaser may, at the solicitor's discretion; (a) not occur contemporaneously with the registration of the Transfer/Deed of Land (and other registrable) documentation), and (b) be subject to conditions whereby the solicitor receiving documents and/or money will be required to hold them in trust and not release them except in accordance with the terms of a written agreement between the solicitors

9.13 The provisions of the attached Schedules "A", "A-1", "B" and "C" shall form part of this Agreement as if set out herein.

9.14 The Vendor represents and warrants and covenants that it is not now and on Closing will not be a non-resident of Canada within the meaning of the *Income Tax Act (Canada)*.

9.15 The Purchaser shall have the right to assign all or any part of its interest in this Agreement and any or all rights, privileges and benefits accruing to the Purchaser hereunder without the consent of the Vendor prior to or on the Closing. Upon and to the extent of such assignment, this Agreement shall thenceforth be construed as if originally made with such assignee or assignees instead of the Purchaser and the Purchaser shall, to the extent of such assignment, thereupon be relieved of all liabilities and obligations whatsoever arising out of this Agreement.

9.16 The parties hereto agree that any representations or covenants contained in this Agreement shall not merge on closing, but survive and continue in full force and effect thereafter, but only as to the accuracy of the representation or covenant as at the date of completion of this Agreement.

9.17 This Agreement may be executed in one or more counterparts, each of which shall be deemed an original and together shall constitute one and the same agreement. Counterparts may be executed either in original or by electronic means, including, without limitation, by facsimile transmission or by electronic delivery in portable document format (".pdf") or tagged image file format (".tif") and the parties shall adopt any signatures received by electronic means as original signatures of the Parties; provided, however that any party providing its signature in such manner shall promptly forward to the other party an original signed copy of this Agreement which was so delivered electronically.

9.18 The Vendor covenants and agrees to execute if necessary, at no further cost or condition to the Purchaser except payment of the Vendor's reasonable out-of-pocket costs, such other instruments, plans and documents as may reasonably be required by the Purchaser to effect the registration of any right or interest transferred hereunder or notice of this Agreement on title to the Lands.

9.19 The Purchaser agrees to pay the Vendor's reasonable legal costs in connection with this transaction.

9.20 The Vendor represents that the Vendor is at least 18 years of age.

IN WITNESS WHEREOF the parties hereto have duly executed this Agreement as of the Agreement Date.

WITNESS:	**OWNER:**
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_1_name_for_letters»**
Address:	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_2_name_for_letters»**
Address:	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_3_name_for_letters»**
Address:	
WITNESS:	The spouse of the Owner hereby consents to this Agreement
	SPOUSE OF OWNER:
	l/s
Name: Real Estate Representative	Name: **Property Owner Spouse Name**
Address:	

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________
Name:
Title:

I have authority to bind the Corporation

SCHEDULE "A"
LEGAL DESCRIPTION OF LANDS

«LEGAL_DESCRIPTION

SCHEDULE “A-1”
LEGAL DESCRIPTION OF PROPERTY

Legal description to be determined by deposited Reference Plan; Corridor Lands shown outlined in green.

****NOTE – Sketch shall be replaced by Corridor Lands description once applicable Reference Plan is deposited.**

Screenshot of ortho map with tower placements here

SCHEDULE “B”

PERMITTED ENCUMBRANCES

NIL

SCHEDULE “C”

CALCULATION SHEET

COMPENSATION AND INCENTIVE AGREEMENT – FEE SIMPLE

COMPENSATION AND INCENTIVE AGREEMENT – FEE SIMPLE

THIS COMPENSATION AND INCENTIVE AGREEMENT made as of the ___day of _______, 20___ (the "**Agreement Date**").

B E T W E E N:

«OWNER_1_NAME_FOR_LETTERS» & «OWNER_2_NAME_FOR_LETTERS» & «OWNER_3_NAME_FOR_LETTERS»

(hereinafter collectively called the "**Owner**")

OF THE FIRST PART

- and -

HYDRO ONE NETWORKS INC.

(hereinafter called "**Hydro One**")

OF THE SECOND PART

- and -

SPOUSE NAME

(hereinafter collectively called the "**Spouse**") This section is only filled out if the spouse is not on title

OF THE THIRD PART

RECITALS:

A. The Owner is the Owner of the lands and premises described in Schedule "A" attached hereto (the "**Lands**").

B. Hydro One desires to purchase a portion of the Lands (the "**Corridor Lands**"), as more particularly described in an Option Agreement between the parties hereto and having a date the same as this Compensation and Incentive Agreement (the "**Option Agreement**"), upon the terms and conditions set out in the Option Agreement.

C. Hydro One has offered to pay the Option Payment to the Owner upon execution of the Option Agreement and upon closing to purchase the Corridor Lands from the Owner for the Purchase Price (collectively, the "**Corridor Compensation**").

D. Hydro One has offered, on the terms and conditions set out herein, to compensate the Owner for injurious affection damages, if applicable (the "**IA Compensation**") in respect of that portion of the Lands which are not part of the Corridor Lands. Such injurious affection damages are calculated as shown on the calculation sheet attached hereto as Schedule "B" (the "**Calculation Sheet**").

E. To achieve a timely resolution of its land acquisition arrangements, Hydro One has also offered to pay certain incentives to the Owner on the terms and conditions set out in this Compensation and Incentive Agreement and as shown on the Calculation Sheet.

F. Any capitalized terms not defined in this Compensation and Incentive Agreement shall have the meaning ascribed to them in the Option Agreement.

NOW THEREFORE, the parties agree as follows:

1. **VALUATION**

(a) Hydro One has retained an external, independent AACI designated appraiser to determine the fair market value of the Corridor Lands and any applicable amount of IA Compensation, if any, as of XXXXDate and to prepare a report in respect thereof (the "**HONI Appraisal**"). The Owner acknowledges receiving a copy of the HONI Appraisal, and agrees to accept the amounts set out in the HONI Appraisal as a fair evaluation of the market value of the Owner's fee simple interest in the Corridor Lands as of the date of the HONI Appraisal.

(b) In recognition of a dynamic real estate market and that the effective date of One's appraised values in the HONI Appraisal are only relevant for a limited period of time, Hydro One shall provide a market value top-up where the passage of time between the HONI Appraisal Date and the date Hydro One exercises the Option Agreement is greater than one (1) year and such passage of time warrants such a top-up (the "**Top-Up**").

The amount of the Top-Up, if any, shall be the difference between (i) the market value set out in the HONI Appraisal, and (ii) the market value as of the date Hydro One exercises the Option Agreement (provided such date is at least one (1) year after the HONI Appraisal Date). The Top-Up shall only be applicable to the extent that the market value as of the date the Option Agreement is exercised is greater than the amount in the HONI Appraisal. Such adjustment shall be made for time only (change in market conditions) and based on an independent land rate study considering this singular factor. The land rate study will be prepared by an independent third party appraiser with an Accredited Appraiser Canadian Institute designation from the Appraisal Institute of Canada.

The Top-Up amounts will be paid by Hydro One to the Owner by adding the applicable amounts to the Purchase Price, Premium Above Fair Market Value, and the IA Compensation, if applicable.

2. **INCENTIVE PAYMENTS**

(a) Upon registration of the Option Agreement and this Compensation and Incentive Agreement by all parties thereto, Hydro One shall pay to or to the order of the Owner the Option Payment in the amount of **XXXXX ($XXXXX)** as set out on the Calculation Sheet.

(b) On the Closing Date, Hydro One shall make a further incentive payment to or to the order of the Owner in the amount of **XXXXX ($XX)**, (the "**Acceptance of the Hydro One Offer**") as set out on the Calculation Sheet.

(c) On the Closing Date, Hydro One shall make a further incentive payment to or to the order of the Owner in the amount of **XXXXX ($XX), (the "Premium Above Fair Market Value")** such amount being equal to XX% of the appraised fair market value of the Owner's fee simple interest in the Corridor Lands as set out on the Calculation Sheet.

3. **WAIVER**

The Owner waives the right to be reimbursed by Hydro One for the reasonable costs the Owner incurs for a third party independent appraisal report and/or legal review of the HONI Appraisal, the Option Agreement and this Compensation and Incentive Agreement, up to the amount of Seven Thousand Five Hundred Dollars ($7,500.00) and hereby accepts the Second Incentive Payment as defined in 2(b) above.

4. **IA COMPENSATION**

Hydro One agrees to pay to or to the order of the Owner on the Closing Date the IA Compensation, if applicable, in the amount of **XXXXX ($XX)** as set out on the Calculation Sheet.

5. CONVEYANCING

Hydro One agrees to reimburse the Owner for reasonably incurred legal fees, if any, associated with the review of applicable conveyancing documents.

6. TENANTS

The Owner agrees to indemnify and save harmless Hydro One from all actions, suits, costs, losses, charges, demands, claims and expenses for and in respect of any claims any person having a possessory interest in the Corridor Lands.

7. NOTICES

Notices to be given to either party shall be in writing, and will be sent via electronic mail ("email"), personally delivered or sent by registered mail (except during a postal disruption or threatened postal disruption), telegram, electronic facsimile or other similar means of prepaid recorded communication to the applicable address set forth below (or to such other address as such party may from time to time designate in such manner):

HYDRO ONE:

Hydro One Networks Inc.
Facilities and Real Estate
P.O. Box 4300
Markham, Ontario L2R 5Z5

185 Clegg Road
Markham, Ontario L3G 1B7

Attention:
Fax: (905) 946-6242

with a copy to its solicitors,

Barriston LLP
90 Mulcaster Street
Barrie, ON L4M 4Y5

Attention: Jim McIntosh
Fax: 705-721-4025

OWNER:

«Owner_1_name_for_letters» &
«Owner_2_name_for_letters» &
«Owner_3_name_for_letters»
«STREET_NUM» «STREET_NAME1»
«MUNICIPALITY», «PROVINCE»
«POSTAL_CODE»

«SAP_Phone_Number»
«SAP_email_address»

with a copy to their solicitors,

Solicitors Name
Solicitors Address 1
Solicitors Address 2
Solicitors Address 3

Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5th) business day following the date on which it was sent. Any notice sent by telegram, email, electronic facsimile or other similar means of prepaid recorded communication shall be deemed to have been validly and effectively given on the Business Day next following the day on which it was sent. "Business Day" shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario.

8. ASSIGNMENT OF AGREEMENT BY OWNER

The Owner shall not assign all or any part of its interest in this Compensation and Incentive Agreement or any of the rights, privileges and benefits accruing to the Owner hereunder without the consent of the Hydro One, which consent may not be unreasonably withheld or delayed. Upon and to the extent of such assignment, this Compensation and Incentive Agreement shall thenceforth be construed as if originally made with such assignee or assignees instead of the Owner and the Owner shall, to the extent of such assignment, thereupon be relieved of all liabilities and obligations whatsoever arising out of this Compensation and Incentive Agreement.

The Owner and, if applicable, the Spouse, each covenant and agree that if they transfer, assign, charge, lease or otherwise dispose of all or any part of their interest in the Lands (collectively, a "**Transfer**") they will obtain an agreement from such Transferee assuming and agreeing to be bound by all of the terms of this Compensation and Incentive Agreement as if the Transferee had been an original signatory to this Compensation and Incentive Agreement.

9. NOTICE OF AGREEMENT

Hydro One may, in its sole discretion and at its sole expense register this Compensation and Incentive Agreement or notice thereof on title to the Lands.

10. NO MERGER

The parties hereto agree that any representations or covenants contained in this Compensation and Incentive Agreement shall not merge on closing, but survive and continue in full force and effect thereafter, but only as to the accuracy of the representation or covenant as at the date of completion of this Compensation and Incentive Agreement.

11. ENTIRE AGREEMENT

The parties hereto acknowledge that there are no covenants, representations, warranties, agreements or conditions, express or implied, collateral or otherwise, forming part of or in any way affecting or relating to this Compensation and Incentive Agreement save as expressly set out in this Compensation and Incentive Agreement and that this Compensation and Incentive Agreement and all Schedules hereto constitute the entire agreement between the parties and may not be modified except as expressly agreed between the parties in writing.

12. SEVERABILITY

Any provision or provisions of this Compensation and Incentive Agreement is declared illegal or unenforceable, it or they shall be considered separate and severable from this Compensation and Incentive Agreement and the remaining provisions shall remain in force and be binding upon the parties hereto as though the said provision or provisions had never been included.

13. GOVERNING LAW

This Compensation and Incentive Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario.

14. SPOUSAL CONSENT

The Owner represents that, except to the extent such consent has been obtained, spousal consent to this transaction is not necessary under the provision of the *Family Law Act*, R.S.O. 1990, c. F.3.

15. SUCCESSORS AND ASSIGNS

This Compensation and Incentive Agreement shall enure to the benefit of and be binding upon the parties hereto and their respective heirs, attorneys, guardians, estate trustees, executors, trustees, successors and permitted assigns.

16. EXECUTION AND DELIVERY

This Compensation and Incentive Agreement may be executed and delivered in counterparts by original, facsimile or scanned e-mail copy and each Compensation and Incentive Agreement shall constitute and be deemed to be the entire agreement notwithstanding that all copies of this Compensation and Incentive Agreement may not have all signatures.

17. FURTHER ASSURANCES

The parties hereto agree to do, make and execute, if necessary, at no further cost or condition to the other except payment of reasonable out-of-pocket costs, such other instruments, plans, documents, acts, matters and things and take such further action as may reasonably be required by the other party in order to effectively carry out the true intent of this Compensation and Incentive Agreement.

18. AGE

The Owner represents that the Owner is at least 18 years of age.

IN WITNESS WHEREOF the parties hereto have duly executed this Compensation and Incentive Agreement as of the Agreement Date.

WITNESS:	**OWNER:**
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_1_name_for_letters»**
Address:	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_2_name_for_letters»**
Address:	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_3_name_for_letters»**
Address:	
WITNESS:	The spouse of the Owner hereby consents to this Compensation and Incentive Agreement
	SPOUSE OF OWNER:
	l/s
Name: «Real_Estate_Representative»	Name: **Property Owner Spouse Name**
Address:	

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________

Name:
Title:

I have authority to bind the Corporation

SCHEDULE “A”

LANDS

«LEGAL_DESCRIPTION»

SCHEDULE “B”

CALCULATION SHEET

AGREEMENT FOR TEMPORARY RIGHTS

THIS AGREEMENT made in duplicate the _____ day of______________ 202X.

Between:

[INSERT SUBJECT PROPERTY LEGAL OWNER]

(hereinafter referred to as the "Grantor")

OF THE FIRST PART

--- and ---

HYDRO ONE NETWORKS INC.

(hereinafter referred to "HONI")

OF THE SECOND PART

WHEREAS the Grantor is the owner in fee simple and in possession of certain lands legally described as [INSERT SUBJECT PROPERTY LEGAL DESCRIPTION] being PIN: [INSERT SUBJCT PROPERTY PIN], collectively referred to as the "Lands".

WHEREAS HONI desires the right to enter onto and use a portion of the Lands in connection with the [INSERT PROJECT REQUIRING THE TEMPORARY SITE] (the "Project").

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the fee of XXXXX Dollars ($XXXX) plus harmonized sales tax ("HST") per month (the "Monthly Rent") to be paid by HONI to the Grantor, and the mutual covenants herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. The Grantor hereby grants, conveys and transfers to HONI in, over, along and upon that part of the Lands highlighted in red as shown in Schedule "A" attached hereto (the "Material Laydown Area"), the rights and privileges as follows:

(a) for the servants, agents, contractors and workmen of HONI at all times with all necessary vehicles and equipment to pass and repass over the Lands for the purpose of access to the Material Laydown Area;

(b) to store, use and maintain upon the Material Laydown Area, construction equipment and machinery as may be necessary for HONI's purposes;

(c) to place upon the Material Laydown Area, temporary trailers as may be necessary for HONI's purposes of a construction field office for the purposes of the Project; and

(d) to cut and remove all trees, brush and other obstructions made necessary by the exercise of the rights granted hereunder

2. The term of this Agreement and the permission granted herein shall be a term of XX (XX) months commencing on [INSERT DATE OF COMMENCEMENT] and ending [INSERT DATE OF EXPIRY] (the "Term"). HONI may, in its sole option, and upon 30 days' notice to the Grantor, extend the Term on a month to month basis for up to an additional XX (XX) months, under the same provisions and conditions contained in this Agreement, including the Monthly Rent.

3. Upon the expiry of the Term or any extension thereof, HONI shall remove and repair any physical damage to the Material Laydown Area and/or Lands resulting from HONI's use of the Material Laydown Area and the permission granted herein; and, shall restore the Material Laydown Area to its original condition so far as reasonably practicable.

4. The total amount of the Monthly Rent shall be paid in full by HONI at the commencement of the Term. For clarity, HONI shall pay the total amount of XXXX Dollars ($XXX) plus HST at the commencement of the Term.

5. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Material Laydown Area shall be at the sole risk of HONI and the Grantor shall not be liable for any loss or damage or injury (including loss of life) to them or it however occurring except and to the extent to which such loss, damage or injury is caused by the negligence or willful misconduct of the Grantor.

6. HONI agrees that it shall indemnify and save harmless the Grantor from and against all claims, demands, costs, damages, expenses and liabilities (collectively the "Costs") whatsoever arising out of HONI's presence on the Material Storage Yard Area or of its activities on or in connection with the Material Storage Yard Area arising out of the permission granted herein except to the extent any of such Costs arise out of or are contributed to by the negligence or willful misconduct by the Grantor.

7. Notices to be given to either party shall be in writing, personally delivered or sent by registered mail (except during a postal disruption or threatened postal disruption), telegram, electronic facsimile or other similar means of prepaid recorded communication to the applicable address set forth below (or to such other address as such party may from time to time designate in such manner):

TO HONI:

Hydro One Networks Inc.
Real Estate Services
1800 Main Street East
Milton, Ontario L9T 753

Attention:
Tel:

TO GRANTOR:

XXXXXXX
XXXXXXX
XXXXXXX

Attention:
Tel:

8. Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5^{th}) business day following the date on which it was sent. Any notice sent by telegram, electronic facsimile or other similar means of prepaid recorded communication shall be deemed to have been validly and effectively given on the Business Day next following the day on which it was sent. "Business Day" shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable herein. The parties hereto submit themselves to the exclusive jurisdiction of the Courts of the Province of Ontario.

9. Any amendments, modifications or supplements to this Agreement or any part thereof shall not be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of this Agreement.

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the day and year first above written.

[INSERT SUBJECT PROPERTY LEGAL OWNER]

Grantor's HST Registration Number

Name:
Title:

I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

Name:
Title:

I have authority to bind the Corporation

SCHEDULE "A"

*Sketch for reference only, not to scale.

OFF CORRIDOR ACCESS

THIS AGREEMENT made in duplicate the ___________day of _____________2021

Between:

XXXXXXXXX

(hereinafter referred to as the "Grantor")
OF THE FIRST PART

--- and ---

HYDRO ONE NETWORKS INC.

(hereinafter referred to as "HONI")
OF THE SECOND PART

WHEREAS the Grantor is the owner in fee simple and in possession of certain lands legally described as ***(INSERT LEGAL DESCRIPTION)*** **(the "Lands").**

WHEREAS The Grantor has entered into a Temporary Access Agreement with HONI on a portion of the Lands highlighted in green in Schedule "A" (the "Access Lands"). HONI will be utilizing a portion of the Lands as a means of off-corridor access highlighted in red in Schedule "A" ("Off-Corridor Access Lands").

WHEREAS the Owner is agreeable in allowing HONI to enter onto the Lands to use the Off-Corridor Access Lands in order to commence activities which shall include necessary real estate, environmental and engineering studies and testing including but not limited to borehole testing, archaeological studies, soil assessments, property appraisals and surveys in, on or below the Lands subject to the terms and conditions contained herein (the "Activities").

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the lump sum of **$XXXXX.00** now paid by HONI to the Owner, and the respective covenants and agreements of the parties hereinafter contained and other valuable consideration, the receipt and sufficiency of which are hereby acknowledged by the parties hereto, the parties hereto agree as follows:

1. The Grantor hereby grants to HONI the right to enter upon the Lands for the purpose of Off-Corridor Access Lands.

2. The Grantor hereby grants to HONI, as of the date this Agreement, (i) the right to enter upon and exit from, and to pass and repass at any and all times in, over, along, upon, across, through and under the Off-Corridor Access Lands as may be reasonably necessary, at all reasonable times, for HONI and its respective officers, employees, workers, permittees, servants, agents, contractors and subcontractors, with or without vehicles, supplies, machinery, plant, material and equipment for the purpose of the Activities, subject to payment of compensation for damages including payment for crops caused thereby. HONI agrees that it shall take all reasonable care while undertaking the Activities.

3. The term of this Agreement and the permission granted herein shall be two (2) years from the date written above (the "Term"). HONI may, in its sole discretion, and upon 10 days notice to the Grantor, extend the Term for an additional length of time, which shall be negotiated between the parties.

4. Upon the expiry of the Term or any extension thereof, HONI shall repair any physical damage to the Off-Corridor Access Lands and/or Lands resulting from HONI's use of the Access Lands and the permission granted herein; and, shall restore the Access Lands to its original condition so far as possible and practicable.

5. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Off-Corridor Access Lands shall be at the sole risk of HONI and the Grantor shall not be liable for any loss or damage or injury (including loss of life) to them or it however occurring except and to the extent to which such loss, damage or injury is caused by the negligence or willful misconduct of the Grantor.

6. HONI agrees that it shall indemnify and save harmless the Grantor from and against all claims, demands, costs, damages, expenses and liabilities (collectively the "Costs") whatsoever arising out of HONI's presence on the Off-Corridor Access Lands or of its activities on or in connection with the Off-Corridor Access Lands arising out of the permission granted herein except to the extent any of such Costs arise out of or are contributed to by the negligence or willful misconduct by the Grantor.

7. Notices to be given to either party shall be in writing, personally delivered or sent by registered mail (except during a postal disruption or threatened postal disruption), telegram, electronic facsimile to the applicable address set forth below (or to such other address as such party may from time to time designate in such manner):

TO HONI:

Hydro One Networks Inc.
Real Estate Services
1800 Main Street East
Milton, Ontario L9T 7S3

Attention:	Real Estate Acquisitions
Tel:	905-875-2508
Fax:	905-878-8356

TO GRANTOR:

XXXXXXXX
XXXXXXXX

8. Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5^{th}) business day following the date on which it was sent. Any notice sent by telegram, electronic facsimile or shall be deemed to have been validly and effectively given on the Business Day next following the day on which it was sent. "Business Day" shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable herein. The parties hereto submit themselves to the exclusive jurisdiction of the Courts of the Province of Ontario.

9. Any amendments, modifications or supplements to this Agreement or any part thereof shall not be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of this Agreement.

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the day and year first above written.

SIGNED, SEALED & DELIVERED In the presence of: ____________________ Witness	**OWNER(S):** ____________________ **Name:**
SIGNED, SEALED & DELIVERED In the presence of: ____________________ Witness	____________________ **Name:**

HYDRO ONE
HST # 870 865 821 RT001

HYDRO ONE NETWORKS INC.

By: ____________________

Name:

Title:

I have authority to bind the Corporation

SCHEDULE "A"

PROPERTY SKETCH

DAMAGE CLAIM AGREEMENT/WAIVER

THIS MEMORANDUM OF AGREEMENT dated the ____ day of ___________, 20____

Between:

[INSERT NAME OF OWNER]

herein called the "**Claimant**"

- and-

Hydro One Networks Inc.

herein called the "**Hydro One**"

Witnesseth:

The Claimant agrees to accept: XXXXXXX ($XXX.XX) in full payment and satisfaction of all claims or demands for damages of whatsoever kind, nature or extent which may have been done to date by Hydro One during the construction, completion, operation or maintenance of the works of Hydro One constructed on [INSERT LEGAL DESCRIPTION] which property the Claimant is the legal owner and which damages may be approximately summarized and itemized as:

[INSERT DESCRIPTION OF DAMAGE]

Area

TOTAL $

.

Subject to Approval by Hydro One Networks Inc.

Witness

____

Signature

____

Signature

SYSTEM IMPACT ASSESSMENT

Please refer to **Attachment 1** of this Schedule for the Draft SIA prepared by the IESO (SIA reference # CAA 2025-834).

The Draft SIA concludes that the Project is expected to have no material adverse impact on the reliability of the integrated power system, provided that all requirements in this SIA are implemented.

Hydro One expects to receive the IESO's Final SIA shortly and will submit it on the Application's record at that time.

Hydro One confirms that it will implement the requirements noted by the IESO in the SIA.

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SYSTEM IMPACT ASSESSMENT

System Impact Assessment Report

Draft or Final Report - Confidential

CAA ID: 2025-834
Project: Hawthorne x Orleans Transmission Reinforcement
Connection Applicant: HYDRO ONE NETWORKS INC.

May 4, 2026

ieso
Connecting Today.
Powering Tomorrow.

Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of conditional approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Conditional approval of the project is based on information provided to the IESO by the connection applicant and Hydro One at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by Hydro One at the request of the IESO. Furthermore, the conditional approval is subject to further consideration due to changes to this information, or to additional information that may become available after the conditional approval has been granted.

If the connection applicant has engaged a consultant to perform connection assessment studies, the connection applicant acknowledges that the IESO will be relying on such studies in conducting its assessment and that the IESO assumes no responsibility for the accuracy or completeness of such studies including, without limitation, any changes to IESO base case models made by the consultant. The IESO reserves the right to repeat any or all connection studies performed by the consultant if necessary to meet IESO requirements.

Conditional approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed project to the IESO-controlled grid. However, the conditional approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter(s) during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. This report does not in any way constitute an endorsement of the proposed connection for the purposes of obtaining a contract with the IESO for the procurement of supply, generation, demand response, demand management or ancillary services.

The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, the connection applicant must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to the connection applicant. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used. The IESO provides no comment, representation or opinion, express or implied, with respect to who should bear the cost of IESO requirements for connection in this report and disclaims any liability in connection therewith.

Hydro One

The results reported in this report are based on the information available to Hydro One, at the time of the study, suitable for a System Impact Assessment of this connection proposal.

The short circuit and thermal loading levels have been computed based on the information available at the time of the study. These levels may be higher or lower if the connection information changes as a result of, but not limited to, subsequent design modifications or when more accurate test measurement data is available.

This study does not assess the short circuit or thermal loading impact of the proposed facilities on load and generation customers.

In this report, short circuit adequacy is assessed only for Hydro One circuit breakers. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One circuit breakers and identifying upgrades required to incorporate the proposed facilities. These results should not be used in the design and engineering of any new or existing facilities. The necessary data will be provided by Hydro One and discussed with any connection applicant upon request.

The ampacity ratings of Hydro One facilities are established based on assumptions used in Hydro One for power system planning studies. The actual ampacity ratings during operations may be determined in real-time and are based on actual system conditions, including ambient temperature, wind speed and facility loading, and may be higher or lower than those stated in this study.

The additional facilities or upgrades which are required to incorporate the proposed facilities have been identified to the extent permitted by a System Impact Assessment under the current IESO Connection Assessment and Approval process. Additional facility studies may be necessary to confirm constructability and the time required for construction. Further studies at more advanced stages of the project development may identify additional facilities that need to be provided or that require upgrading.

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Project Description

Hydro One Networks Inc. (the "connection applicant" and "transmitter") is planning the following changes to the IESO-Controlled Grid (the "project"):

- Build a new 11.3 km long 230 kV circuit A25, between Hawthorne TS and Orleans TS.
- Replace a 11.2 km section of the existing 115 kV circuit H9A, between Hawthorne TS and Orleans TS.
- Replace the existing 50/66.7/83.3 MVA 110/28 kV transformer T1 at Orleans TS with a new 75/100/125 MVA 230/27.6/27.6 kV transformer. Orlean TS transformer T1 will tap to the new 230 kV circuit A25.
- Install a new 230 kV circuit breaker KL25 at the Hawthorne TS
- Install three new 27.6 kV circuit breakers at Orleans TS.
- Transfer Bilberry TS existing load to the Mer Bleue MTS.

The project is planned to be in-service by Q2 2029.

Notification of Conditional Approval

This assessment concludes that the proposed connection of the project is expected to have no material adverse impact on the reliability of the integrated power system, provided that all requirements in this report are implemented. Therefore, the assessment supports the release of the Notification of Conditional Approval for connection of the project.

Assessment Findings

System studies were carried out to identify the impact of the project on loading of transmission facilities, system voltages, voltage stability, transient performance, load security, and restoration and to verify that the applicable reliability standards are met. The studied scenarios and main assumptions are available in Appendix D of this report. The detailed study results are available in Appendix E of this report. Based on the assessment results, we have identified the following findings.

1. Under planning events where both KL25 and DL42 230 kV circuit breakers are open, the new transmission line A25 will become radially connected to A42T. This configuration can result in reverse active power flow through transformer T2 at Orleans TS and significantly reduce the short circuit level at Outaouais TS, potentially leading to unstable operation of the Ontario – Quebec high-voltage direct current (HVdc) interconnection facilities.
2. The Project will change one of Orleans TS tapped circuits from 115 kV circuit H9A to the new 230 kV circuit A25. Accordingly, the Under Voltage Load Shedding (UVLS) and shunt capacitor automatic switching settings shall be updated.

IESO Requirements for Connection

Specific Requirements:

The following specific requirements are applicable for the incorporation of the project and its connection facilities. Specific requirements pertain to the level of reactive power compensation needed, operation restrictions, special protection system, upgrading of equipment and any project specific items not covered in the general requirements.

Requirements for the Connection Applicant and the transmitter

1. To address finding #1, the connection applicant (the "transmitter") shall implement cross tripping scheme to trip KL42 (L25L42) breaker when both KL25 and DL42 breakers are open. Additionally, to prevent the reverse active power flow through transformer T1 at Orleans TS or voltage collapse at Mer Bleue MTS, a transfer trip signal shall be sent to Mer Bleue MTS tripping transformer T2 HV side breaker.

2. To address finding #2, the connection applicant (the "transmitter") shall revise UVLS and shunt capacitor auto switching settings at Orleans TS. The UVLS shall operate if the voltage at any of the 230 kV buses drops below 205 kV for 1.5 seconds. Orlean TS shunt capacitor SC1 shall be automatically switched on when the voltage at any of the 230 kV buses drops below 220 kV for 5 seconds, and shall be switched off when the voltage at any of the 230 kV buses exceeds 250 kV for 5 seconds.

   During the IESO Market Registration process, a revised Facility Description Document (FDD) for Ottawa area UVLS (FDD-1029) must be provided and finalized at least nine months prior to the in-service date. The FDD must contain the finalized scheme as well as expected operating times.

General Requirements:

The connection applicant shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code (TSC) and reliability standards. Some of the general requirements that are applicable to this project are presented in detail in Appendix A: General Requirements of this report.

Recommendation

1. Power transformers with a high side, wye grounded winding with terminal voltage greater than 200 kV are subject to North American Electric Reliability Corporation (NERC) standard TPL-007, Transmission System Planned Performance for Geomagnetic Disturbance Events. As per NERC standard TPL-007, the Planning Coordinator in conjunction with its Transmisson Planner are required to implement a process(es) to obtain Geomagnetic Disturbance (GMD) measurement data, via geomagnetically-induced currents (GIC) monitors, which will aid in model validation and situational awareness. This data will more accurately support the owner of the applicable power transformer(s) to conduct a thermal impact assessment if required in the future. As such, it is recommended that the connection applicant makes provision(s) to install monitoring equipment for GIC on the new transformer(s).

Appendix A: General Requirements

The connection applicant shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code and reliability standards. This section highlights some of the general requirements that are applicable to the project.

1. The connection applicant must notify the IESO at connection.assessments@ieso.ca as soon as they become aware of any changes to the project scope or data used in this assessment. The IESO will determine whether these changes require a re-assessment.
2. The connection applicant shall ensure that the BPS elements are in compliance with the applicable NPCC criteria and the BES elements are in compliance with the applicable NERC reliability standards. To determine the standard requirements that are applicable, the IESO provides mapping tools titled "NPCC Criteria Mapping Spreadsheet" for BPS elements and "NERC Reliability Standard Mapping Tool/Spreadsheet" for BES elements at the IESO's website of Applicability Criteria for Compliance with Reliability Requirements.

   Note, the connection applicant may request an exception to the application of the BES definition. The procedure for submitting an application for exemption can be found in Market Manual 11.4: "Ontario Bulk Electric System (BES) Exception" at the IESO's website.

   The IESO's criteria for determining applicability of NERC reliability standards and NPCC Criteria can be found in the Market Manual 11.1: "Applicability Criteria for Compliance with NERC Reliability Standards and NPCC Criteria" at the IESO's website.

   Compliance with these reliability standards will be monitored and assessed as part of the IESO's Ontario Reliability Compliance Program. For more details about compliance with applicable reliability standards, the connection applicant is encouraged to contact orcp@ieso.ca and also visit the Ontario Reliability Compliance Program webpage.

   However, like any other system element in Ontario, the BPS and BES classifications of the project will be periodically re-evaluated as the electrical system evolves.
3. The connection applicant shall ensure that the load facility has the capability to operate continuously between 59.4 Hz and 60.6 Hz and remain operational for a limited time beyond this range, in alignment with IESO, NERC, and NPCC frequency ride-through requirements for generators.

   The IESO may require changes to frequency ride-through settings based on updates in NERC or Market Rules requirements. Changes to these settings shall not be enabled without IESO approval.
4. In accordance with Appendix 4.3 of the Market Rules, the connection applicant shall ensure the project has the capability to ride-through routine switching events and design criteria contingencies on the transmission system assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times, unless disconnection by configuration or a lower level ride-through capability has been approved by the IESO.

   The connection applicant shall ensure that the project's equipment can operate continuously within the voltage requirements specified in section 2.4.2 and section 2.4.3 of the Ontario

Resource and Transmission Assessment Criteria (ORTAC) and remain operational for no less than 5 seconds beyond ORTAC post-contingency voltage limits.

The connection applicant will be required to demonstrate the project's voltage ride-through capability during commissioning by either providing manufacturer test results or monitoring several variables under a set of IESO specified field tests, and the test results must be verifiable using the dynamic models provided for the project.

The connection applicant will be required to take corrective actions that could include upgrades to the project, if the performance of their facilities becomes inadequate or causes any adverse impact on the IESO-controlled grid (e.g. tripping for out of zone faults) after the project is in-service. If upgrades are needed, the IESO may direct the transmitter or the distributor to disconnect the project until such upgrades are deployed, to the satisfaction of the IESO. Automatic reconnection of the loads to the system is not allowed.

The IESO may require changes to voltage ride-through settings based on updates in NERC or Market Rules requirements. Changes to these settings shall not be enabled without IESO approval.

5. According to Section 6.1.2 of the TSC, the connection applicant must ensure the project's transmission connection equipment is designed to withstand the fault levels in the area. According to Section 6.4.4 of the TSC, if any future system changes result in an increased fault level higher than the project's equipment capability, the connection applicant is required to replace that equipment with higher rated equipment capable of withstanding the increased fault level, up to the maximum fault level specified in Appendix 2 of the TSC.

   It is the connection applicant's responsibility to verify that all equipment and circuit breakers within the project are appropriately sized for the local fault levels.

   The connection applicant shall ensure that the circuit breakers installed at the project have rated interrupting time that satisfies Appendix 2 of the TSC. Fault interrupting devices installed at the project must be able to interrupt fault currents at the applicable maximum continuous voltage as specified in Section 2.4.2 and Section 2.4.3 of ORTAC.

6. The connection applicant shall ensure that the protection systems are designed to satisfy all the requirements of the TSC. New protection systems must be coordinated with existing protection systems. Protection systems within the project shall only trip the appropriate equipment isolating the fault.

   Associated overvoltage protective relaying must be set to ensure that the project's equipment does not automatically trip for voltages up to 5% above the equipment's corresponding maximum continuous voltage as specified in section 2.4.2 of the ORTAC.

   BPS elements are deemed by the IESO to be essential to system reliability and security and must be protected by redundant protection systems in accordance with Section 8.2 of the TSC. These redundant protection systems must satisfy all requirements of the TSC, and in particular, they must be physically separated and not use common components, common battery banks, or common instrument transformer secondary windings.

   The protection systems for transmission voltage BES elements (whose rated voltage is higher than 100 kV) must be redundant. Redundancy must be present in protective relaying for normal fault clearing and control circuitry associated with protective functions including trip coils of the circuit breakers or other interrupting devices. These redundant protection systems must not use common instrument transformer secondary windings. A single communication system, if used, must be monitored and reported and a single DC supply, if used, must be monitored and reported for both low voltage and open circuit.

As the electrical system evolves, transmission voltage non-BPS or non-BES elements (whose rated voltage is higher than 100 kV) within the project, may be re-classified as BPS elements or BES elements. The connection applicant is recommended to design the protection systems for these elements according to the protection requirements for BPS elements or have adequate provisions for future upgrade to meet those requirements.

7. The connection applicant shall ensure that the connection equipment is designed to be fully operational in all reasonably foreseeable ambient conditions. Failures of the connection equipment must be contained within the project and have no adverse impact on the IESO-controlled grid.

8. The connection applicant shall ensure that the telemetry requirements for the project are satisfied as per the applicable Market Rules requirements. The finalization of telemetry quantities and telemetry testing will be conducted during the IESO's Market Registration process.

9. In accordance with Section 7.4 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.16 of the Market Rules on a continual basis. The data shall be provided in accordance with the performance standards set forth in Appendix 4.20 and Appendix 4.21, subject to Section 7.6A of Chapter 4 of the Market Rules. Additional telemetry quantities may be applicable. The whole telemetry list will be finalized during the IESO's Market Registration process.

   The connection applicant must install monitoring equipment that meets the requirements set forth in Appendix 2.2 of Chapter 2 of the Market rules. As part of the IESO's Market Registration process, the connection applicant must also complete end to end testing of all necessary telemetry points with the IESO to ensure that standards are met and that sign conventions are understood. All found anomalies must be corrected before IESO's final approval to connect any phase of the project is granted.

10. The connection applicant must initiate the IESO's Market Registration process at least eight months prior to the commencement of any project related outages.

    The connection applicant is required to provide "as-built" equipment data for the project during the IESO Market Registration process. If the submitted equipment data differ materially from the ones used in this assessment, then further analysis of the project may need to be done by the IESO before final approval to connect is granted.

    As part of the IESO Market Registration process, the connection applicant must also provide evidence to the IESO confirming that the project's equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in this assessment. This evidence shall be either type tests done in a controlled environment or commissioning tests done on-site. In either case, the testing must be done not only in accordance with widely recognized standards, but also to the satisfaction of the IESO. Until this evidence is provided and found acceptable to the IESO, the Market Registration process will not be considered complete and the connection applicant must accept any restrictions the IESO may impose upon this project's participation in the IESO-administered markets or connection to the IESO-controlled grid. The evidence must be supplied to the IESO within 30 days after completion of commissioning tests. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

If the submitted models and data differ materially from the ones used in this assessment, then further analysis of the project may need to be done by the IESO before final approval to connect is granted.

At the sole discretion of the IESO, performance tests may be required at generation and transmission facilities. The objectives of these tests are to demonstrate that equipment performance meets the IESO requirements, and to confirm models and data are suitable for IESO purposes. The transmitter may also have its own testing requirements. The IESO and the transmitter will coordinate their tests, share measurements and cooperate on analysis to the extent possible.

Once the IESO's Market Registration process has been successfully completed, the IESO will provide the connection applicant with a Registration Approval Notification (RAN) document, confirming that the project is fully authorized to connect to the IESO-controlled grid. For more details about this process, the connection applicant is encouraged to contact IESO's Market Registration at market.registration@ieso.ca.

Be advised that any registration changes could have an impact on a market participant's monthly global adjustment charges. Such registration changes include but are not limited to:

- New facility registrations
- Modifications to existing facility registration
- Electrical configuration changes
- Meter installation reconfigurations
- Full or partial transfers of a facility to a separate legal entity
- Transferring a facility between the retail electricity market and the IESO-administered wholesale electricity market (IAM)

Note that any newly registered facility in the IAM will automatically be treated as a Class B facility, unless stated otherwise in Ontario Regulation 429/04. It is the sole responsibility of the market participant to declare if any such provisions of Ontario Regulation 429/04 are applicable.

Subject to compliance with all regulatory requirements, a new facility may become eligible to participate in the Industrial Conservation Initiative (ICI) program (i.e. to be treated as a Class A facility) after the facility has been registered in the IAM for the entire duration of a base period (i.e. the facility has registered withdrawals from the IESO-controlled grid from May 1 to April 30 of the following calendar year).

11. The connection applicant shall ensure the wholesale metering installations comply with (i) the Ontario Market Rules, e.g., Chapter 6 - Wholesale Metering, Chapter 6 - Appendices, Chapter 9 - Settlements and Billing, Chapter 9 - Appendices, Chapter 10-Transmssion Service and Planning, (ii) the applicable market manuals, e.g., Market Manual 3 Series: Metering, and (iii) IESO wholesale metering hardware standards and policies. The connection applicant is encouraged to

seek advice from a metering service provider (MSP) or from the IESO in early stages of the project design.

12. As per Market Manual 1.4: Connection Assessment and Approval, the connection applicant will be required to provide a status report of its proposed project with respect to its progress upon request of the IESO using the project status report form on the IESO website. Failure to comply with project status requirements listed in Market Manual 1.4: Connection Assessment and Approval will result in the project being withdrawn.

    The connection applicant will be required to also provide updates and notifications in order for the IESO to determine if the project is "committed" as per Section 3.3 of Market Manual 1.4: Connection Assessment and Approval.

Disclaimer of Confidentiality

Appendices B to E, inclusive, contain confidential information of the IESO, the connection applicant, the transmitter and, potentially, other third parties, including information that, if disclosed, could reasonably be expected to pose a potential security threat to the *integrated power system*, the *IESO-administered markets*, or those of neighbouring jurisdictions.

Appendices B to E are intended only to be disclosed to, and may only be used on a confidential basis by the connection applicant and transmitter. The connection applicant and transmitter may not, except as permitted by Section 5.3 of Chapter 3 of the Market Rules, disclose or use such information, other than for the purpose of carrying out its responsibilities as described in Section 6 of Chapter 4 of the Market Rules, the Transmission System Code and Market Manual 1.4.

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
facebook.com/OntarioIESO
linkedin.com/company/IESO

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CUSTOMER IMPACT ASSESSMENT

Please refer to **Attachment 1** of this Schedule for the Draft CIA prepared by Hydro One. The Draft CIA concludes that the Project is expected to have no material adverse impact on the reliability of the transmission connected customers in the area, as fault levels at the buses remain within the limits prescribed by the TSC.

Hydro One expects to finalize the CIA following the receipt of the IESO's Final SIA and once all customer comments on the Draft CIA have been addressed. Once finalized, Hydro One will submit it on the Application's record.

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DRAFT CUSTOMER IMPACT ASSESSMENT

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

CUSTOMER IMPACT ASSESSMENT

HAWTHORNE X ORLEANS TRANSMISSION REINFORCEMENT

CIA ID:
Revision: Draft
Date: 27 April 2026

Issued by:
System Planning Division
Hydro One Networks Inc.

Prepared by:

Jean Morneau
Sr. Network Management Engineer
System Planning Division
Hydro One Networks Inc.

Approved by:

Ajay Garg
Manager Transmission Planning –East
System Planning Division
Hydro One Networks Inc.

Disclaimer

This Customer Impact Assessment ("CIA") is being performed in accordance with Hydro One Networks Inc.'s ("Hydro One") Customer Impact Assessment Procedure (Section 2.4) in Hydro One's Ontario Energy Board (OEB) approved Transmission Connection Procedures) and Section 6.41 of the OEB's Transmission System Code ("Code"). Hydro One performs a CIA where Hydro One has determined prior to conducting the CIA that one or more existing Hydro One transmission customers may be impacted by a proposed new or modified connection ("Proposed Project"). The CIA is intended to highlight impacts of the Proposed Project, if any, on existing Hydro One transmission customers early in the project development process and also provide an opportunity for existing Hydro One transmission customers that may be impacted by the Proposed Project to bring forward any concerns that they may have.

Please note that:

- the fault levels computed by Hydro One as part of this CIA are meant to assess current conditions and are not to be used by any person to size equipment or make other design decisions; and
- the estimate of the outage requirements identified in this CIA are subject to change to accommodate the requirements of the IESO and other regulatory or municipal authority requirements.

Hydro One may revise the result(s) of this CIA and issue CIA revision(s):

(i) where there are subsequent changes to the Proposed Project, the required transmission system modifications or the implementation plan that changes the impact of the Proposed Project on one or more existing connected transmission customers; and

(ii) to accommodate the IESO's requirements in respect of the Proposed Project identified in either the System Impact Assessment (SIA) or any revision(s) of the SIA for the Proposed Project.

Hydro One shall not be liable to anyone (including, without limitation, any existing transmission customer that Hydro One determined may be impacted by the Proposed Project) under any circumstances whatsoever for any: (i) direct damages resulting from or in any way related to the reliance on, acceptance or use of the CIA (and where applicable, any CIA revision(s)), in whole or in part, unless such liability arises under section 6.4 of the Code or the terms of a contract made between Hydro One and that person or entity with respect to the Proposed Project; and/or (ii) indirect or consequential damages, loss of profit or revenues, business interruption losses, loss of contract or loss of goodwill, special damages, punitive or exemplary damages, whether any of the said liability, loss or damages arises in contract, tort or otherwise.

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CUSTOMER IMPACT ASSESSMENT

HAWTHORNE X ORLEANS TRANSMISSION REINFORCEMENT

1.0 INTRODUCTION

1.1 Purpose

Hydro One is proposing modifying the existing supply to the Orleans area by adding a new 230kV circuit and upgrading Orleans TS. The project is a recommendation of the Greater Ottawa Technical Working Group (TWG).

This Customer Impact Assessment (CIA) study assesses the potential impact of the new 230kV circuit on the transmission connected customer of the area.

In accordance with section 6 of the Ontario Energy Board's Transmission System Code ("TSC"), Hydro One Networks Inc. ("Hydro One") is to carry out a Customer Impact Assessment ("CIA") study to assess the potential impact of the proposed project on existing transmission customers in the affected area. As part of the Connection Assessment and Approval ("CAA") process, impact of the project on the bulk electricity system is the subject of the System Impact Assessment ("SIA"), which was carried out by the Independent Electricity System Operator ("IESO").

This CIA study is intended to supplement the SIA report CAA ID 2025-834, draft dated 31 March 2026, which assessed the Hawthorne x Orleans Transmission Reinforcement project and concluded that there is no adverse impact of this proposed project on the transmission system.

This draft CIA study report is being issued to all area transmission customers being affected by the proposed work for review and comments.

1.2 Background

The Orleans area is supplied by two 115kV circuits (A2 and H9A), and one 230kV circuit (D5A). Circuits D5A and H9A are on the same towers and are in the southern part of the area, whereas circuit A2 is a single tower circuit and on the northern part of the area. The two main stations supplying the area are Bilberry Creek TS which is supplied by A2 and H9A, and Orleans TS which is supplied by 230kV D5A and 115kV H9A.

In the 2020 Regional Planning for the Greater Ottawa region, the Orleans area was reviewed, and it was determined that the existing system configuration was adequate to meet the expected demand using the existing 115kV and 230kV stations. However, as further information became available after the publication of the reports in 2022/23, the Technical Working Group further reviewed the area while the Regional Planning process was inactive for the region. A new plan that would modify the area supply was agreed as the preferred option and was thus recommended by the TWG.

The recommendation made by the TWG is to provide a new 230kV circuit to the area, upgrade Orleans TS to a 230kV DESN station, and build a new 230kV Hydro Ottawa Municipal Transformer Station. This plan will also allow the retirement of 115kV station Bilberry Creek TS

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which is due for significant sustainment work, including the replacement of both step-down transformers.

This project will address the new 230kV circuit and upgrades at Orleans TS. To provide the new 230kV circuit, Hydro One is planning to make use of the existing H9A conductors on the D5A/H9A towers. These conductors are built for 230kV; however, they operate at 115kV to supply the existing 115kV distribution stations connected to the line. This project will thus connect the H9A conductors at 230kV at Hawthorne TS, and this new 230kV circuit will be labeled A25. To replace the conductors of 115kV circuit H9A, the project will build a 115kV circuit on the existing right of way, between the D5A/H9A towers and A41T/A42T towers, please refer to Figure 1. At Orleans TS, the existing 115kV/27.6kV transformer will be replaced with a 230kV/27.6kV/27.6kV transformer, and this new transformer will be connected to circuit A25, please refer to Figure 2.

This plan addresses several needs for the region and provides the following benefits:

- Address the limited growth available on the 115kV due to the 230kV/115kV 250MVA autotransformer loading at Hawthorne TS and Merivale TS. By moving load from the 115kV to the 230kV system, the autotransformer loading is reduced which will help supplying growth at existing 115kV stations which cannot be easily upgraded to 230kV.
- Avoid significant refurbishment work at Bilberry Creek TS, allowing the station to be retired and its load supplied from 230kV. In addition, Bilberry Creek TS has limited growth even if the station is refurbished.
- Orleans TS will no longer be subject to momentary interruptions due to its configuration.
- Allow more growth in the Orleans area with the addition of a new 230kV circuit.

1.3 Connected Customers

The focus of this study is to assess the impact of the proposed project on existing customers connected to Hydro One's transmission system in the electrical vicinity of the project. Hydro Ottawa Limited and Hydro One Distribution are the two transmission connected customers in the electrical vicinity[1].

Station	Customers
Orleans TS	Hydro One Distribution Hydro Ottawa

[1]Only Orleans TS configuration changes as a result of the new circuit. There are several distribution stations connected to 115kV cuircuit H9A, however no impacts are expected at any of these stations and thus they are not listed.

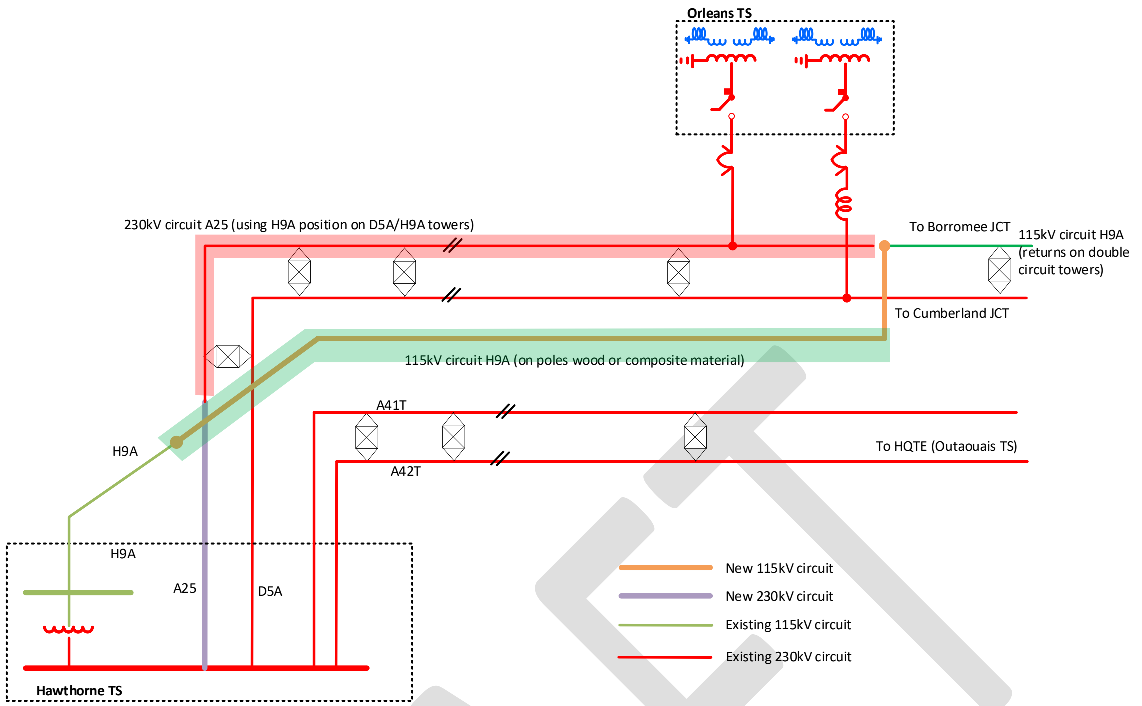

Figure 1.SLD of Hawthorne TS to Orleans TS corridor.

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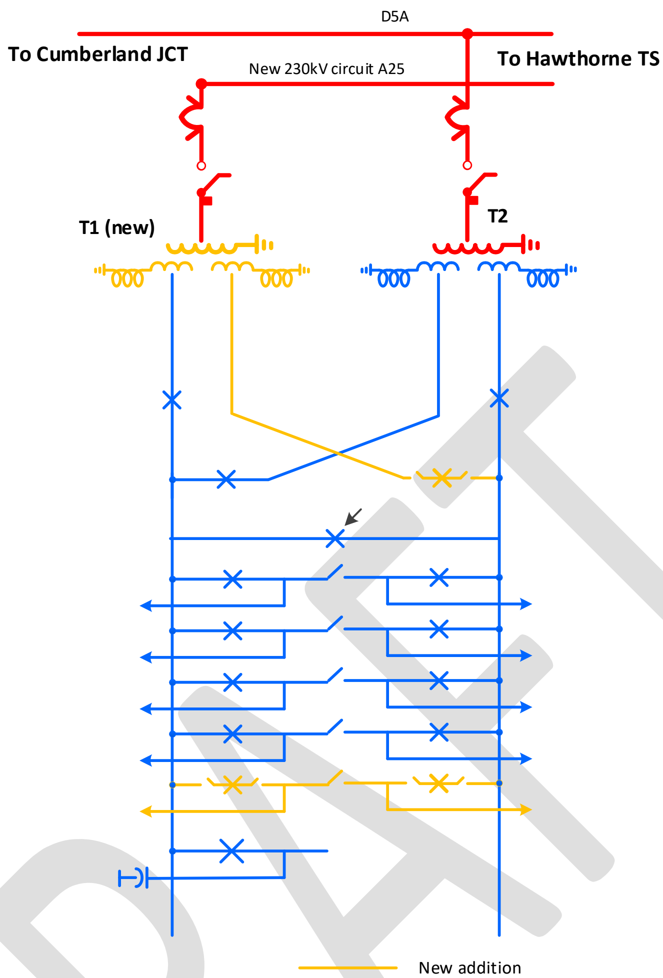

Figure 2. Orleans TS 230kV DESN.

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2.0 LOAD FLOW

The SIA completed by IESO found that the Hawthorne x Orleans upgrade project has no negative impact on the transmission system. Please refer to IESO document CAA ID 2025-834.

The CIA also assessed the area system performance following the completion of the Hawthorne x Orleans for the base case (with all facilities in service) and for one element out of service. All bus voltages are within criteria, and no voltage violations were found for these conditions.

3.0 SHORT- CIRCUIT STUDY

The fault levels for the station of the area are not expected to have any impact as a result of the new 230kV circuit.

The upgrade at Orleans TS will cause an increase in short circuit level at the 27.6kV bus when compared to the existing system, where the station is supplied from the 115kV. This is due to the configuration of Orleans TS, when the station is supplied by the 115kV, only one transformer winding supplies the 27.6kV bus. With the new configuration, each 27.6kV bus will be supplied by two transformer windings, thus increasing the fault level. However, the increase is within the TSC and equipment rating.

4.0 CUSTOMER RELIABILITY

The project is not expected to have a negative impact on the customers of the area. In fact, this project will improve supply reliability to customers supplied by Orleans TS. In addition, the project will also allow for growth in the Orleans area.

5.0 CONCLUSION

This CIA study has reviewed the impact of the Hawthorne x Orleans project on the existing transmission customers connected in the Orleans area. The project is not expected to have any negative effect on the voltages and supply reliability of customers in the area.

Fault levels at buses are in accordance within the Transmission System Code requirement and equipment specifications.

All customers are requested to review the fault levels provided in Appendix A to ensure that the capability of their equipment and grounding system is not exceeded.

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6.0 APPENDIX A

Short circuit level before and after the project is complete.

		Before project				After project				Breaker ratings	
		Sym		Asym		Sym		Asym		Sym	Asym
Station Bus	Voltage	3ph	LG	3ph	LG	3ph	LG	3ph	LG	3ph/LG	3ph/LG
Orleans D5A	250	13.7	12.6	15.1	13.3	13.8	12.7	15.4	13.6	-	-
Orleans A25	250	n/a	n/a	n/a	n/a	12.4	11.4	13.9	12.2	-	-
Orleans J bus	29	12.2	9.8	15.5	12.9	13.5	10.4	16.9	13.4	31.5	37.8
Orleans Q bus	29	7.0	5.3	8.8	6.9	13.2	10.2	16.4	13.2	31.5	37.8

Please note: the short circuit result shown for Orleans Q bus before the project represents the value when the station is supplied from the 115kV system; the J bus value represents the value when the station is supplied from the 230kV.

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REGIONAL AND BULK PLANNING

The Project is driven by regional planning needs, as aforementioned in the Application. The most recent regional planning reports in support of the Project are provided in Attachments 1 to 2, as noted below:

Attachment 1: Ottawa Area IRRP (July 2025)
Attachment 2: Greater Ottawa RIP Report (February 2026)

These reports conclude that the construction of the Project is the preferred option to address the long-term needs in the area and maintain system reliability, consistent with the IESO's evidence in support of need provided in **Exhibit B, Tab 3, Schedule 1, Attachment 1**.

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OTTAWA AREA INTEGRATED REGIONAL RESOURCE PLAN

Ottawa Area Integrated Regional Resource Plan

July 31, 2025

Disclaimer

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List of Acronyms

Acronym	Definition
APO	Annual Planning Outlook
BESS	Battery Energy Storage System
DER	Distributed Energy Resource
DESN	Dual Element Spot Network
DG	Distributed Generation
DR	Demand Response
DS	Distribution Station
eDSM	Electricity Demand Side Management
EV	Electric Vehicle
FIT	Feed-in-Tariff
GS	Generating Station
IESO	Independent Electricity System Operator
ISD	In-Service Date
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LAPS	Local Achievable Potential Study
LDC	Local Distribution Company
LDV	Light-Duty Vehicles
LMC	Load Meeting Capability
LTR	Limited Time Rating

Acronym	Definition
MTS	Municipal Transformer Station
MVA	Megavolt Ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RAS	Remedial Action Scheme
RIP	Regional Infrastructure Plan
SCADA	Supervisory Control and Data Acquisition
TS	Transformer Station
ULO	Ultra-Low Overnight

Executive Summary

This Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Ottawa Area Sub-Region over a 20-year horizon. Developed by the Independent Electricity System Operator (IESO) in collaboration with Hydro Ottawa Limited (Hydro Ottawa), Hydro One Networks Inc. (Distribution), and Hydro One Networks Inc. (Transmission), the plan outlines recommendations to ensure a reliable and cost-effective electricity supply that can support continued economic development and the City of Ottawa's decarbonization objectives.

The Ottawa Area Sub-Region includes the City of Ottawa and the Village of Casselman, and falls within the traditional territory of the Algonquins of Ontario, Kitigan Zibi Anishinabeg, Pikwakanagan First Nation, and Métis Nation of Ontario Region 5. This plan is part of Ontario's broader regional planning framework, now in its third cycle, and reflects the coordinated input of local distribution companies, transmission asset owners, and regional stakeholders.

The need for this IRRP was confirmed through the Scoping Assessment, which identified the Ottawa Area Sub-Region as requiring regional coordination and consideration of non-wires alternatives. The plan is shaped by the City's electrification and decarbonization targets, customer connection requests, and ongoing engagement with groups such as Invest Ottawa. These drivers signal a broader shift toward city-wide energy transformation, with particularly strong momentum in areas like Kanata-Stittsville.

This IRRP marks a notable evolution in planning by integrating electrification as a core assumption from the outset. Load forecasting was developed in collaboration with Hydro Ottawa and Hydro One Distribution, incorporating multiple scenarios with varying degrees of electrification. The selected reference forecast balances feasibility and risk, and reflects a likely trajectory of sustained load growth, winter-peaking demand, and increased system complexity.

In response, the plan provides a flexible sequence of near-, medium-, and long-term actions designed to manage uncertainty while ensuring the system remains prepared to accommodate growth. It reflects established planning best practices, including ongoing adaptation to evolving conditions. Key near-term investments include new transformer stations, line upgrades, and system reinforcements to address station and system capacity needs, asset replacement, and load security and restoration concerns.

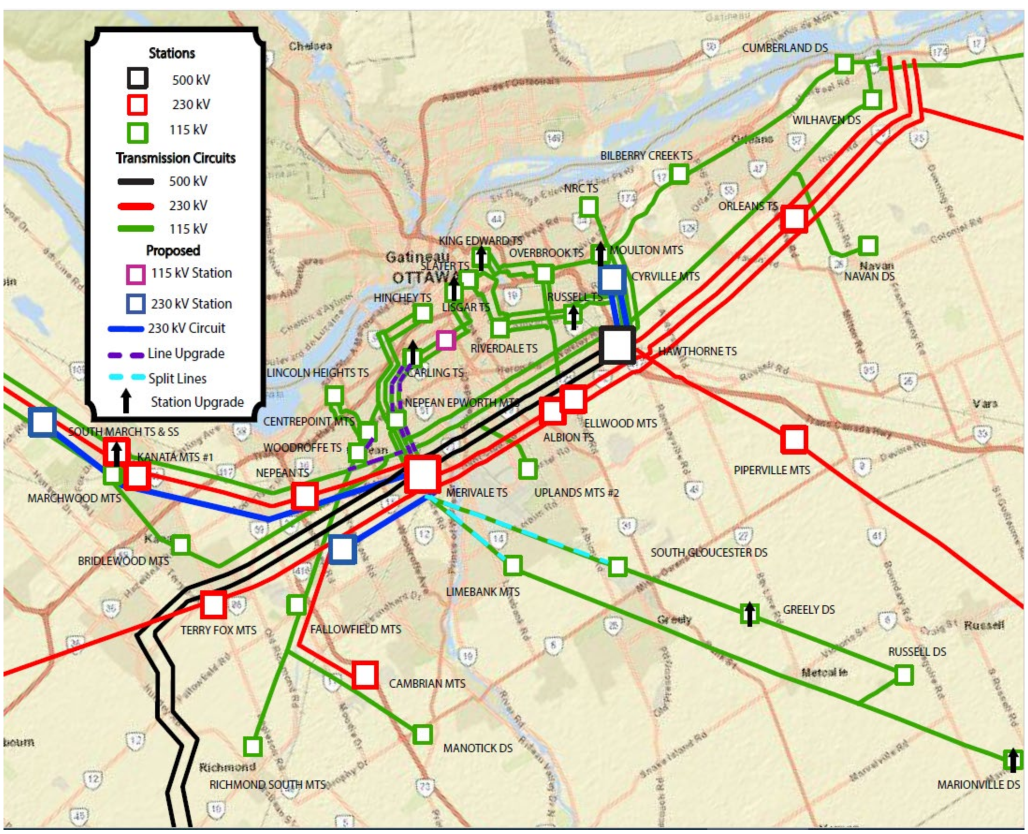
Non-wires solutions play an increasingly important role in the plan. Several large-scale Battery Energy Storage System (BESS) projects identified through the IESO's Long-Term Procurement I (LT1) will enhance reliability, voltage performance, and system resilience. In parallel, the Local Achievable Potential Study (LAPS) will inform targeted demand-side measures that may defer or reduce the need for major infrastructure upgrades, especially in the downtown core.

The recommendations outlined in this IRRP represent a balanced, cost-effective path forward that supports Ottawa's growth while maintaining reliability and customer value. Annual monitoring of load growth and system conditions will inform future updates and help determine when to initiate the next regional planning cycle. A summary of the recommendations can be seen in **Figure 1.**

In summary, the plan proposes to:

- Build new or upgrade Transformation Stations to increase station capacity:
  - Three new 230 kV stations: Kanata North area, Core West area and Cyrville MTS (converted from 115 kV)
  - One new 115 kV station: Core East area (a new MTS by converting from existing distribution station)
  - Station upgrades: Carling TS, Lisgar TS, King Edward TS, Moulton MTS, Russell TS, Greely DS, South March TS and Marionville DS
- Build new or upgrade transmission lines to connect new stations and increase System Capacity:
  - Two new 230 kV transmission lines to connect new stations (Kanata North and Core West areas) from Merivale TS
  - A new 230 kV switching station in Kanata North area
  - 115 kV transmission line uprating: portions of M4G and M5G
- Modify connection configuration to improve load security:
  - Install new circuit breaker at Merivale TS and separate L2M and M1R
  - Provide second supply to Nepean TS via new transmission circuit from Merivale TS.
- Transfer load between stations through the distribution system to balance and optimize the utilization of station capacity
- Integrate the eDSM program opportunities identified as part of LAPS
- Formalize adaptive pathways for each subsystem

Figure 1 | Map of Recommendations for Ottawa Area Sub-Region



1. Introduction

This IRRP documents the recommendations required to address the electricity needs for the Ottawa Area Sub-Region over the next 20 years. It was prepared by the IESO on behalf of a technical working group (Working Group) composed of the IESO, Hydro Ottawa, Hydro One Distribution, and Hydro One Transmission. Hydro Ottawa, a municipally owned utility that operates in the City of Ottawa (City) and in the Village of Casselman, and Hydro One Distribution are local distribution companies (LDCs) that serve customers in the sub-region. Hydro One is the transmission asset owner in the sub-region.

This sub-region also includes the following First Nations and Métis Nation of Ontario councils:

- Algonquins of Ontario
- Kitigan Zibi Anishinabeg
- Pikwakanagan First Nation
- Métis Nation of Ontario Region 5

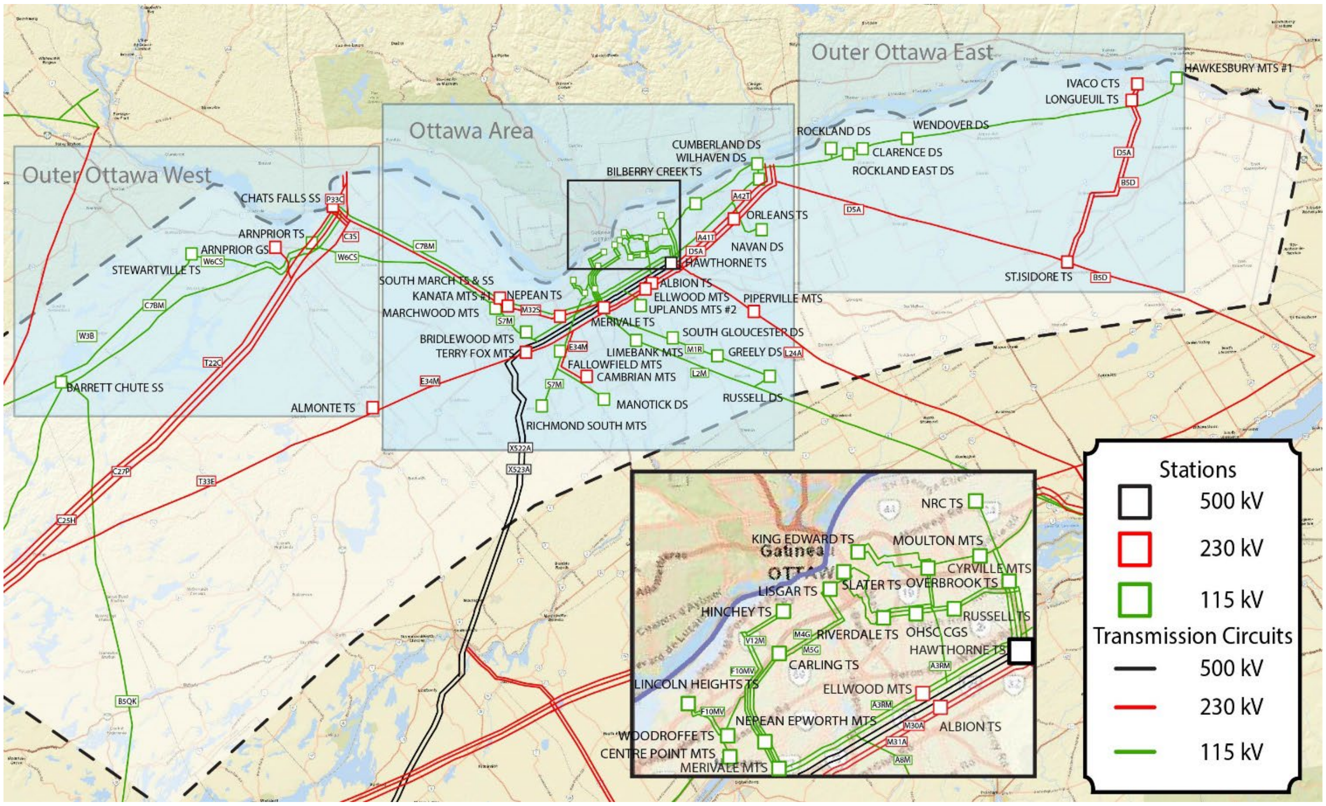
In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is carried out through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributers, and the IESO are required to carry out regional planning activities for 21 electricity planning regions across Ontario, at least once every five years. This is the third cycle of regional electricity planning, which resulted in the third IRRP for the Ottawa region.

For the purposes of regional planning, the Ottawa region has historically been subdivided into three major sub-regions, as shown in **Figure 2**. One of the main purposes of an IRRP is to foster collaboration where coordination between multiple stakeholders in a region is required. Hydro Ottawa is the main LDC that serves the electricity demand for the City of Ottawa. Hydro One Distribution supplies load in the surrounding areas of the sub-region. Both Hydro Ottawa and Hydro One Distribution receive power at the step-down transformer stations (TS) and distribute it to end users, including industrial, commercial, and residential customers.

The Scoping Assessment confirmed the need for regional coordination and the importance of evaluating non-wires alternatives to address emerging electricity needs. As a result, the Working Group determined that this IRRP will focus on the Ottawa Area Sub-Region, while the remaining sub-regions will be addressed through the Regional Infrastructure Plan (RIP) led by Hydro One Transmission as those sub-regions are predominantly served by Hydro One Distribution.

The Ottawa Area Sub-Region encompasses the City, including the Kanata, Nepean, and Orléans communities. To further simplify the organization and analysis, the Working Group further divided the sub-region into four subsystems based on their geographic and electrical characteristics. The four subsystems can be seen in **Figure 3** and this report will address each subsystem separately throughout. A more thorough description of each of the subsystems can be found in Section 4 (background) and Section 6 (needs).

Figure 2 | Overview of the Greater Ottawa Sub-Regions

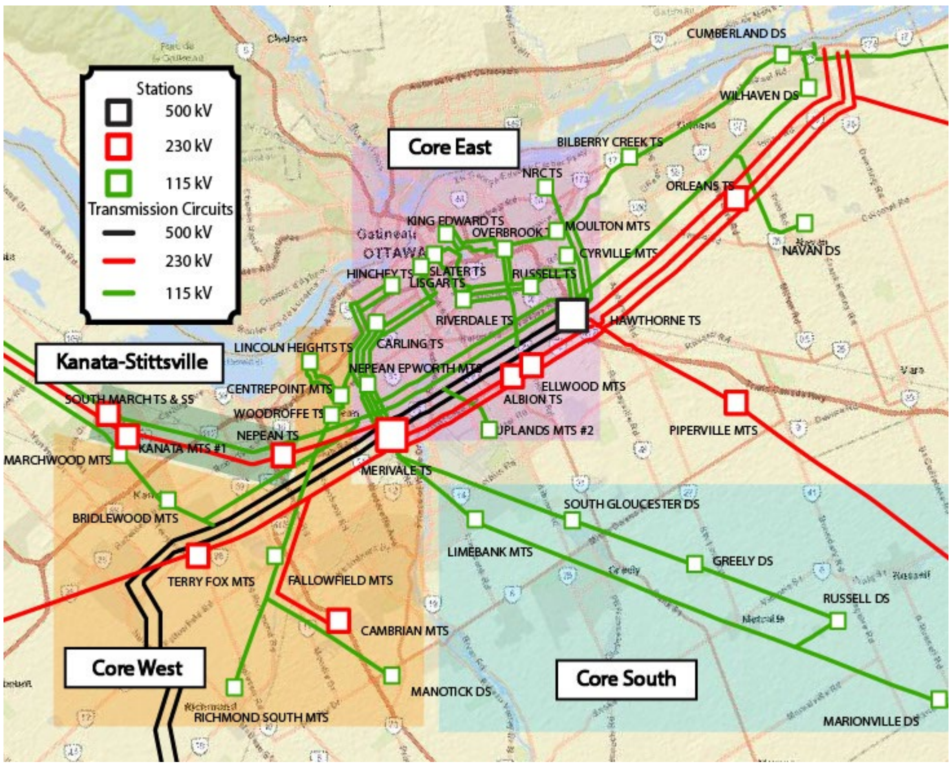


Every plan faces its own unique challenges, and this third cycle of regional planning for the Ottawa area is no exception. The City of Ottawa and the federal government have set ambitious decarbonization and electrification goals, which serve as a foundational input to this IRRP. These goals, supported by customer connection requests, projected growth trends, and consultations with economic sector participants such as Invest Ottawa, reflect a broader shift toward city-wide economic transformation — with particular momentum in areas like Kanata-Stittsville. While previous regional plans included electrification among several scenarios, this IRRP distinguishes itself by embedding electrification as a core planning assumption from the outset, recognizing both the uncertainty it introduces and the opportunity to plan proactively to meet emerging system demands.

The Working Group convened a series of discussions with the City and various energy stakeholders during the development of the plan, aiming to collaboratively shape the demand forecast and align on anticipated decarbonization trends. These conversations helped inform the demand forecasts developed by Hydro Ottawa and Hydro One Distribution. Several scenarios were developed with varying degrees of electrification. By balancing risk and feasibility, one of these scenarios was selected as the reference demand forecast that drove the needs, options, and recommendations found in this report. A high-growth scenario was also identified for sensitivity analysis.

The forecasted economic development, decarbonization, and electrification would result in a substantial increase in peak electricity demand over the next 20 years. Furthermore, the forecast indicates that the region will soon become winter-peaking, due in large part to the effects of transitioning heating from natural gas to electric or hybrid. This ultimately led to the identification of numerous needs in the sub-region that span the near-, medium-, and long -terms which refer to outlooks in the 5-, 10-, and 20-year horizons respectively.

Figure 3 | Overview of the Four Ottawa Area Subsystems



Anticipated electricity demand growth in Ottawa presents a planning challenge: ensuring the system is positioned to support organic growth and economic development, while avoiding the premature construction of assets that may not be needed in the near term. Missed opportunities to enable new connections or achieve the City's decarbonization targets could have lasting impacts. At the same time, overbuilding infrastructure too far in advance could result in unnecessary costs to electricity customers.

To manage these risks, this plan takes a flexible and phased approach — one that reflects good planning practice and builds on how the electricity sector in Ontario has adapted to uncertainty over time. This IRRP outlines a sequence of actions that can evolve as conditions change, providing a framework to respond to growth while managing uncertainty responsibly.

Multiple BESS projects in the sub-region have been recommended through the IESO's LT1 initiative. Once developed, these large-scale batteries will help improve voltage performance, enhance reliability, and provide added flexibility and resilience to the grid.

In addition, a LAPS is expected to inform targeted conservation and demand management opportunities. These measures may help defer large, costly upgrades — particularly in the downtown core — by reducing strain on existing infrastructure.

The firm recommendations in this IRRP are designed to address near-term system and station capacity needs, asset replacement requirements, and load security and restoration needs, while laying the groundwork for longer-term improvements. Annual monitoring of potential issues will provide additional input on when the next regional planning cycle should be initiated.

This report is organized as follows:

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

2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Ottawa Area Sub-Region over the next 20 years. The identified needs are based on the demand growth anticipated in the region and the capability of the existing transmission system, as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC). The IRRP's recommendations are informed by an evaluation of different options to meet the needs and consider reliability, cost, technical feasibility, and maximizing the use of the existing electricity system (where economically feasible). The plan also reflects feedback from stakeholders and seeks to balance the need to ensure the system is poised to enable growth — including economic development — with the risk of building investments too early.

The Ottawa Area Sub-Region electricity demand forecast, provided by the LDCs, projects sustained growth driven by municipal growth, commercial development, and the effects of electrification and decarbonization. The planned phase-out of gas heating in the region is also a major driver of the demand forecast and electricity supply needs in the sub-region, especially in later years of the demand forecast.

The IRRP recommendations are organized into a near-term plan and a set of ongoing or medium- to long-term initiatives. This structure reflects the varying degrees of forecast certainty, development lead times, and planning commitments required over different timeframes. By doing so, the IRRP offers clear guidance on immediate investment needs while maintaining flexibility to adapt over the medium and long term as electrification, energy efficiency, and development plans continue to evolve.

2.1 Near-Term Plan

The near-term plan consists of several recommendations to accommodate load growth, maintain reliability, and optimize asset replacement. Many of these needs are driven by the strong growth in the winter demand forecast. The major recommendations are summarized in **Table 1**.

Table 1 | Summary of Recommendations

Need Type	Affected Element(s)	Recommendation	High Level Planning Cost Estimate[1]
System Capacity (Transformation, Voltage Stability)	Kanata-Stittsville	Build new 230kV Transformer Station north of existing stations. Connect to C3S and new transmission line from Merivale TS. Interim station name: Kanata North Municipal Transformer Station (MTS).	$45M
		Build new 230kV transmission line from Merivale TS by rebuilding C7BM corridor, connecting Nepean TS and new Kanata North MTS	$185M
		Build a switching station that connects existing and new 230kV stations to improve resiliency and flexibility	$65M
System Capacity (Transformation)	Core East	Build new 115kV Transformer Station by converting existing distribution station. Connect to M4G and M5G. Interim station name: Bronson MTS.	$65M
System Capacity (Thermal Overload)	Core East	Upgrade portions of existing 115kV circuits M5G and M4G.	$35M
System Capacity (Transformation)	Core East	Convert Cyrville MTS (115kV) to 230kV thereby preserving capacity on autotransformers for growth on the 115kV downtown system	$75M
		Pursue eDSM program opportunities identified as part of LAPS to reduce demand and delay large scale infrastructure upgrades.	N/A

[1] All cost estimates are capital cost values

Need Type	Affected Element(s)	Recommendation	High Level Planning Cost Estimate[1]
System Capacity (Transformation)	Core West	Build new Transformer Station to meet demand growth and need for 28kV supply west of Merivale TS. Interim station name: Greenbank MTS.	$40M
		Build new 230kV transmission line from Merivale TS to supply new Greenbank MTS.	$50M
Load Security	Core South	Install new circuit breaker at Merivale TS and separate L2M and M1R	$30M
Planning	N/A	Working Group to produce Adaptive Pathways documents for each subsystem following the publishing of the IRRP. Utilize Annual Working Group meeting to refine and communicate the pathways to relevant stakeholders.	

A complete list of recommendations can be found in Section 7.8.

A high-level planning estimate based on 2025 capital costs for the proposed suite of solutions is approximately $900 million, with a recommended In-Service Date (ISD) ranging between 2029-2032, based on the growth forecast. The identified needs have been grouped to align with integrated solution sets, as outlined in Section 6 of this report. The recommendations from this report will be further prioritized during the RIP. The near-term recommendations represent critical first steps in expanding the electricity grid's capabilities to support the region's goals in a timely manner.

2.2 Medium-, to Long-Term Plan

While most of the recommended actions from the Ottawa Area Sub-Region IRRP are planned for the near-term (within the next five years), the sections below outline potential medium- to long-term recommendations beyond that horizon. The actions described below illustrate the adaptive pathways identified through this regional planning process. These pathways are subject to change and will be continuously re-evaluated as planning progresses, based on new information and actual load growth. Awareness of these plans is important to enable timely decision-making. Further details on the adaptive pathways, including the subway-style maps, are provided in Section 7. It is recommended that the Working Group finalize the long-term adaptive pathway plan for each subsystem following the completion of this cycle of regional planning.

Kanata-Stittsville Subsystem

To address the significant capacity needs at Kanata MTS, South March TS and, eventually, Nepean TS a new switching station is planned to interconnect these key sites. This switching station will provide critical resiliency, operational flexibility, and expandability for future load growth. Additionally, the station will serve as a hub for a new transmission line extending north to Chats Falls TS, pending upgrades at Chats Falls to support the connection. This project will not only diversify supply paths and increase the Load Meeting Capability (LMC) for the area, but also improve Ottawa's overall system strength.

The East Bulk Study, currently underway, is exploring potential reinforcements to strengthen the supply path into Ottawa. As part of this, the proposed switching station is being evaluated for its potential to support the expansion of the 230 kV network. In addition to enhancing regional integration, this connection would diversify supply sources and improve the overall resilience of the electricity system in the Ottawa area.

Core East Subsystem

Core East faces the most acute and widespread capacity challenges, particularly in the 115 kV downtown network. Due to physical constraints on system expansion, eDSM program opportunities identified in the LAPS could play a crucial role in regulating and managing downtown load growth. Long-term planning includes expanding Hawthorne TS, extending a mix of 115 kV and 230 kV circuits into the downtown core, and constructing additional supply stations to relieve pressure on aging infrastructure. A fourth autotransformer at Merivale TS is also under consideration, which would enhance transfer capability and reduce strain on nearby stations. To further alleviate pressure on the 115 kV system, a planned conversion of S7M will allow additional load to be shifted off the constrained network.

Core West Subsystem

With station overloads emerging across Marchwood, Fallowfield, Manordale, and others, the long-term strategy for Core West centres on the conversion of circuit S7M to 230 kV. This will relieve the 115 kV system, preserving capacity for downtown load growth while supporting suburban development. The new circuit can be extended to provide a second supply path to Terry Fox MTS and Cambrian MTS, enhancing reliability and operational flexibility. This conversion will also unlock the full potential of a large-scale BESS identified in the LT1 framework. Additional transmission work, including uprating portions of C7BM and F10MV, is planned to mitigate thermal overloads and enhance backbone performance.

Core South Subsystem

Future planning in Core South hinges on the findings of the East Bulk Study, with a possible 230 kV transmission line from the St. Lawrence area offering the potential to fully convert the pocket to 230 kV operation. Limebank MTS, forecast to exceed capacity in the medium term, will require a second supply path as load grows; monitoring and proactive circuit upgrades will be key. A new autotransformer station in western Ottawa is also under consideration, and its implementation will influence future planning and routing decisions for Core South.

3. Development of the Plan

3.1 The Regional Planning Process

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

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

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

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

3.2 Ottawa Area Sub-Region IRRP Development

The process to develop the Ottawa Area Sub-Region IRRP started in March 2023, following the publication of the **Needs Assessment Report** in December 2022 by Hydro One and the **Scoping Assessment Outcome Report** in February 2023 by the IESO. The Scoping Assessment recommended that the needs identified for the Ottawa Area Sub-Region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region.

Given the significant uncertainty surrounding the impacts of electrification and decarbonization, the Working Group has taken several important steps to manage this risk. Recognizing Ottawa's unique combination of rapid urban growth, economic development opportunities, and decarbonization initiatives, it was clear that a flexible and forward-looking approach was necessary. As a first step, the LDC engaged a third-party consultant to develop a series of load forecast scenarios that incorporated full decarbonization by 2050. This process ensured that the forecasts accounted for electrification in a meaningful way and were developed with a high degree of objectivity and technical rigour. The resulting scenarios highlighted the challenge of managing substantial load growth over a relatively short period of time, which further reinforced the need for a more flexible planning approach.

The Working Group remains committed to ongoing monitoring of actual load growth, technological developments, and policy changes, ensuring the plan continues to reflect real-world conditions. This approach reflects a foundational aspect of electricity planning in Ontario — the recognition that flexibility and regular updates are essential in the face of evolving system needs. The adaptive approach outlined in this IRRP provides a structured yet flexible roadmap that enables the electricity system to grow in step with Ottawa's evolving demand, while maintaining reliability, cost-effectiveness, and resilience. It also aligns with the City of Ottawa's direction on electrification and supports local aspirations related to the energy transition.

4. Background and Study Scope

4.1 Previous Regional Planning Cycle

This is the third cycle of regional planning for the Ottawa Area Sub-Region. The previous cycle of regional planning for the Ottawa Area Sub-Region was carried out from 2018 to 2020 and resulted in the publishing of an IRRP and an RIP. Furthermore, between-cycle planning occurred in 2022 to revisit a previous recommendation for the Orléans area. The Working Group reconvened and decided not to refurbish Billberry Creek as previously recommended and will instead decommission the station and focus on new infrastructure in the Orleans area. The recommendations are described within the report.

The previous Ottawa Area Sub-Region IRRP was published in March 2020. The IRRP used a 20-year demand forecast and made recommendations to monitor long-term needs in the region, while providing clear direction on actions required in the near-term. This included several distribution load transfers and asset replacements as described below. Furthermore, the plan recognized the need for a long-term solution for the Kanata-Stittsville area but decided that interim measures in the forms of enhanced IESO led energy efficiency programs were more prudent at that stage. This plan picks up where the previous plan left off and provides the next steps for expanding the electricity system to meet growing demand.

The plan also identified two supply deficiencies in the southwest and southeast areas of the Ottawa Area Sub-Region. In the southwest, referred to as the Core West subsystem in this report, the Cambrian MTS station was brought into service in 2022. Originally identified in 2008 and approved by the IESO in 2016, this new station addresses growing demand in the area. In the southeast, a new station, Piperville MTS, is currently under construction. This station will relieve neighbouring stations and provide additional capacity to support emerging load growth in the region.

Additionally, to accommodate both load growth and the end-of-life considerations in the Orléans area, it is recommended that the Billberry Creek station be decommissioned. In its place, a new station—tentatively named Mer-Bleue MTS—will be required to serve the existing load, with an expected in-service date of 2027. Finally, the introduction of a new electrified municipal bus fleet will necessitate the construction of a bus charging station near Hawthorne TS, referred to as Hydro Road MTS in the current plan

2020 Ottawa Integrated Regional Resource Plan Recommendations

- Hydro Ottawa is to implement the North Kanata Retrofit Top-Up Program and the North Kanata Smart Thermostat Program, which are targeted commercial and residential energy efficiency programs. Hydro Ottawa is also planning distribution system transfers to reduce demand at heavily loaded stations.
- Hydro One is to replace Merivale TS Transformer T22 with one that is equivalent to T21.
- Hydro One is to proceed with the like-for-like refurbishment of Bilberry Creek TS, which is approaching its end-of-life, and expand the station to accommodate two additional breaker positions to supply Hydro Ottawa customers.

- Hydro One is to replace Slater TS T2 and T3, which are approaching their end-of-life, with larger transformers, approximately 100 megavolt amperes (MVA), as was done for the recent replacement of T1.
- Hydro One is to replace the two 75 MVA transformers at Albion TS, which are approaching their end-of-life, with similar size transformers.
- Hydro One is to replace the two 75 MVA transformers at Lincoln Heights TS, which are approaching their end-of-life, with similar size transformers.
- Hydro Ottawa is to plan and seek approval for a new 230 kV connected supply station in southeast Ottawa.

2020 Ottawa Regional Infrastructure Plan Recommendations

- Replace end-of-life transformers T1/T2 at Lincoln Heights TS: complete in 2024, 2023 respectively (45/60/75 MVA).
- Replace end-of-life transformers T3/T4 at Longueuil TS: in-service date of 2025.
- Replace end-of-life 115 kV breakers at Riverdale TS: In-service date of 2028.
- Increase transformation capacity in southeast Ottawa, with Hydro Ottawa building a transformer station: station named Piperville TS, expected in-service date 2026.
- Replace end-of-life transformers T1/T2 and circuit breakers at Albion TS.
- Replace end-of-life transformers at Russel TS.
- Determine limitation of low voltage-cables, upgrade cables at Overbrook TS: station Limited Time Rating (LTR) increased between cycles, which reflects this change.
- Upgrade Hawkesbury MTS station capacity.
- Refurbish Bilberry Creek TS end-of-life: the Working Group recommends decommissioning Billberry Creek in favour of new DESN, as described within the report.
- Replace T22 at Merivale TS: this project is ongoing and is part of the Merivale project, which is in service in 2029
- Voltage performance of 79M1 evaluated as part of next IRRP: moving to 2025 RIP

4.2 Bulk Planning and Other Developments

Beyond historical regional planning efforts, the Ottawa Area Sub-Region has also been the focus of bulk planning initiatives and other key developments.

2022 Gatineau Corridor Study

- Refurbish all 800 km of 230 kV circuits on the Gatineau Corridor identified as nearing end-of-life.
- Build a new double-circuit 230 kV transmission line into Dobbin TS (in Peterborough) from Clarington TS (in Oshawa), with a planned in-service date of 2029.

- Pursue up to 230 megawatts (MW) of additional system cost-effective energy efficiency in the Ottawa area over the 20-year planning horizon, while monitoring demand growth and resource acquisition activities in the Ottawa zone.
- Update and expand the use of remedial action schemes (RASs) in the Peterborough and Ottawa areas to meet planning standards and further improve the load meeting capabilities of both areas.
- Implementation of recommendations is ongoing.

2023 Orléans Area Study

To manage forecast risks from high electrification growth, maintain reliability, and defer major upgrades to Ottawa's 115 kV system beyond the third autotransformer at Merivale TS, an integrated solution package is recommended. This includes decommissioning Bilberry Creek TS, building a new 230 kV circuit from Hawthorne TS to Orléans TS, and upgrading Orléans TS to a 230 kV DESN.

IESO Long-Term 1 Procurement

During the IRRP process, the IESO launched its Long-Term 1 Procurement, which has led to competitive pricing for new resources, municipal support, and significant Indigenous participation and equity ownership in projects. The IESO entered into contracts with 13 selected proponents, securing approximately 2,200 MW of new capacity, set to come online between 2026 and 2028. Among these procurements are two large-scale BESS located in the Kanata-Stittsville and Core West subsystems to the west of Ottawa.

Although the IRRP evaluated batteries as part of the non-wires solutions process and found that they could not fully address the identified needs on their own, they offer valuable benefits, including improvements in voltage stability, peak demand management, and enhanced system reliability. This plan supports the technical advantages of these projects and acknowledges that a diversified system will be crucial for realizing the long-term vision of the electricity landscape.

Eastern Ontario Bulk Plan

- The IESO is carrying out an Eastern Ontario Bulk Study to assess the sufficiency of the bulk transmission system to reliably supply the demand growth expected in Greater Ottawa areas. The bulk plan will be coordinating with this IRRP regarding demand forecast and regional assumptions to ensure alignment and efficiency.
- The targeted completion of this bulk plan is Q1 2026.

4.3 Current Cycle of Regional Planning

The current cycle of regional planning began in 2023 with the publication of the Needs Assessment Report, where several needs requiring further regional coordination were identified. The 2023 Ottawa Scoping Assessment recommended an IRRP for the Ottawa Area Sub-Region to address needs in a coordinated manner. This report presents an integrated regional electricity plan for the next 20-year period starting from 2024.

This IRRP develops and recommends options to meet the electricity needs of the Ottawa Area Sub-Region in the near-, medium-, and long-term. The plan was prepared by the IESO on behalf of the

Working Group, and considers forecast electricity demand growth, eDSM, distributed generation (DG), transmission and distribution system capability, relevant community plans, condition of transmission assets, and developments on the bulk transmission system.

The transmission facilities included in the scope of this study are shown in **Table 2**, **Table 3**, and **Table 4**:

Table 2 | Transformer Stations

Albion TS	Bridlewood MTS	Cambrian MTS	Carling TS
Centrepoint MTS	Cumberland DS	Cyrville MTS	Ellwood MTS
Fallowfield MTS	Greely DS	Hawthorne TS	Hinchey TS
Kanata MTS	King Edward TS	Limebank MTS	Lincoln Heights TS
Lisgar TS	Manordale MTS	Manotick DS	Marchwood MTS
Marionville DS	Merivale MTS	Moulton MTS	National Aeronautical CTS
National Research Council CTS	Navan DS	Nepean Epworth MTS	Nepean TS
Piperville MTS	Orléans TS	Overbrook TS	Richmond South MTS
Riverdale TS	Russell DS	Russell TS	Slater TS
South Gloucester DS	South March TS	Terry Fox MTS	Uplands MTS
Wilhaven DS	Woodroffe TS	Hydro Road MTS	

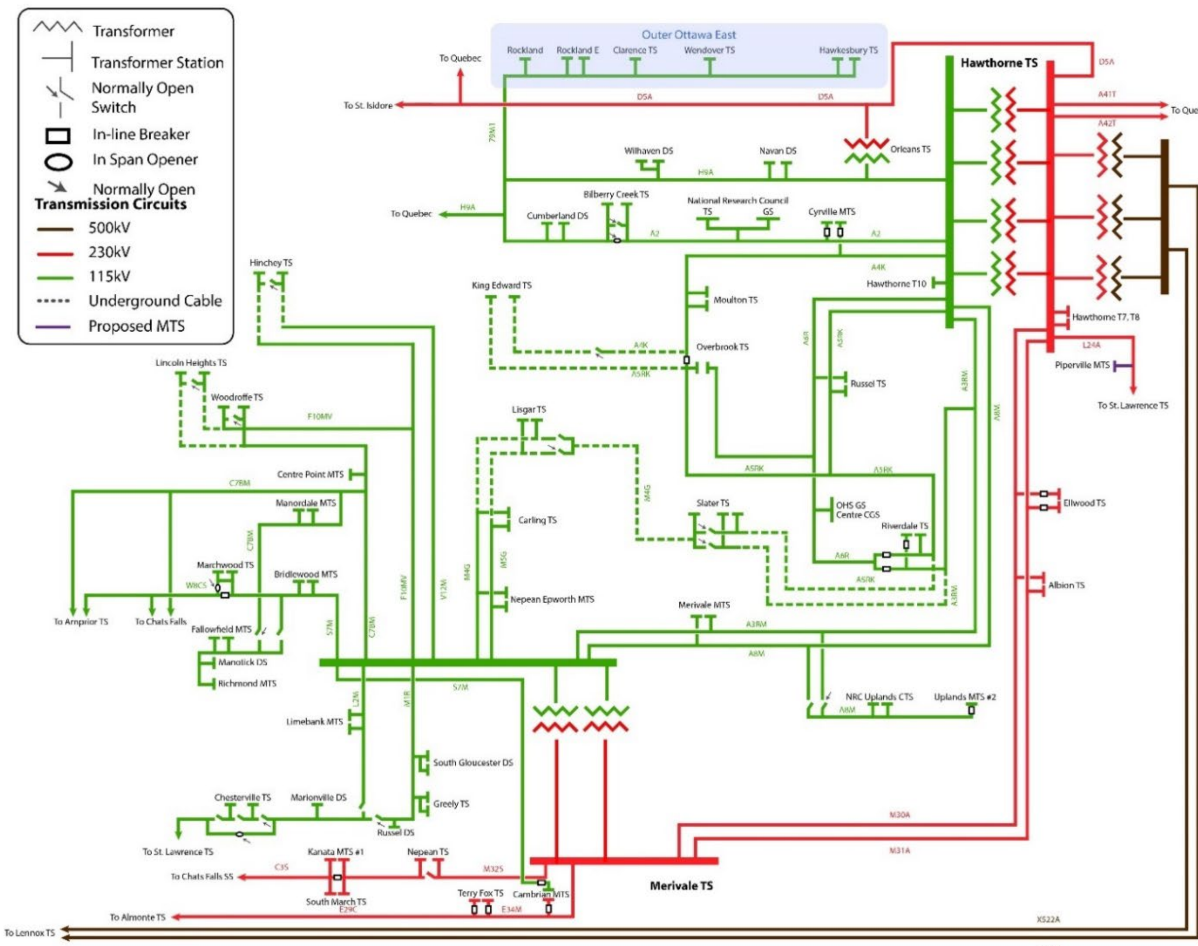
Table 3 | 115 kV Transmission Circuits

C7BM	F10MV	V12M	S7M	W6CS	A5RK
A4K	A6R	A8M	A3RM	A2	H9A
M1R	L2M	M4G	M5G		

Table 4 | 230 kV Transmission Circuits

E34M	D5A	L24A	B5D	M30A	M31A
M32S	C3S	L24A			

Figure 4 | Single Line Diagram of the Ottawa Area Sub-Region



The single line diagram of the Ottawa Area Sub-Region is shown in **Figure 4**. Note that the bulk system transfer capabilities on the Flow-into-Ottawa (FIO) interface into the region is not within the scope of this IRRP and was separately studied in the East bulk transmission plan. The schedule of bulk planning activities is identified through the IESO's **Annual Planning Outlook**.

Ottawa is a major load centre in eastern Ontario, which is primarily supplied by:

- two 500 kV circuits from Lennox TS in Lennox and Addington County
- two 230 kV circuits from St. Lawrence TS in Cornwall
- one 230 kV circuit from Chats Falls SS
- one 115 kV circuit from Barrett Chute GS
- one 115 kV circuit from Stewartville GS
- an inter-connection with Quebec's transmission system at Hawthorne TS, located in the east side of Ottawa

The transmission system serving Ottawa has several interfaces that can limit the ability to meet demand within the city and efficiently transfer power from generation and imports in eastern Ontario across the provincial grid. Ottawa's electricity needs are primarily met by a series of 230 kV and 115 kV transmission circuits that emanate from the Merivale TS and Hawthorne TS stations, which serve as the central hubs for the city's power supply.

Historically, Ottawa experiences peak demand during the summer, with loads reaching approximately 1,600–1,700 MW. However, over the next 20 years, demand is expected to grow significantly, and the region is forecast to transition into a winter-peaking area as early as 2030. There is minimal internal generation capacity in Ottawa, with only one transmission-connected generator—a 70 MW combined-cycle gas plant. In addition, there are several distribution-connected generators within the city, with the most notable being the Chaudière Falls hydroelectric plants, which collectively contribute around 90 MW of capacity

The Ottawa IRRP was developed by completing the following steps:

1. Preparing a 20-year electricity demand forecast and establishing needs over this timeframe.
    a. Examining the LMC and reliability of the existing transmission system, considering facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC criteria.
    b. Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid.
    c. Confirming identified asset replacement needs and timing with the transmitter and LDCs.
2. Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches, such as non-wires alternatives including eDSM.
3. Engaging with the community on needs and possible alternatives.
    a. Evaluating alternatives to address near- and long-term needs.
    b. Considering the impact of the high forecast as a sensitivity of the flexibility and optionality of the potential alternatives.
4. Communicating findings, conclusions, and recommendations within a detailed plan.

5. Electricity Demand Forecast

Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in a region. This section describes the development of the demand forecast for the Ottawa Area Sub-Region. It highlights the assumptions made for peak demand forecasts, including weather correction, the contribution of eDSM and DG, and the development of a high-growth scenario. The reference net extreme weather demand forecast is used in assessing the electricity needs of the area over the planning horizon; the high forecast scenario, used as the basis for a sensitivity analysis, is described further in Section 5.6.2.

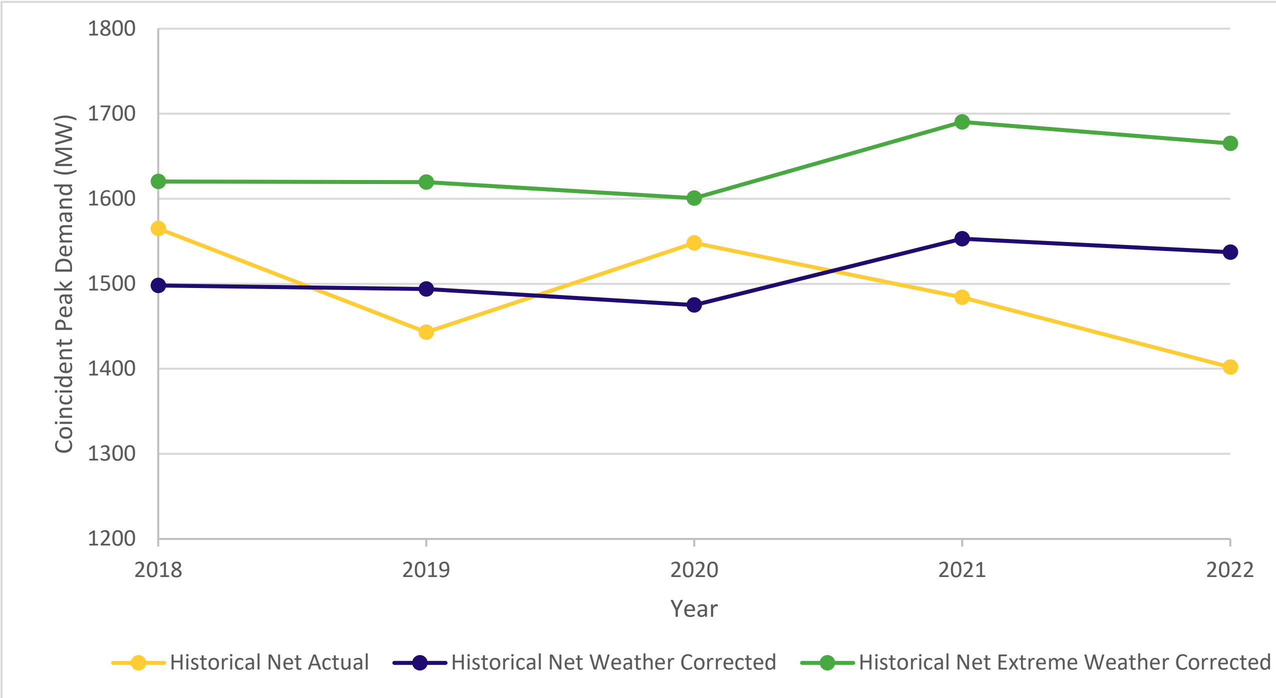
To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Within the Ottawa Area Sub-Region, the peak loading hour for each year has historically occurred in the summer. However, with the recent and projected growth of electric heating, the region is projected to become winter-peaking.

5.1 Historical Demand

Summer peak electricity demand within the Ottawa Area Sub-Region has remained stable in the five years prior to this planning cycle. **Figure 5** shows the coincident net actual (as observed at the metering point), net median weather-corrected (adjusted to reflect median weather conditions), and net extreme weather-corrected (adjusted to reflect extreme weather conditions) historical demand. The summer net median weather-corrected demand has averaged 1,500 MW over the past five years, with the peak demand hour for each year occurring between approximately 3 PM to 5 PM.

Since the forecast was developed in 2023, only the 2022 values were available to create gross starting points. The starting points used the median weather corrected 2022 values, adding the effect of DG to make it a gross weather-corrected starting point.

Figure 5 | Historical Peak Demand in the Ottawa Area Sub-Region

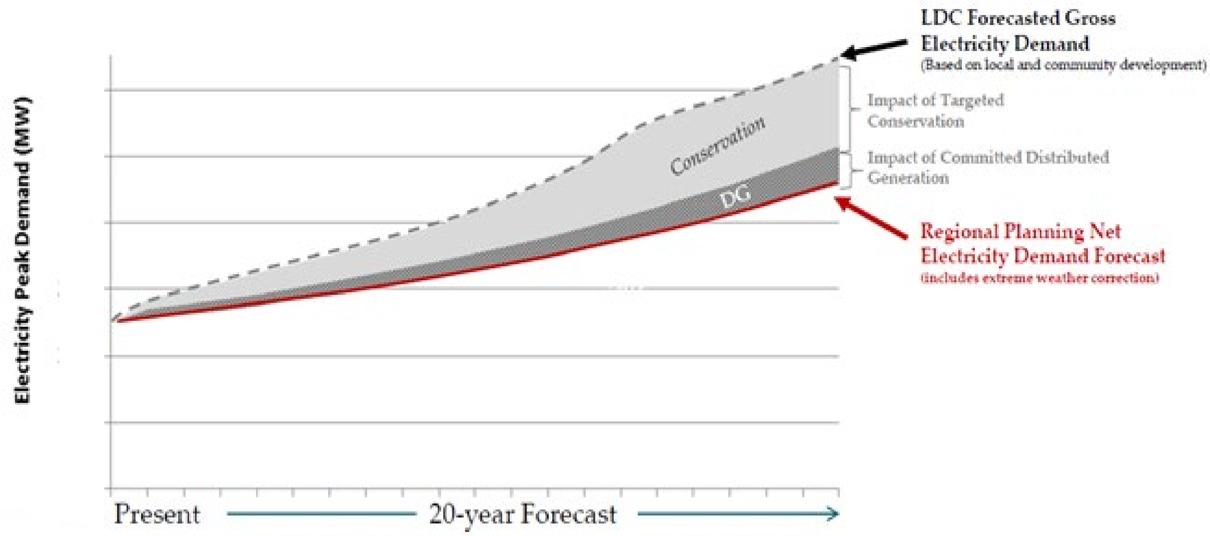


5.2 Demand Forecast Methodology

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

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

Figure 6 | Illustrative Development of Demand Forecast



5.3 Gross LDC Forecasts

Each participating LDC in the Ottawa Area Sub-Region prepared gross demand forecasts at the station level. These gross demand forecasts account for increases in demand from new or intensified development, plus known connection applications. The LDCs cited alignment with municipal and regional official plans and credited them as a source for input data. LDCs were also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices ("natural conservation"), but not for the impact of future DG or new conservation measures (such as codes and standards and eDSM programs), which are accounted for by the IESO (discussed in Section 5.45).

The gross LDC forecasts assume median on-peak weather conditions and loading that is coincident to each station. A coincident demand forecast was used instead of a non-coincident forecast because it better reflects the system-level peak, which is critical for planning shared infrastructure. While some individual stations may experience higher non-coincident peaks, these are typically captured in the winter forecast, which drives most station capacity needs. However, this approach can introduce some uncertainty, particularly for the winter period, and may understate summer needs in some areas—potentially shifting the summer need date slightly later.

LDCs have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with the customers, connection applicants, and municipalities and communities that they serve. The IESO typically carries out demand forecasting at the provincial level. More details on LDC load forecast assumptions can be found in Appendix B.2 to B.6. **Figure 7** and **Figure 8** show the total reference and high-growth gross coincident demand forecasts provided by the LDCs for the Ottawa Area Sub-Region.

Hydro Ottawa worked closely with Enbridge Inc. to develop electrification scenarios dealing with the transition from natural gas to heat-pump based electrical heating. A full breakdown of each LDC's methodology can be found in the Appendix B and on the IESO's Ottawa engagement webpage.

Figure 7 | Total Summer Gross Coincident Demand Forecasts Provided by LDCs (Median Weather)

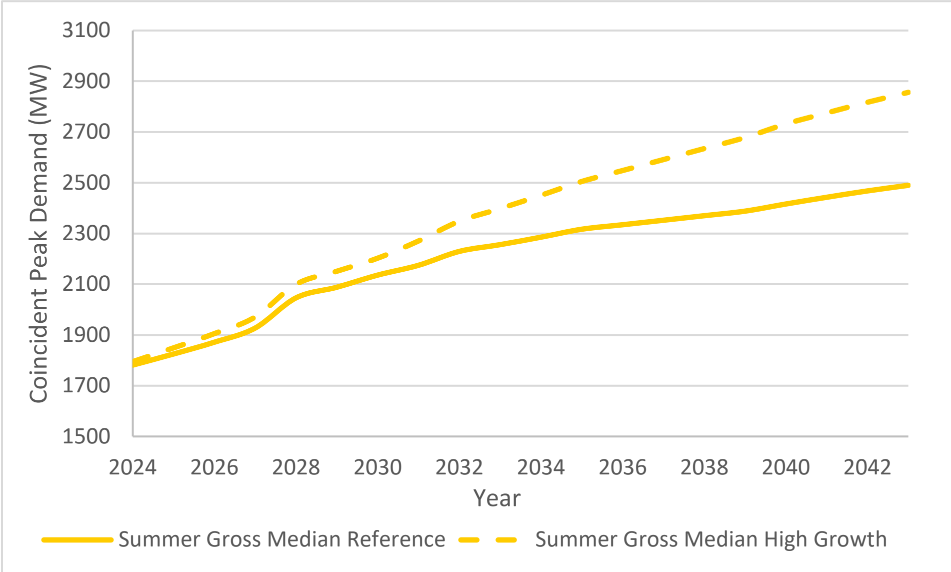
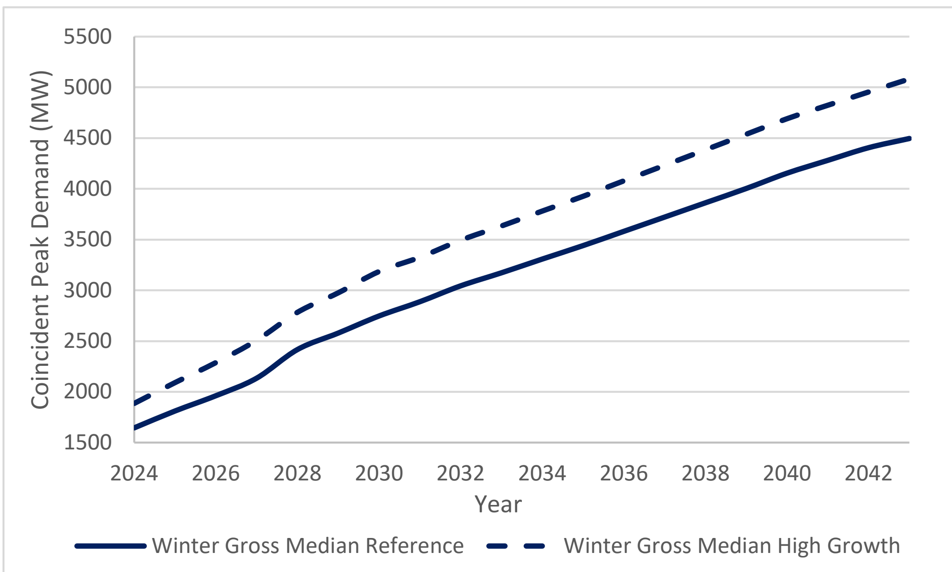


Figure 8 | Total Winter Gross Coincident Demand Forecasts Provided by LDCs (Median Weather)



5.4 Contribution of eDSM to the Forecast

Electricity Demand Side Management is a clean and cost-effective resource that helps meet Ontario's electricity needs and has been an integral component of provincial and regional planning. eDSM is achieved through both codes and standards amendments, as well as eDSM incentive program-related activities. These approaches complement each other to maximize results.

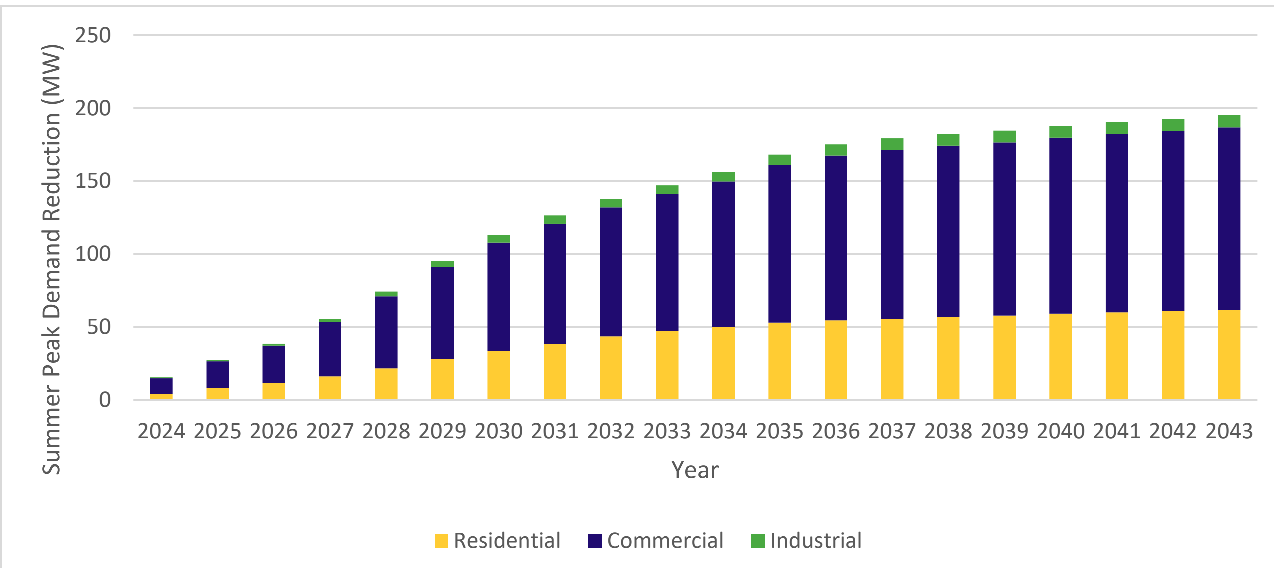
In alignment with the language of the November 7, 2024, directive to the IESO regarding a new energy efficiency framework for 2025–2036, this IRRP uses the term "electricity demand-side management" replacing "conservation and demand management (CDM)" used in previous IRRPs and other IESO planning reports.

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

The estimates of demand reduction due to program-related activities account for the IESO's 2021-2024 eDSM Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs. At time of forecast development, the 2021 – 2024 eDSM framework was the main piece, in which the IESO centrally delivered programs to serve business and residential customers, including Indigenous communities, across the province.[2]

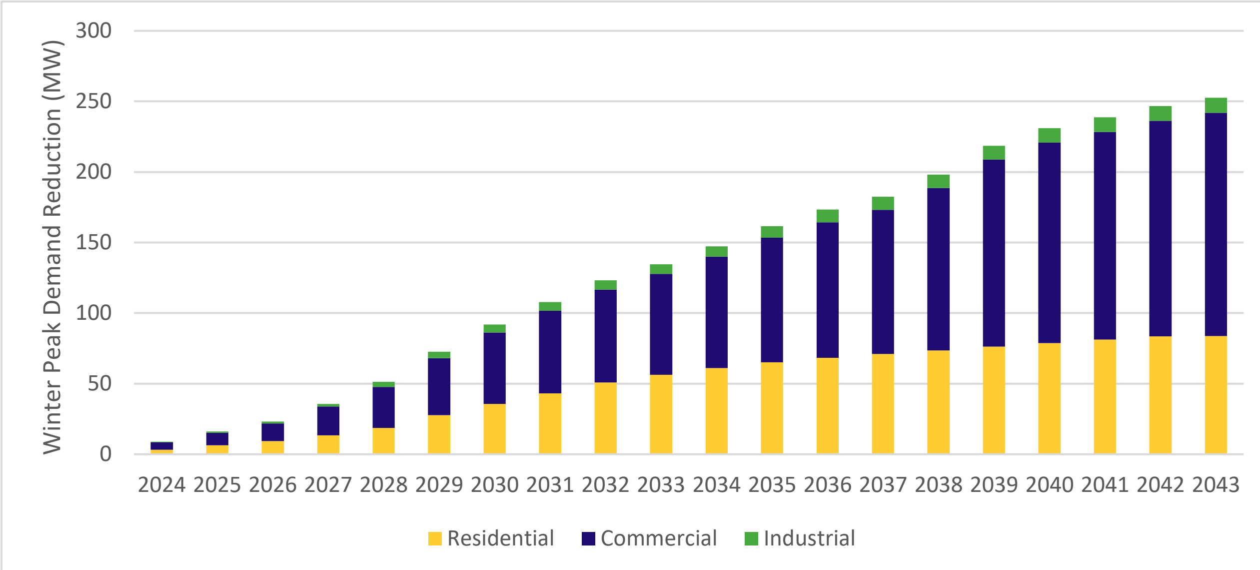
Figure 9 and **Figure 10** show the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards, and eDSM programs) for each of the residential, commercial, and industrial consumers. Additional details are provided in Appendix B.4.

Figure 9 | Total Summer Forecast Peak Demand Reduction (Codes, Standards, and eDSM Programs)



[2] The IESO has received a directive to continue delivering eDSM programs for 2025-2036.

Figure 10 | Total Winter Forecast Peak Demand Reduction (Codes, Standards, and eDSM Programs)



5.5 Contribution of Distributed Generation to the Forecast

In addition to eDSM, DG in the Ottawa Area Sub-Region is also forecast to offset peak demand requirements. The introduction of Ontario's FIT Program increased the significance of distributed renewable generation that, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and contribution factor assumptions can be found in Appendix B. Most of the total contracted installed DG capacity in the Ottawa Area Sub-Region is solar and hydro, with the remainder being gas or wind facilities.

After reducing the demand forecast due to eDSM, as described in Section 5.4, the forecast is further reduced by the expected contribution from contracted DG, except for DG facility information provided directly by the LDCs. **Figure 11** and **Figure 12** show the impact of DG on reducing the Ottawa Area Sub-Region demand forecasts. Note that facilities without a contract with the IESO were not included in the DG peak demand reduction forecast, except for DG facility information provided directly by the LDCs.

Figure 11 | Summer Peak Demand Reduction Due to DG

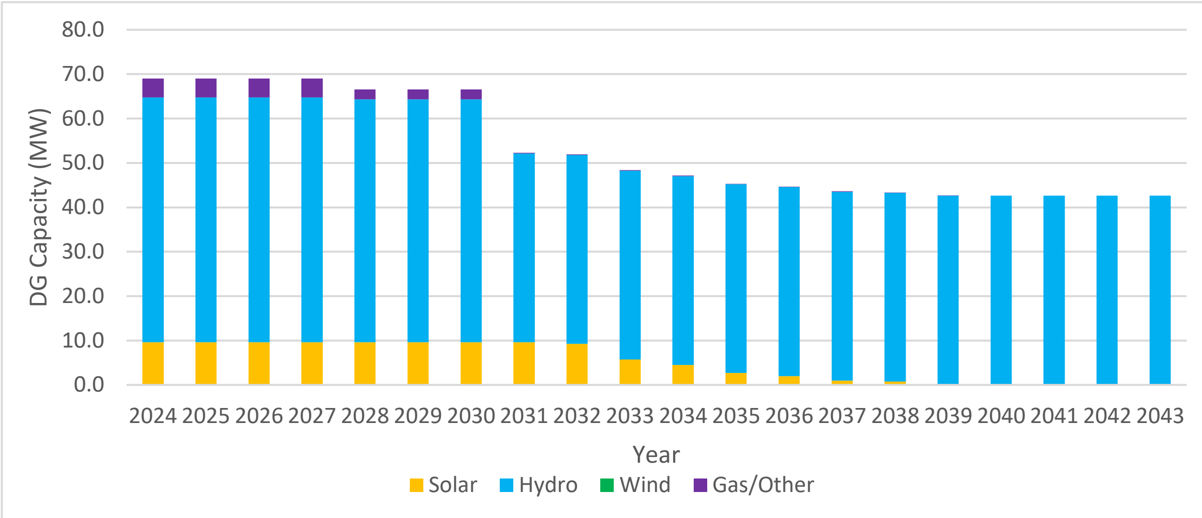
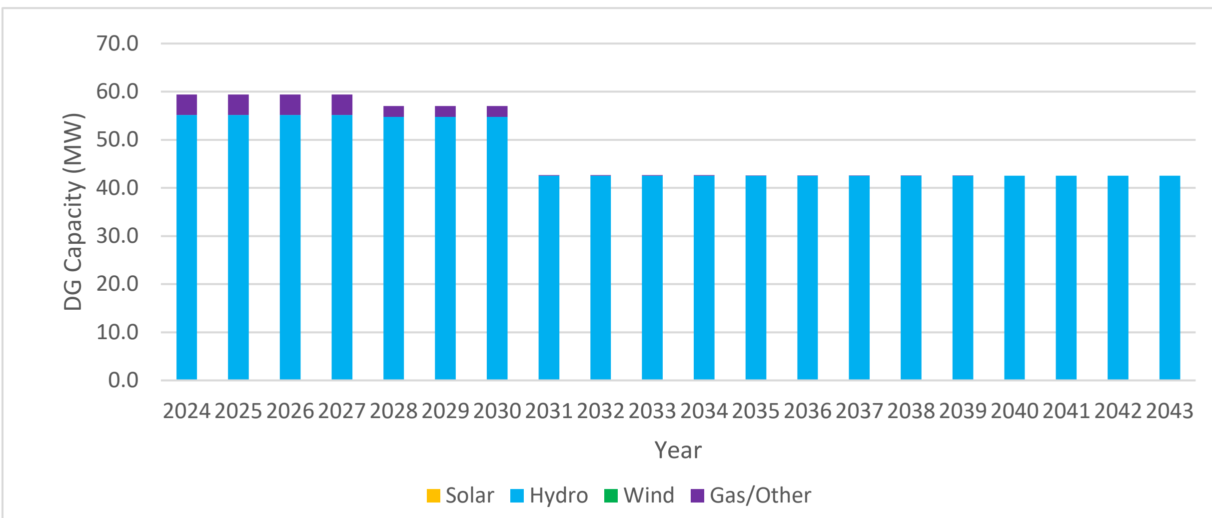


Figure 12 | Winter Peak Demand Reduction Due to DG



A decision was made within the Working Group to consider the expected lifespan of each distributed generation facility based on resource type, rather than assuming that facilities will not be re-contracted past their current contract end date. In alignment with the IESO 2024 Annual Planning Outlook, the assumption for resource expected lifespans was 25 years for solar, and 30 years for wind, natural gas and biogas.

A total of 115 MW of DG summer peak contribution and is identified for the Ottawa Area Sub-Region in 2024, reducing throughout the 2030s to 43 MW by 2043. In the winter, the DG peak contribution decreases from 70 MW in 2024 to 43 MW by 2043.

5.6 Planning Forecasts

After taking into consideration the combined impacts of eDSM and DG, a 20-year planning Reference and High forecast was produced for the Ottawa Area Sub-Region.

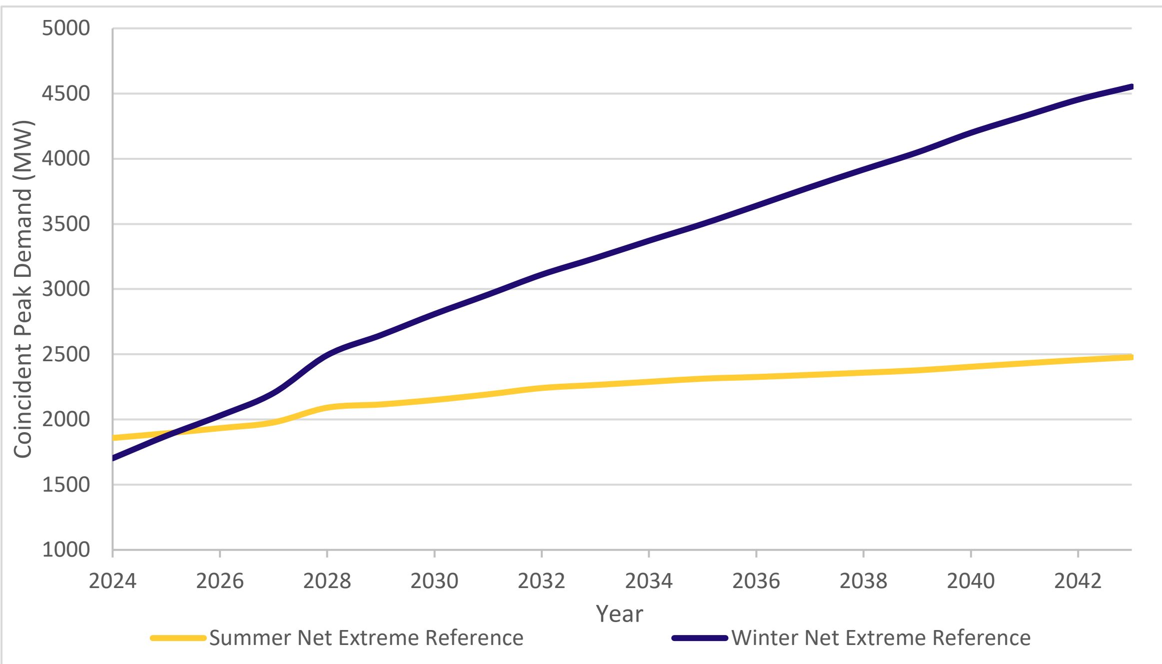
5.6.1 Net Extreme Weather (Planning) Forecast

The net extreme weather forecast, also known as the "planning" forecast, is created by adjusting the net median weather forecast (the gross demand forecast, plus the forecast DG and eDSM impacts as described above) for extreme weather conditions. The weather correction methodology is described in Appendix B.1.

Note that this planning forecast is coincident, meaning that each station forecast reflects its expected contribution to the regional peak demand level. This supports the identification of need dates for regional needs that are driven by more than one station.

The coincident net extreme weather forecast for the Ottawa Area Sub-Region is shown in **Figure 13**.

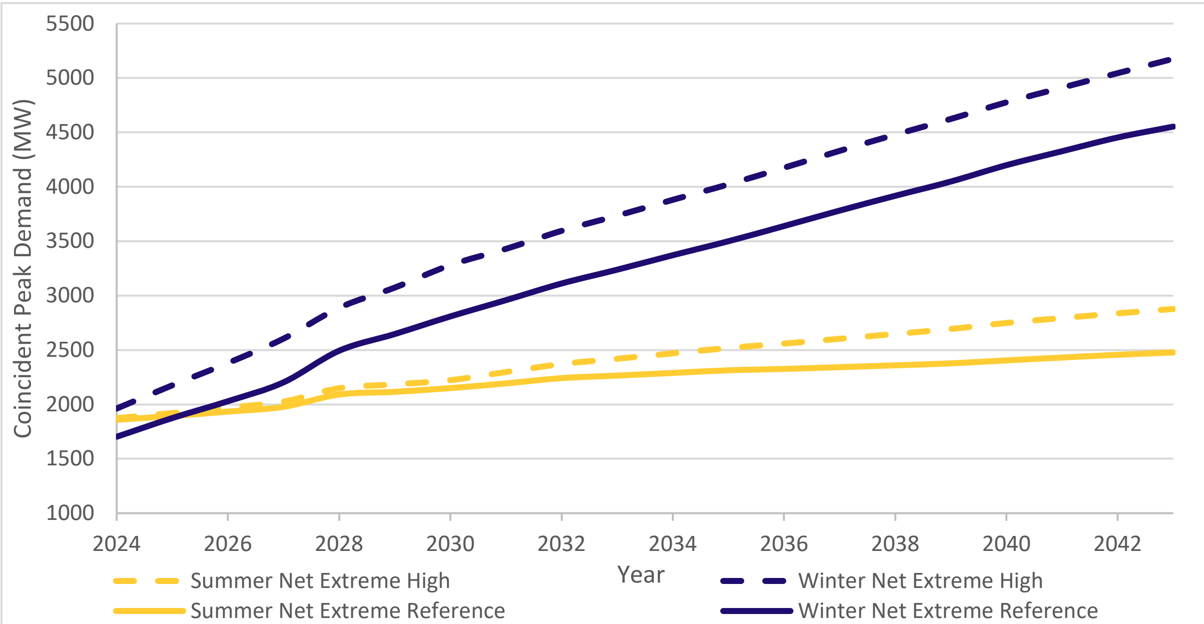
Figure 13 | Net Extreme Weather (Planning) Forecast for the Ottawa Area Sub-Region



5.6.2 High Forecast Scenario

The Working Group chose to develop a high-growth sensitivity scenario for the Ottawa Area Sub-Region. This scenario modifies assumptions around the adoption of electrification technologies and assumes a faster pace of decarbonization. While both the reference and high-growth scenarios aim for a net-zero future by 2050, they differ in the speed at which that transition occurs. The higher demand scenario was not used to drive firm recommendations in this IRRP; however, it served as a tool for the Working Group to identify potential future pinch points and the timelines in which they might emerge. This information is also valuable for communities working on Community Energy Plans for the Working Group as it determines areas to monitor in future planning cycles and for local stakeholders considering various regional projects. Additionally, during the course of this IRRP, the Working Group assessed the flexibility of the evaluated options to accommodate long-term growth.

Figure 14 | High Forecast Scenario for the Ottawa Area Sub-Region



The higher demand scenario, as seen in **Figure 14**, was not used to drive any firm recommendations for this IRRP; however, it was used to help the Working Group identify where the future pinch points may be and when they could materialize. This information can also be useful for communities conducting Community Energy Plans, for the Working Group in determining areas to monitor in future planning cycles, and for communities and stakeholders as they think about various projects in the region. Moreover, during this IRRP, the Working Group also considered the flexibility of evaluated options to accommodate greater long-term growth.

5.7 Hourly Forecast Profiles

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) for station(s) included in identified needs were developed to characterize the needs with finer granularity. The profiles were based on historical load data, adjusted for variables that impact demand, such as calendar day (i.e., holidays and weekends) and weather as well as future electrification. They were also based off of hourly load forecasts provided by the LDCs. The profiles were then scaled to match the IRRP peak planning forecast for each year. As described in Section 7, these profiles were used to quantify the magnitude, frequency, and duration of needs to better evaluate the suitability of generation and distributed energy resource options.

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

6. Needs

This section summarizes the needs identified through the IRRP process. The projected impacts of economic growth, decarbonization, and electrification—particularly the transition from natural gas to electric or hybrid heating—are expected to place increasing pressure on the electricity system, especially during winter months. In response, a range of electricity needs have been identified across near-, medium-, and long-term horizons.

6.1 Needs Assessment Methodology

Based on the planning demand forecast, system capability, the transmitter's identified asset replacement plans, and the application of ORTAC, NERC TPL-001-4, and Northeast Power Coordinating Council (NPCC) Directory #1 standards, the Working Group identified electricity needs that generally fall into the following categories:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day LTR of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by downstream or upstream equipment (i.e., breakers, disconnect switches, low-voltage bus or high-voltage circuits).
- **System Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is limited by the LMC of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-4, and NPCC Directory #1. LMC studies are conducted using power system simulation analyses.
- **Asset Replacement Needs** are identified by the transmitter using an asset condition assessment, which is based on a range of considerations, such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Replacement needs identified in the near- and early medium-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of

both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

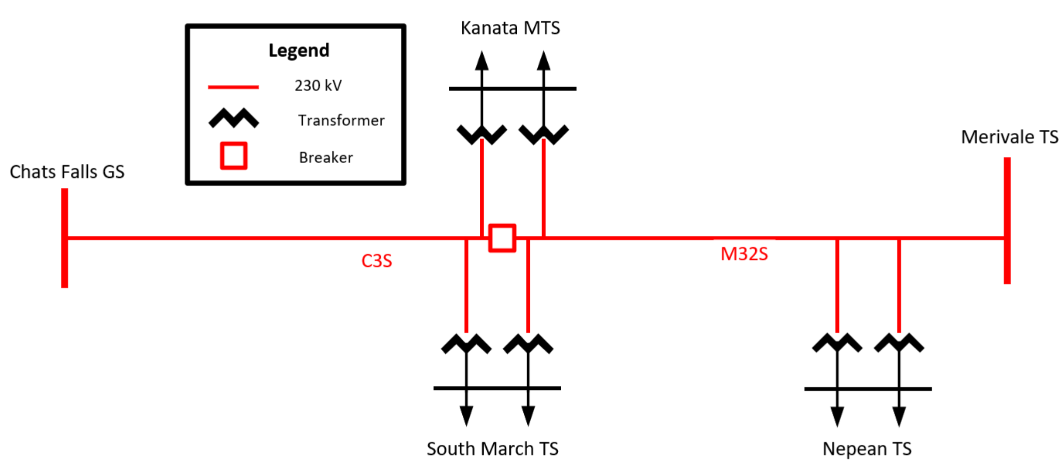
Technical study results for the Ottawa IRRP can be found in Appendix G. The needs identified are discussed in Sections 6.2 to 6.5, below, for each of the four subsystems.

6.2 Ottawa Subsystems

To support detailed technical analysis, the Ottawa Area Sub-Region has been further subdivided into four major subsystems: Kanata-Stittsville, Core East, Core West, and Core South. These subdivisions reflect the electrical connectivity of the transmission network and group together stations, supply circuits, and infrastructure that operate as electrically cohesive units. This approach allows for more accurate modelling of system performance, localized planning for station and System Capacity needs, and alignment with regional infrastructure development. Within each subsystem, further division into pockets is used where necessary to better reflect local electrical boundaries and simplify LMC assessments, as illustrated in **Figures 15–18**.

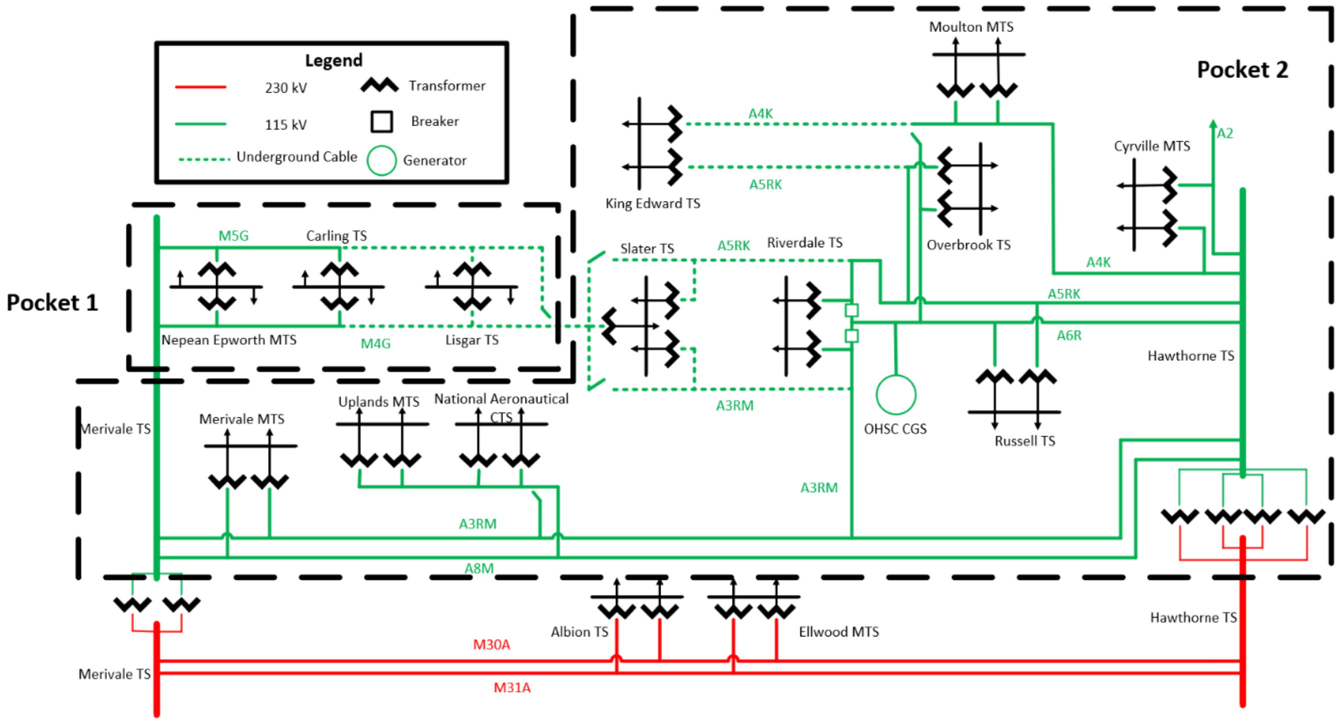
Located west of Merivale TS, the Kanata-Stittsville subsystem is supplied by two 230 kV circuits—one from Merivale TS and another from Chats Falls TS, which is approximately 25 km to the north and includes a hydroelectric generation component. These lines supply Kanata MTS and South March TS, both of which are projected to reach capacity in the near term and are identified as key station needs. As shown in **Figure 15** this subsystem's layout enables focused planning to address rising demand and operational risk. While Marchwood MTS and Bridlewood MTS are located geographically within this area, they are supplied via the 115 kV system and are therefore included in the Core West subsystem.

Figure 15 | Overview of the Ottawa Kanata-Stittsville area



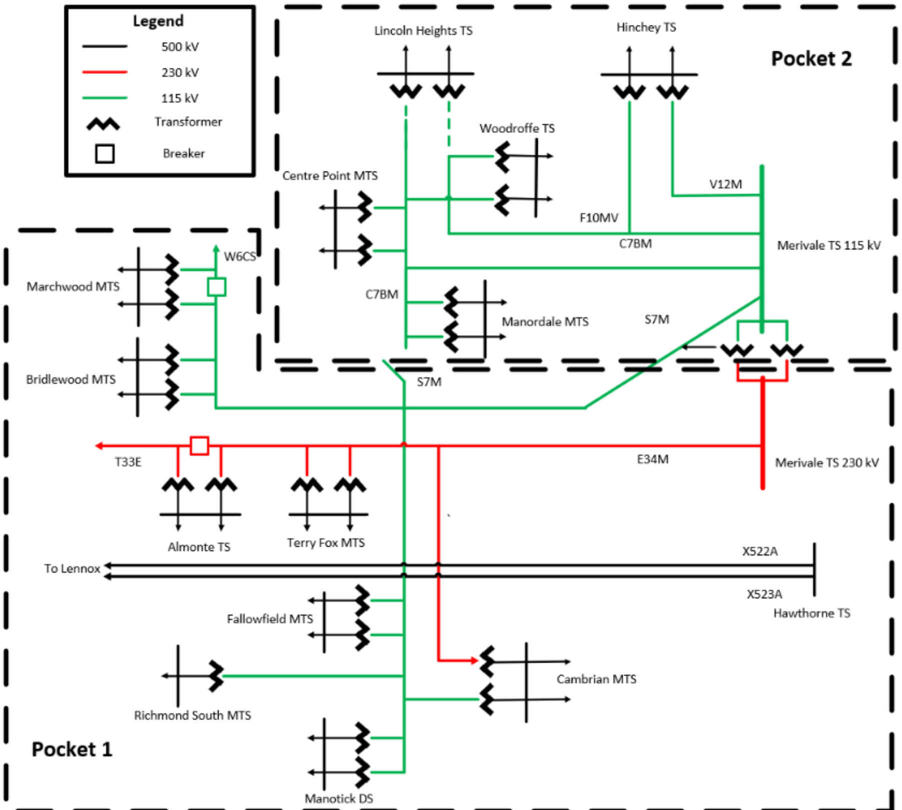
The Core East subsystem represents Ottawa's urban downtown core and is characterized by a large, interconnected 115 kV system. For the purposes of the technical studies and to support more manageable modelling, Core East is divided into two pockets. Pocket 1 consists of circuits M4G and M5G, which supply Nepean Epworth MTS, Carling TS, and Lisgar TS. Notably, M4G also provides one of three supplies to Slater TS. The remaining 115 kV circuits form Pocket 2, supplying the remaining downtown stations predominantly east of the Rideau River. **Figure 16** illustrates this breakdown, allowing for better assessment of local supply adequacy and reinforcement needs.

Figure 16 | Overview of the Ottawa Core East Area



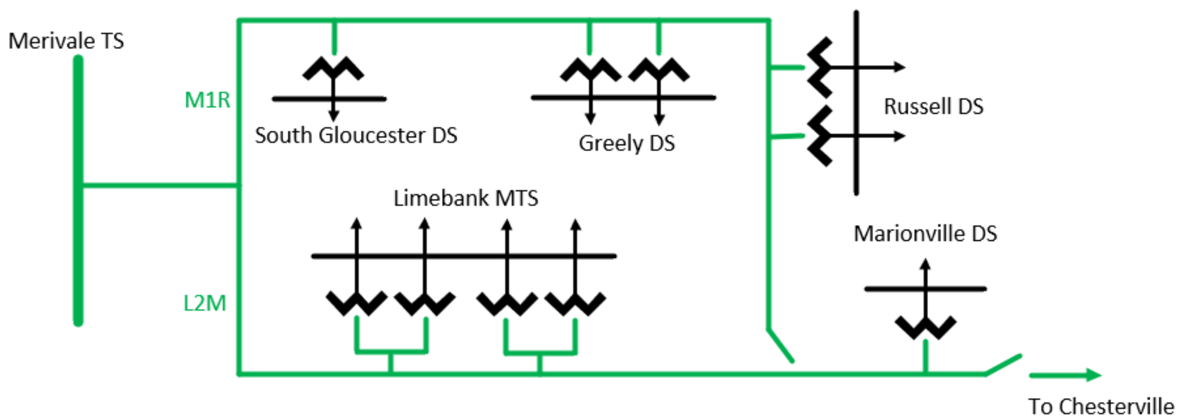
Core West has also been divided into two pockets to reflect the operational and electrical characteristics of the area. Pocket 1 includes stations supplied by 115 kV circuits S7M and W6CS, as well as 230 kV circuit E34M. All three connect at Cambrian TS, where a Fast Transfer Scheme (a RAS) is used to quickly restore load in the event of a circuit loss, avoiding the need for more expensive dual 230 kV supply infrastructure. This pocket includes several stations experiencing or approaching capacity limits. **Figure 17** depicts the full subsystem and pocket breakdown, supporting the identification of local needs and future conversion opportunities.

Figure 17 | Overview of the Ottawa Core West Area



The Core South subsystem comprises the area south of Ottawa's urban core and includes five supply stations served radially by two 115 kV circuits. The stations are relatively remote and less interconnected compared to those in other subsystems. **Figure 18** shows the simplified layout of this subsystem. The 2020 Ottawa IRRP identified the need for a new 230 kV station—Piperville MTS—to support rapid growth in the southeastern portion of the city. Connected to circuit L24A, Piperville MTS is expected to be energized in 2026 and will play a key role in alleviating station capacity constraints in the area and supporting long-term system reliability.

Figure 18 | Overview of the Ottawa Core South Area



6.3 Station Capacity Needs

Many station capacity needs emerge in the Ottawa Area Sub-Region, as shown in **Table 5** with the majority in the near/medium term.

Table 5 | Summary of Station Capacity Needs in the Ottawa Area Sub-Region

Time Horizon	Station	Subsystem	Emerging Year Summer	Emerging Year Winter	2043 Need Summer (MW)	2043 Need Winter (MW)
Near Term	Carling TS	Core East – Pocket 1	2028	2029	40	130
	Lisgar TS	Core East – Pocket 1	2025	2027	30	120
	Nepean Epworth MTS	Core East – Pocket 1	2031	2028	1	10
	Cyrville MTS	Core East – Pocket 2	-	2029	0	40
	King Edward TS	Core East – Pocket 2	2037	2026	10	160
	Moulton MTS	Core East – Pocket 2	2028	2028	3	30
	Riverdale TS	Core East – Pocket 2	2038	2028	8	110
	Ellwood MTS	Core East – Pocket 2	2024	2027	60	5
	Bridlewood MTS	Core West – Pocket 1	2032	2029	1	20

Time Horizon	Station	Subsystem	Emerging Year Summer	Emerging Year Winter	2043 Need Summer (MW)	2043 Need Winter (MW)
	Fallowfield MTS	Core West – Pocket 1	2024	2030	7	40
	Marchwood MTS	Core West – Pocket 1	2025	2025	8	40
	Centrepoint MTS	Core West – Pocket 2	2024	2026	2	20
	Manordale MTS	Core West – Pocket 2	2024	2025	3	20
	Greely DS	Core South	2024	2024	10	10
	Limebank MTS	Core South	-	2030	0	50
	Marionville DS	Core South	2026	2026	10	10
	Kanata MTS	Kanata-Stittsville	2024	2026	20	40
	South March TS	Kanata-Stittsville	2027	2027	20	100
Medium Term	Overbrook TS	Core East – Pocket 2	-	2032	0	90
	Hawthorne TS	Core East – Pocket 2	-	2031	0	60
	Hinchey TS	Core West – Pocket 2	-	2033	0	60
	Nepean TS	Kanata-Stittsville	-	2031	0	100
Long Term	Merivale MTS	Core East – Pocket 2	-	2039	0	7
	Uplands MTS	Core East – Pocket 2	-	2041	0	5
	Albion TS	Core East – Pocket 2	-	2035	0	40
	Cambrian MTS	Core West – Pocket 1	-	2038	0	20
	Richmond South MTS	Core West – Pocket 1	-	2037	0	10
	Terry Fox MTS	Core West – Pocket 1	-	2037	0	30
	Lincoln Heights TS	Core West – Pocket 2	-	2040	0	10
	Woodroffe TS	Core West – Pocket 2	-	2040	0	10

6.3.1 Station Capacity Needs Kanata-Stittsville Subsystem

Kanata MTS has an LTR of 54 MW and is forecast to exceed capacity by 2024 in summer and 2026 in winter. By 2030, the projected winter overload is 15 MW, indicating continued and significant growth in demand. This early emerging need reflects increasing development across the Kanata area, necessitating reinforcements or capacity upgrades within the near term.

South March TS, with a winter LTR of 120 MW and summer LTR of 105 MW, is forecast to reach capacity by 2027 in both seasons. By 2030 the winter overload is projected to reach 23 MW. The station's two 230/44 kV transformers, in service since 1971, are due for replacement between 2030–2032, and the Working Group is evaluating whether to replace them with larger 75/100/125 MVA units.

Nepean TS has a winter LTR of 170 MW and is expected to exceed this rating by 2031. Although there is no summer need forecasted, the station is facing a load security issue: winter peak demand is projected to exceed 150 MW by 2029, and with M32S as the sole supply, an outage would violate ORTAC criteria by resulting in a full load loss. Addressing this concern will require both capacity and contingency planning for secure operation in the Kanata-Stittsville area.

6.3.2 Station Capacity Needs Core East Subsystem

Carling TS has a summer LTR of 100 MW and a winter LTR of 132 MW. It is projected to exceed capacity in 2028 (summer) and 2029 (winter). By 2030, the winter overload is expected to reach 17 MW, driven by ongoing electrification in Ottawa's downtown core. It is important to note that both Carling TS and Lisgar TS have hydroelectric generation supplying each station which has been accounted for in the forecast but contributes to the variability of the station capacity need.

Lisgar TS has an LTR of 77 MW (summer) and 86 MW (winter), with capacity needs emerging as early as 2025 (summer) and 2027 (winter). By 2030, the projected winter overload reaches 40 MW, one of the highest in the region driven by winter heating load as well as large customer connections.

Nepean Epworth MTS has an LTR of 13 MW for both summer and winter. It is forecast to reach capacity in 2031 (summer) and 2028 (winter), with a 2 MW winter overload expected by 2030. This modest but significant overload reflects continued urban infill in the surrounding residential area, requiring minor station upgrades or targeted load transfers.

Cyrville MTS, rated at 45 MW, is forecast to exceed capacity in 2029 (winter). The projected winter overload by 2030 is 3 MW. While no summer need is currently identified, load growth in the adjacent industrial and commercial areas is expected to continue contributing to the station's winter peak constraint.

King Edward TS has LTRs of 92 MW (summer) and 96 MW (winter). The winter capacity need is projected to emerge by 2026, with the overload reaching 40 MW by 2030. Though the summer need emerges much later (2037), the station will require substantial reinforcement to manage escalating winter demand, especially from institutional and high-density residential growth downtown.

Moulton MTS is rated at 33 MW in both seasons. It is expected to exceed capacity by 2028 (both summer and winter), with an 8 MW winter overload forecasted for 2030. Located in a growing mixed-use area, the station will require capacity upgrades or operational measures to accommodate new developments.

Riverdale TS has a summer LTR of 118 MW and a winter LTR of 124 MW. While its summer need arises in 2038, winter constraints begin much sooner, with a need emerging in 2028 and a 20 MW overload projected by 2030. The area includes a mix of mature neighbourhoods and new high-rise developments, putting increasing strain on winter capacity.

6.3.3 Station Capacity Needs Core West Subsystem

Bridlewood MTS has an LTR of 23 MW in both summer and winter. Winter need is expected by 2029, with a 2 MW overload projected by 2030. The summer need follows in 2032. This modest overload is driven by steady residential development and densification in the surrounding suburbs.

Centrepoint MTS has an LTR of 13 MW for both seasons and is expected to exceed capacity by 2024 (summer) and 2026 (winter). By 2030, the winter overload is forecast at 5 MW, indicating a strong and persistent local demand requiring targeted capacity relief in the near term.

Fallowfield MTS is rated at 25 MW and is projected to reach its summer capacity by 2024, followed by winter needs emerging in 2030. An 11 MW summer overload is forecast for 2030. Situated near key growth corridors, this station will need reinforcement to manage short- and medium-term demand increases.

Manordale MTS has an LTR of 9 MW and is expected to exceed capacity by 2024 (summer) and 2025 (winter). The projected winter overload reaches 5 MW by 2030. The small size of the station and its location in a maturing neighborhood mean that even moderate demand growth results in capacity pressure.

Marchwood MTS is rated at 30 MW and is expected to exceed capacity in both 2024 (summer) and 2025 (winter). By 2030, the winter overload is projected to reach 17 MW, making it one of the most constrained stations in the Core West subsystem. Rapid suburban expansion and limited load transfer capability intensify the need for reinforcement.

6.3.4 Station Capacity Needs Core South Subsystem

Limebank MTS has an LTR of 89 MW and is forecast to reach capacity in 2030 (winter), the LTR is limited by a load security constraint, once this is remedied the LTR of the station increases significantly. By 2030, the projected winter overload is modest at 1 MW, but demand is expected to intensify as development continues along the expanding Limebank corridor. Early planning for reinforcement may help pre-empt longer-term constraints. Greely DS is expected to reach its LTR in 2024 and Marionville DS in 2026.

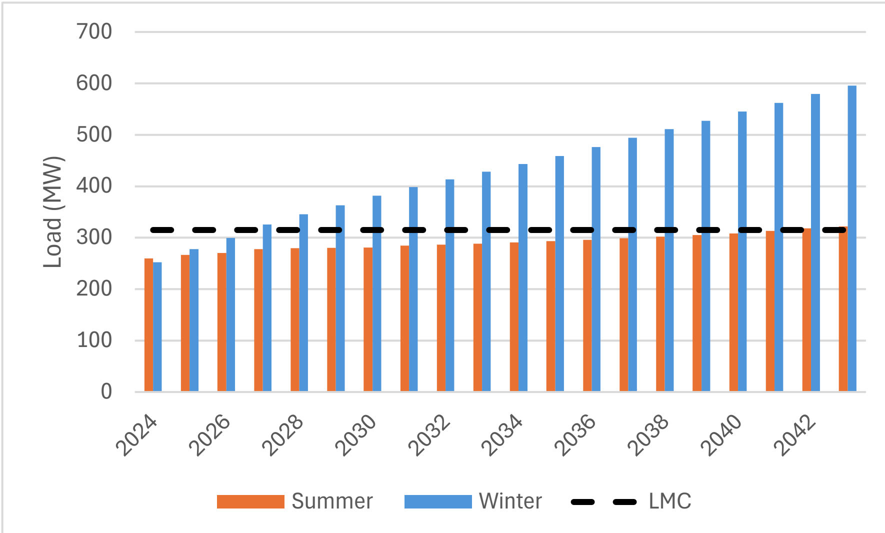
6.4 System Capacity Needs

6.4.1 System Capacity Needs Kanata-Stittsville Subsystem

This subsystem is supplied by two transmission circuits, one from Chats Falls (C3S) and one from Merivale TS (M32S). The loss of both of these circuits would mean all stations in the area (Kanata MTS, South March TS, and Nepean TS) would be out of power. This would be a load security consideration, the maximum allowable load lost by configuration for two elements is 600 MW and as their combined LTR is 312 MW in the summer and 345 MW in the winter. The subsystem only reaches 600 MW in the winter in 2043 which assumes a fully electrified heating load.

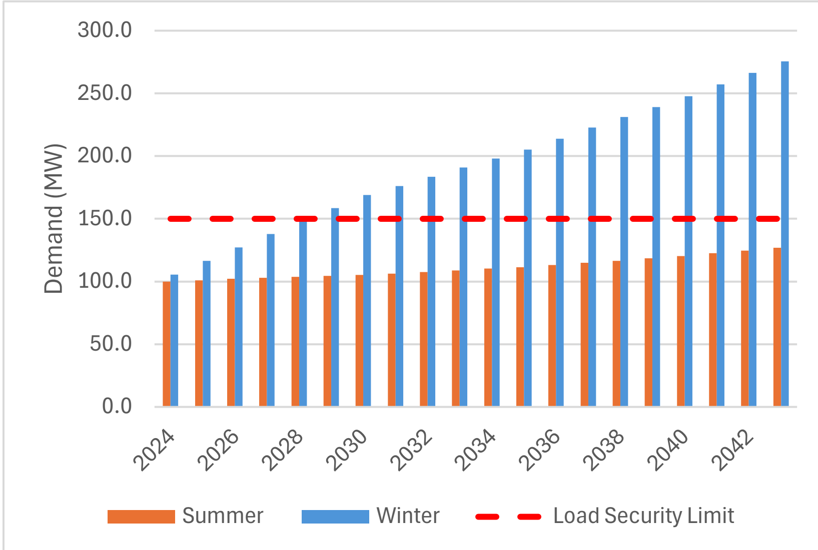
Losing either of the circuits supplying the area leads to voltage instability at varying load levels and it was found that the most limiting configuration is having M32S on outage followed by a contingency on C27P. This occurs at roughly 310 MW which is near the summer LTR for the subsystem as seen in **Figure 19**. There are no System Capacity needs for the summer forecast.

Figure 19 | Reference Forecast vs LMC for Kanata-Stittsville



There is also an additional load security issue in this subsystem as well. For an M32S contingency, beyond losing one of the two supply circuits for this subsystem, the entire load at Nepean TS is lost by configuration as well. Load security requires that no more than 150 MW can be lost for a single element contingency. **Figure 20** shows the Nepean TS forecast compared to this limit. This limit is not reached in the summer forecast, but is reached in 2029 in the winter forecast.

Figure 20 | Nepean Load Forecast vs Load Security Limit



6.4.2 System Capacity Needs Core East

Core East Pocket 1 is supplied by circuits M5G and M4G. The limiting phenomenon is a thermal overload on each circuit when the companion circuit is lost, as both Lisgar TS and Carling TS would be fully supplied by the remaining circuit. It was found that a contingency to M5G was more limiting, leading to an LMC of 223 MW, as seen in **Figure 21**.

Core East Pocket 2 consists of many more circuits and stations. The combined LTR of all the stations is about 600 MW, or just above 750 MW, including Slater TS. This is important because the summer forecast does not reach this figure, while the winter forecast exceeds it by over 600 MW as seen in **Figure 22**. The studies evaluating the system today find that voltage instability issues occur at a loading above the combined station LTR.

Figure 21 | Reference Forecast vs LMC for Pocket 1

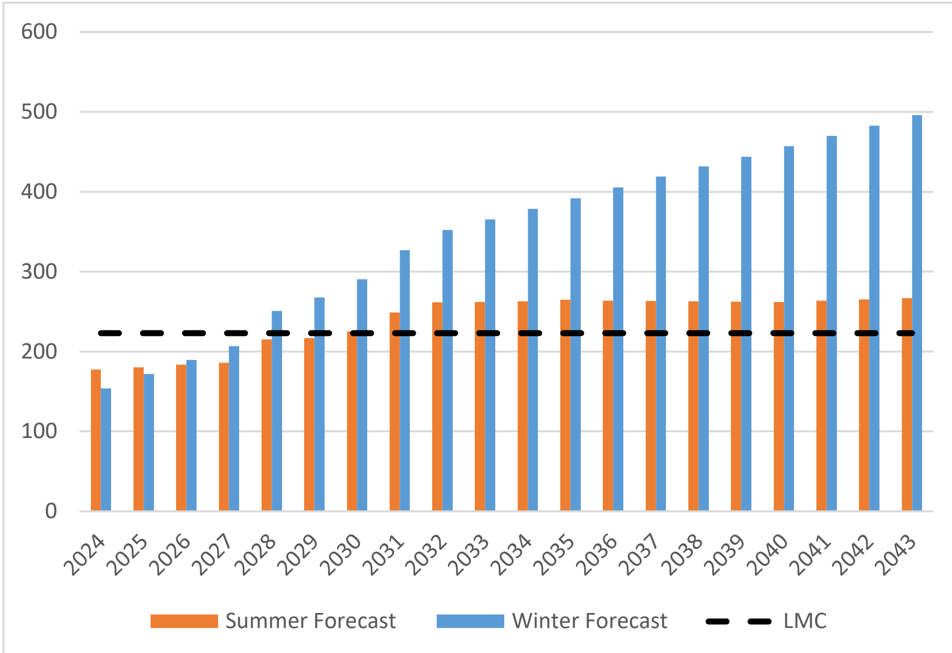
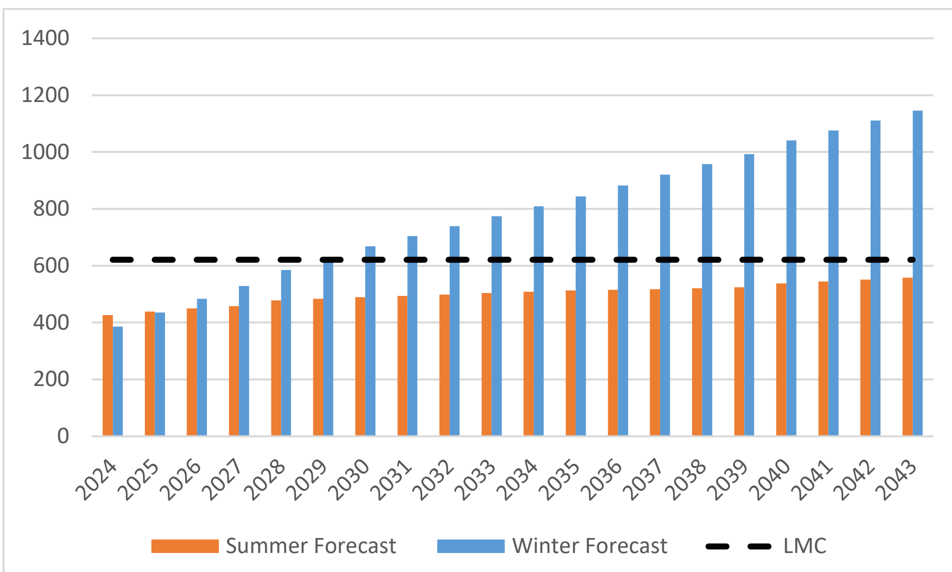


Figure 22 | Reference Forecast vs LMC for Pocket 2



6.4.3 System Capacity Needs Core West Subsystem

The Core West subsystem was found to have healthy voltages, and no voltage violations were found as part of the technical studies. The LMC of the two pockets was found to be limited by thermal overloads. For Pocket 1, which is made up of loads supplied by S7M, as seen in **Figure 17**, the most limiting contingency is a loss of E34M, which transfers Cambrian MTS onto S7M, leading to a thermal overload on the branch of circuit emanating from Merivale TS to the junction right before the circuit continues south, which is approximately 5km long. **Figure 23** shows that the forecast will not exceed the identified limit of approximately 250 MW in the summer but will do so in the winter in the medium-term.

As for pocket 2, the thermal overload identified as the most limiting occurs during a contingency to F10MV which places both Woodroffe TS and Lincoln Heights TS solely on C7BM, where thermal overloads begin to occur at around 230 MW of combined station load. The loss of C7BM also causes an overload on certain sections of F10MV, but is not more limiting. **Figure 23** and **Figure 24** illustrate the limits versus the expected forecast. In both cases, these needs occur only in the winter.

Figure 23 | Reference Forecast vs LMC for Core West Pocket 1

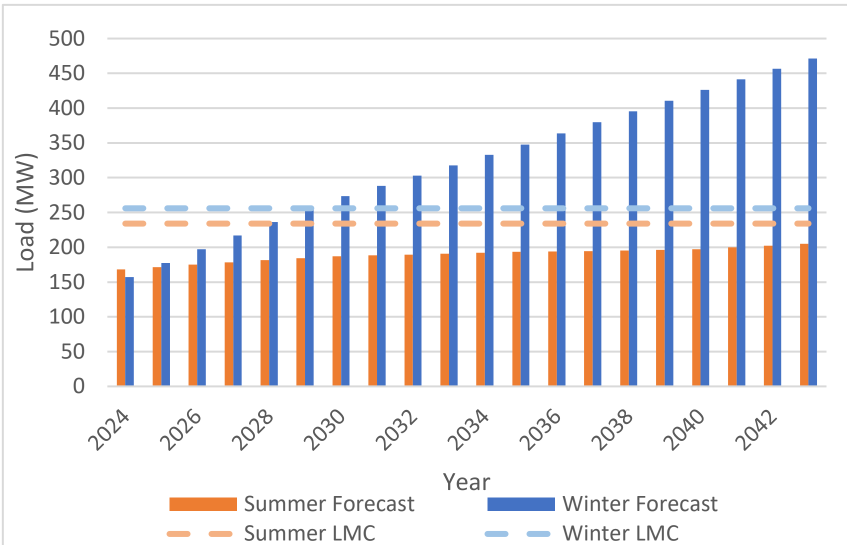
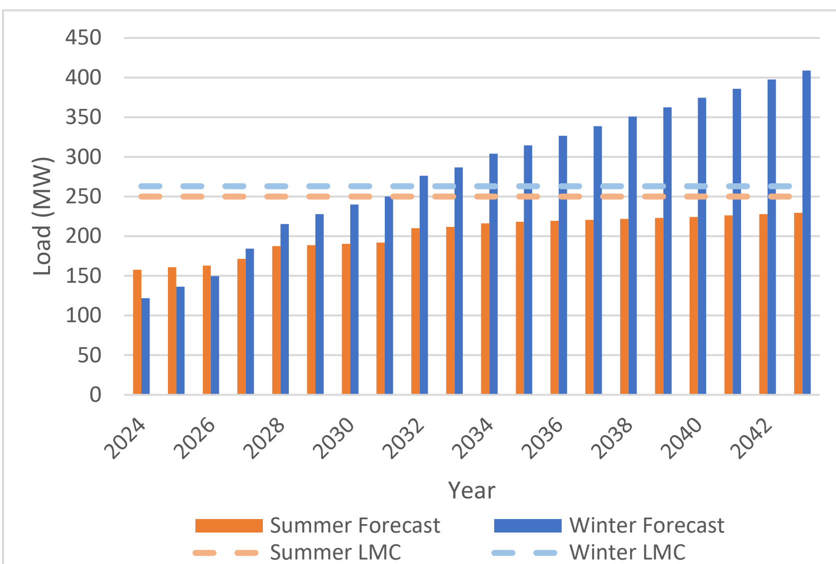


Figure 24 | Reference Forecast vs LMC for Core West Pocket 2

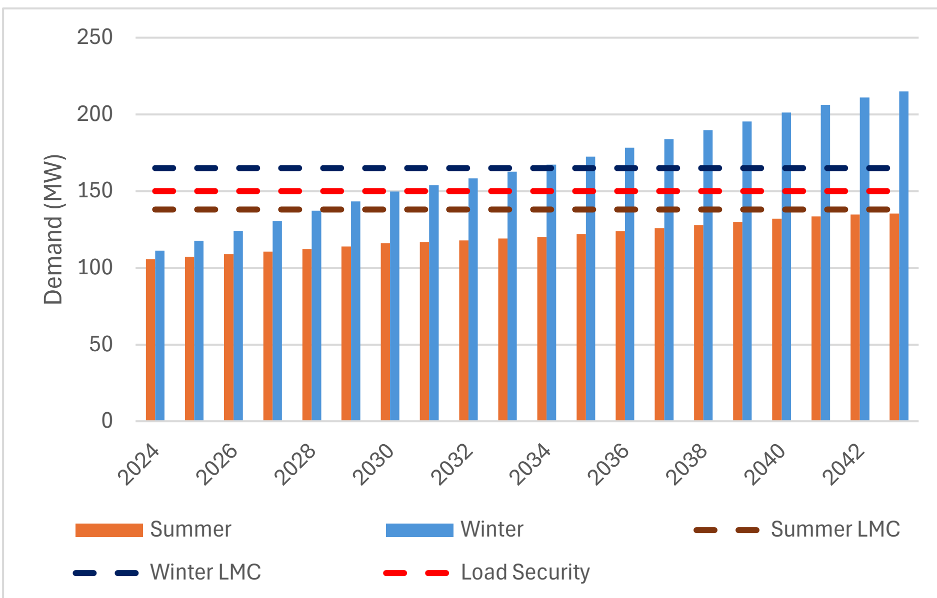


6.4.4 System Capacity Needs Core South Subsystem

There are no relevant contingencies to study in this area, since the loss of either circuit results in both circuits being tripped. This is due to L2M and M1R sharing a breaker position at Merivale TS. The limiting phenomenon in Core South is a thermal overload on the portion of L2M between Merivale TS and Limebank MTS, which occurs around the end of the medium term (2034). By scaling the stations how they are expected to grow in the next 20 years, this thermal overload happens at a load of 140 MW in the summer and 165 MW in the winter among the five stations in the subsystem. This overload is almost entirely caused by the loading on Limebank MTS. The second most limiting phenomenon in this subsystem would be voltage instability, but this limit is not approached in the 20-year forecast. The combined LTR of the stations in Core South is 160 MW in both summer and winter, meaning the limit of this subsystem is reached around the same time the station capacities would be reached.

Core South also has a limit on its total load growth of 150 MW, due to load security as seen in **Figure 25**. By design, the system must limit load loss to no more than 150 MW if a single element fails. In Core South, however, the two lines share a breaker position, so a contingency (fault) on one line causes both to be out of service. This effectively makes the two circuits a single element. As a result, this configuration becomes the most limiting factor in the winter.

Figure 25 | Reference Forecast vs LMC for Core South



6.5 End-of-Life/Asset Replacement Needs

6.5.1 Asset Replacement Needs Core East Subsystem

Lisgar TS has an LTR that is expected to be exceeded in 2026, based on the coincident forecast. Transformer T1 was in-serviced in 1974 and needs replacement. This replacement to a 45/60/75MVA transformer was planned to be in-serviced 2031–2033.

The Working Group determined that the transformer should be upgraded to a 60/80/100 MVA unit, instead of a 45/60/75MVA unit.

6.5.2 Asset Replacement Needs Core West Subsystem

Sections of circuit S7M have asset renewal needs. Decisions on the preferred option to address the asset renewal need should consider prefer supply configuration for the area. Two sections that need to be refurbished are Manotick JCT x Richmond MTS (5.2km) and STR 673N JCT x Manordale MTS (1.4km). The Working Group recommends the need be further reviewed to determine the preferred supply option for the area.

6.5.3 Asset Replacement Needs Core South Subsystem

No asset replacement needs were identified for Core South.

6.5.4 Asset Replacement Needs Kanata-Stittsville Subsystem

South March TS has an LTR that is expected to be exceeded in 2027 based on the coincident forecast.

South March has two 230kV/44kV, 50/67/83 MVA transformers in-serviced in 1971 which need replacement. The Working Group recommends to upgrade the transformers to 75/125 MVA units. This project is planned to have an in-service date of 2030–2032.

7. Plan Options and Recommendations

This section outlines the options considered and presents recommendations to address the electricity needs in the Ottawa Area Sub-Region. In developing the plan, the Working Group considered a range of integrated solutions, taking into account factors such as feasibility, cost, implementation timelines, system benefits, and consistency with the region's long-term electricity needs.

To meet the growing regional electricity demand, there are generally two types of approaches:

- Transmission/Distribution Infrastructure Expansion ("Wires" Options): These involve building new facilities or upgrading existing assets to increase the area's LMC. Examples include new transmission lines, autotransformers, step-down transformer stations, voltage control devices, or enhancements to existing infrastructure. Wires solutions may also encompass operational measures such as control actions or protection schemes that optimize system performance and mitigate reliability concerns.
- Demand Reduction, Management, or Local Generation ("Non-Wires" Solutions): These aim to reduce peak electricity demand so that it remains within the system's existing LMC. Examples include local utility-scale generation or energy storage, distributed energy resources (such as distribution-connected generation and demand response), demand-side management programs, and distribution-level load transfers.

Section 7.1 provides a detailed overview of the various types of options typically considered in Integrated Regional Resource Plans. Section 7.2 outlines the screening methodology used to identify which needs were most appropriate for further assessment of non-wires solutions. Sections 7.3 through Section 7.6 present the specific options that were developed and evaluated, leading to the Working Group's final recommendation.

7.1 Options Considered in IRRPs

Wires solutions are a core part of regional planning and are developed by identifying transmission upgrades or control measures tailored to address the specific technical limitations—such as voltage, thermal, or stability concerns—associated with each need. These solutions are shaped through collaboration with the Working Group.

While traditional wires infrastructure remains a reliable solution for addressing regional electricity needs, certain non-wires options may be better suited to specific types of needs and system characteristics. Selecting and sizing these alternatives—such as local generation or storage—requires additional analysis, including the development of an hourly load profile, as outlined in Section 5.7. The most appropriate technology and capacity are determined by examining the "unserved energy" profile, which highlights the portion of demand that exceeds the area's existing LMC. This profile provides key insights into the duration, frequency, magnitude, and total energy shortfall for each identified need. Visual representations of these characteristics for the Ottawa Area Sub-Region are provided in Appendix D.

High-level cost estimates for wires options are provided by the transmitter. For non-wires alternatives—such as generation or storage—cost estimates are based on industry benchmarks for capital and operating cost characteristics for each resource type and size. The costs for wires options presented are in terms of capital costs and represent a high level planning estimate while non-wires costs are net present value. In line with current policy direction and decarbonization goals, new natural gas-fired generation was not considered. Instead, battery energy storage, solar, and wind generation were evaluated as potential non-wires solutions.

Additional eDSM programming can also help decrease the net electricity demand. Expected peak demand savings from the 2021-2024 eDSM framework and subsequent frameworks (under the **Save on Energy brand**) are already included in the load forecast, as discussed in the Section 5.4. As part of this framework and the new 2025-2036 framework, the IESO was enabled to deliver a new program to address regional and/or local system needs. The **Local Initiative Program** is now one tool that is available to target the delivery of additional eDSM savings at specific areas of the province with identified system needs. LDCs can also use the Ontario Energy Board's Non-Wires Solutions Guidelines for Electricity Distributors to leverage distribution rates to help address distribution and transmission system needs using non-wires alternatives.[3] Generally, incremental eDSM measures are suitable for needs where growth is slow and the magnitude of the overload relative to the total demand is very small (i.e., on the order of few percent per year). These considerations are discussed further in Section 7.2, as part of the screening of options that was conducted.

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

It's important to note that planning-level cost estimates carry a significant margin of uncertainty, as they are developed without detailed engineering design or field assessments. These estimates are intended to support high-level comparisons between options during the IRRP process, rather than provide precise project costs. The RIP, which follows the IRRP and/or supports specific projects, includes more detailed analysis and provides an opportunity to refine cost estimates for wires solutions. The IESO remains actively involved in the Working Group during the RIP and engages with the transmitter if significant differences in cost estimates arise. In cases where downstream barriers—such as regulatory challenges around cost-sharing or the need to address local reliability constraints—limit the implementation of otherwise cost-effective solutions, pilot or demonstration projects may be pursued to explore their feasibility.[4]

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

[3] More information about the eDSM Guidelines is available on the Ontario Energy Board's **website**

[4] Barriers to non-wires alternatives and recommendations to address them were a part of the **Regional Planning Process Review**

7.2 Screening Options

As explained in Section 7, an array of options can be developed to meet local needs during an IRRP, but options are ultimately evaluated to recommend the option that is most cost effective, or the option that best balances cost and risk mitigation when substantial additional risks not captured by the Planning forecast are present. This process is complemented by considerations for stakeholder preferences and feedback.

Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed non-wires analysis (hourly need characterization, options development, financial analysis, and engagement) toward the most promising options. The three-step, high-level approach is shown in **Figure 26**, and the results of its application to the Ottawa Area Sub-Region IRRP needs are summarized in **Table 6** and then further described in **Table 7** and in the sections below.

More details on the steps and inputs used in the screening mechanism can be found in Appendix C.

Figure 26 | IRRP Screening Mechanism

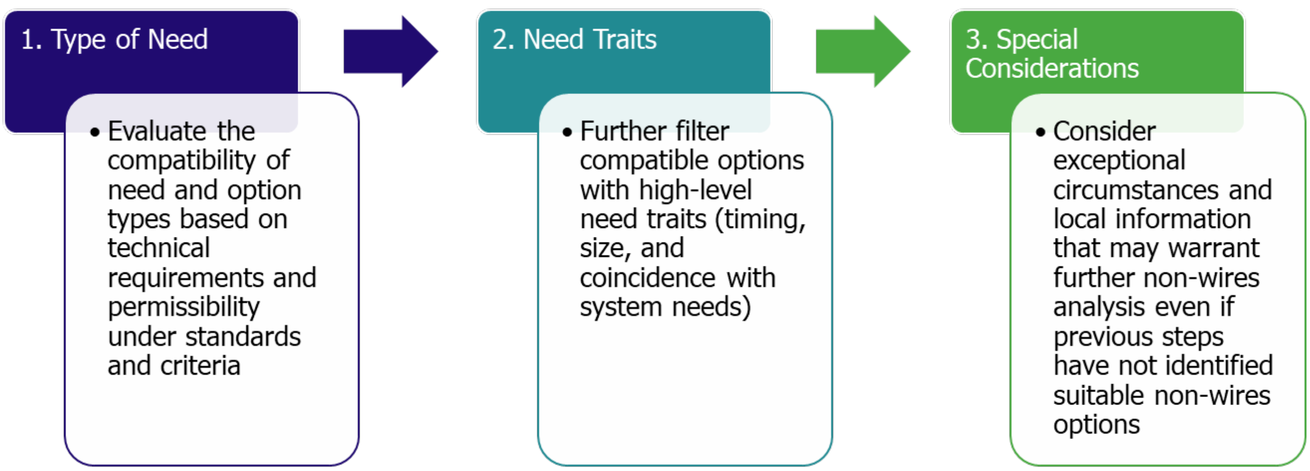


Table 6 | Options Screening Results for Station Capacity Needs

Need	Screened In	Screened Out
Station Capacity	• eDSM • Distributed generation • Wires options	• Demand response – due to magnitude and timing of needs, and limited DR capacity historically offered in this area • Operational measures

Table 7 | Options Screening Results for System Capacity Needs

Need	Screened In	Screened Out
System Capacity: Thermal, Voltage, Load Security	• eDSM • Distributed generation • Transmission-connected generation • Wires options	• Demand response – due to magnitude and timing of needs, and limited DR capacity historically offered in this area • Operational measures due to complexity of Ottawa system

7.2.1 Non-Wires Options for the Station Capacity Needs

A range of non-wires solutions—including transmission-connected generation, BESS, demand response, and hybrid approaches—were considered as part of the planning process. Given the significant forecasted load growth and the resulting number of station capacity needs, a practical screening approach was necessary to focus on the most feasible and impactful options. While eDSM programs alone are unlikely to significantly defer most of the identified needs, they remain important for slowing the pace of demand growth—supporting the timely development of long-term infrastructure solutions.

Due to the time and resources required for in-depth evaluation, it was not practical to assess non-wires options at every individual station. Instead, needs were grouped and prioritized based on where non-wires solutions—such as wind, solar, and battery storage—were most likely to be viable. This focused analysis was conducted for station groups within the Kanata-Stittsville, Core East Pocket 1, and Core East Pocket 2 subsystems.

7.2.2 Non-Wires Options for the System Capacity Needs

Among the System Capacity needs identified, four circuits were found to be limited by thermal constraints. Based on the current range of non-wires solutions, none were considered feasible for addressing these specific limitations. In contrast, the voltage stability concern identified in the Kanata-Stittsville subsystem was well suited for non-wires options and was therefore examined in greater detail. Additionally, two major battery storage projects—each exceeding 100 MW—have been proposed in the Ottawa area. Their potential impact on the regional electricity system has been assessed, with findings and observations outlined below.

7.3 Options and Recommendations for the Kanata-Stittsville Subsystem

The Kanata-Stittsville subsystem, while relatively straightforward in design, is facing rapid load growth and is expected to reach its LMC in the near term. Technical studies show that the loss of either of the two existing supply circuits—particularly from Merivale TS—would cause voltage stability issues under peak conditions, and a contingency at Nepean TS is projected to become a load security concern by 2029 in the winter if the electrification load materializes are projected.

To meet increasing demand and improve reliability, a new transformer station and an additional 230 kV transmission circuit are required. A preferred option has been identified to connect a new "Kanata North" station to C3S from Chats Falls TS and a new 230 kV circuit from Merivale TS, potentially achieved by rebuilding M32S or C7BM. This not only adds transformation capacity but also helps relieve pressure at Kanata MTS and South March TS while supporting future growth at nearby stations like Marchwood and Bridlewood.

A key component of the recommended solution is the development of a switching station in the area. The switching station will serve as a central hub, enabling better contingency response, operational flexibility, and future expansion potential, including the ability to connect additional infrastructure or circuits as system needs evolve. Consistently highlighted during public engagement, the switching station responds directly to local priorities around improving resiliency and reliability. Strategically, it also positions the system to accommodate future upgrades, including a potential second connection to Chats Falls or integration with a broader 230 kV network, depending on outcomes from the East Bulk Study.

While large-scale non-wires alternatives such as wind, solar, and nuclear were considered, they were found to be potentially economically practical but technically infeasible for the identified needs. A combination of a renewable resource and a BESS requires a substantial amount of land. However, this approach does not address station capacity needs. While it may provide energy to support load growth, the electricity is still constrained by the capacity of the station's transformers. As a result, new transformation stations are still required. However, with consideration of system benefits (i.e. avoided provincial capacity and energy), it is *possible* that these provide ratepayer value, though a larger bulk system study is needed to inform where to optimally place utility-scale resources to address provincial needs.

A proposed BESS project from the LT1 procurement—originally intended for another municipality—has been relocated to the Kanata-Stittsville area, where it can deliver greater grid benefit by discharging during peak periods and improving load-serving capability. This means that the Kanata-Stittsville area will be reinforced with both wires and non-wires solutions.

In summary, the recommended plan for Kanata-Stittsville includes:

A new transformer station north of the existing Kanata MTS,

A new 230 kV transmission line from Merivale TS, 18km

Connection to the existing C3S line,

A strategically located switching station,

Station upgrades at South March TS, and

A second supply to Nepean TS

Together, these elements form a resilient and scalable infrastructure solution that addresses near-term needs while establishing a strong foundation for long-term system performance.

Figure 27 | Kanata-Stittsville Recommendations

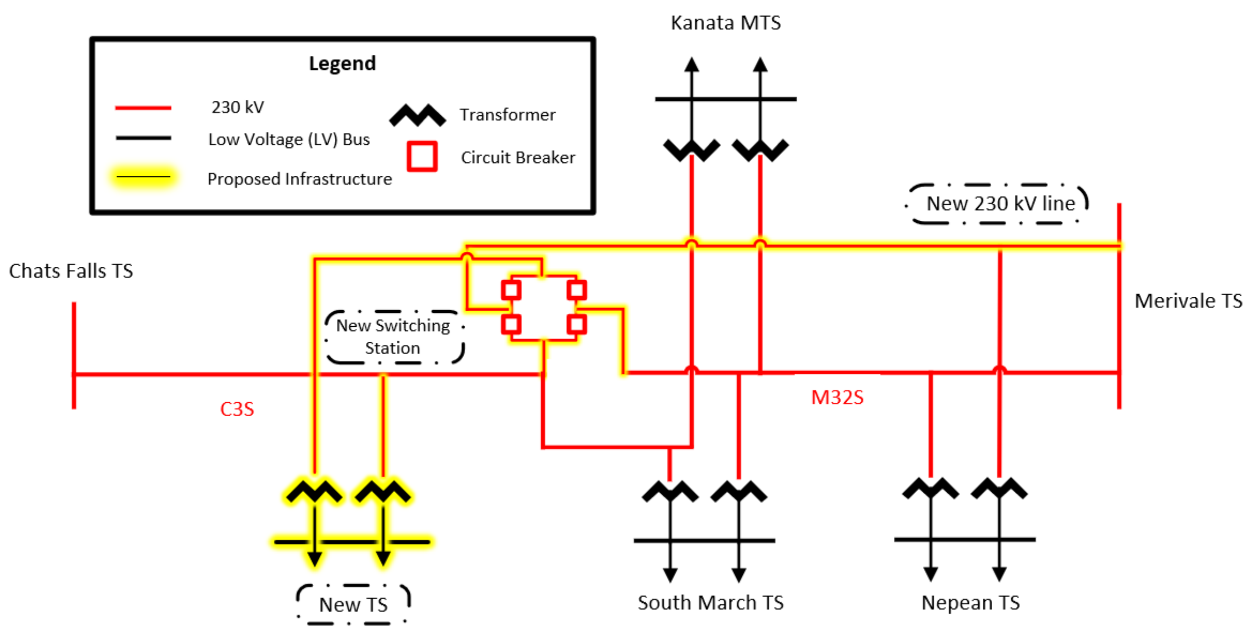


Table 8 | Wires Options for Kanata-Stittsville Subsystem

#	Description	High Level Planning Cost Estimate[5]
1	New 230 kV circuit to connect to the new station and Nepean TS from Merivale TS. The new station will tap to C3S	$185M+$45M
2	New 230 kV circuit from Merivale TS to switching station at South March TS. Nepean TS becomes double supply, all other stations connect to the switching station including a new station	$250M+$45M
3	Station transfer Kanata MTS to new station	$5-10M
4	Station transfer South March TS to new station	$0-5M
5	Station upgrade at South March TS	$40M

[5] All cost estimates are capital cost values

7.4 Options and Recommendations for the Core East Subsystem

7.4.1 Core East Subsystem – Pocket 1

Capacity needs in Pocket 1—especially at Lisgar TS, Carling TS, and Nepean Epworth MTS—are projected to emerge within five years and intensify during winter. Demand at Lisgar and Carling is expected to exceed LTRs by 30–40 MW, requiring a stepwise approach across the short, medium, and long term.

Near-term relief could come from transferring load to Nepean Epworth MTS, which is connected to Merivale TS, where about 15 MW of spare capacity is available. While Slater TS also has capacity, only Lisgar TS is a feasible candidate for transfers due to the lack of distribution ties.

Station upgrades offer another path:

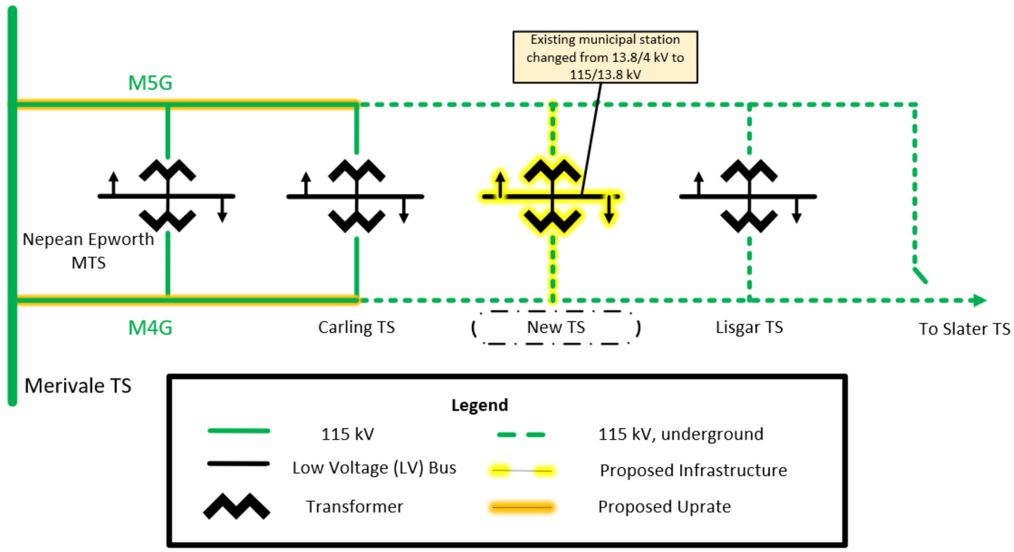
- At Carling TS, an upgrade could mitigate low-voltage limitations.
- At Lisgar TS, replacing transformer T2 and associated equipment could add ~45 MW.

Other options, such as relocating Carling TS to V12M and F10MV, were found to offer limited benefit due to space constraints and their inability to add new capacity.

Building a new transformer station and transmission lines in this dense area is technically viable but faces steep costs and logistical challenges. However, a promising alternative is to convert Bronson Station from a municipal distribution station to a 115 kV DESN station. Located between Carling TS and Lisgar TS along the M4G/M5G corridor, Bronson MTS could relieve adjacent stations via load transfers and by servicing future load. It is situated in a convenient location close to the 115 kV transmission lines but will require new transformers and significant cable connections. The approximate cost for this conversion is $65 million. This option would require uprating M4G and M5G to address thermal constraints.

Given the densely populated area, wind and/or solar options were screened out as feasible NWA's given the size of the need, and the land-use requirement of the facility that would be required to serve this need. However, A BESS-only NWA was assessed as a possible option, though it would only provide transmission deferral value through deferring investment by 2 years, but at a significant cost of $3.8 to 4.2B. Accordingly, the most practical solution for Pocket 1 is a combination of station expansions, targeted load transfers, and development of Bronson MTS.

Figure 28 | Core East Pocket 1 Recommendations



7.4.2 Core East Subsystem – Pocket 2

Pocket 2 encompasses much of Ottawa's downtown and is supplied by a tightly integrated 115 kV network. Nearly all stations are forecast to reach capacity within 20 years, particularly in winter, posing a major long-term planning challenge.

Given the urban density, expanding the network—especially with 230 kV infrastructure—is technically complex and expensive. Required upgrades at Hawthorne TS, the use of underground cables, and land constraints for new stations further limit this pathway.

Instead, the focus is on maximizing existing infrastructure and pursuing targeted improvements while managing the pace of demand growth. Near-term investments include:

- King Edward TS: ~35 MW through breaker and cable upgrades
- Albion TS: potential expansion through transformer upgrades

The upcoming LAPS will help identify eDSM opportunities, including energy efficiency, demand response, and behind-the-meter solar and storage measures. Demand reduction remains the most effective way to delay or avoid large-scale upgrades—every deferred megawatt reduces long-term cost and complexity.

A medium-term solution is to convert Cyrville TS to 230 kV using circuits D5A and a new A25, which would alleviate 115 kV constraints and allow for relocation of Cyrville MT's transformers to Moulton TS, upgrading both stations in the process.

An ongoing project at Merivale will add a third autotransformer by 2029 which will help support growth in the medium/longer term. It is possible to install a fourth autotransformer in the future, but beyond that, capital investments exceeding $1 billion could be unavoidable if demand continues rising.

Build a new 115kV Transformer Station east of Carling TS by converting existing Bronson distribution station

Connect the new Transformer Station to existing 115 kV transmission circuits M4G and M5G

Uprate sections of M4G and M5G, 12km

Proceed with station upgrades at Albion TS, Carling TS, Lisgar TS, Russel TS, King Edward TS

Proceed with distribution load transfers at Riverdale TS, Nepean Epworth MTS, Ellwood MTS

Convert Cyrville MTS from 115kV to 230kV station

Repurpose Cyrville MTS transformers at Moulton TS for station rating increase

Leverage insights from the LAPS to help slow demand growth in the downtown core, while continuing to monitor load trends between planning cycles

Figure 29 | Core East Recommendations

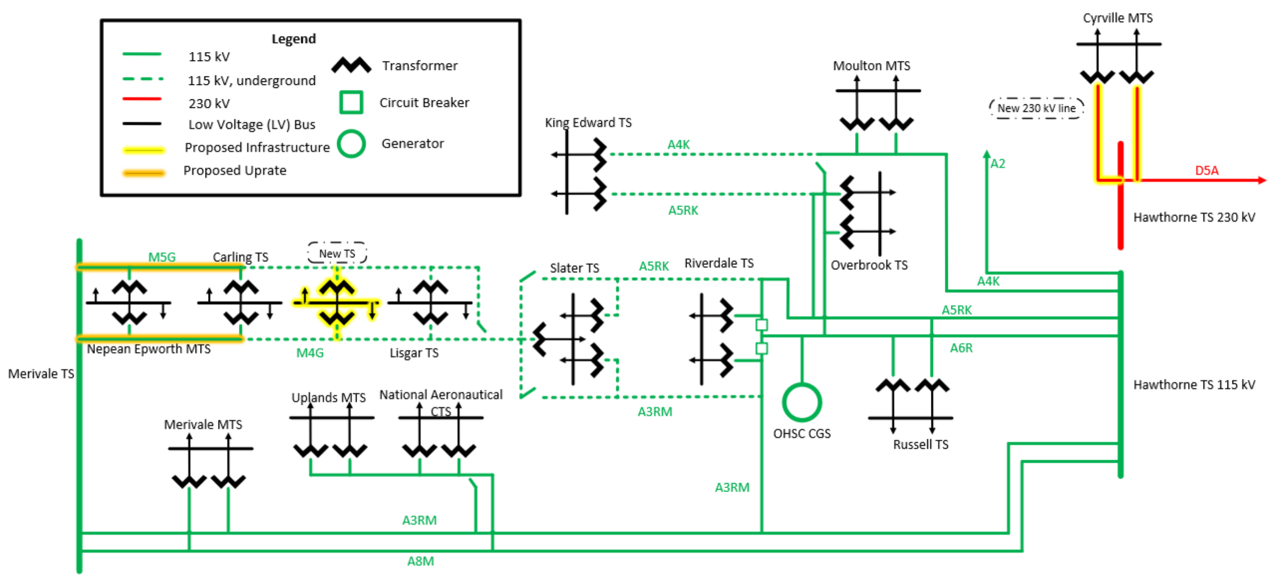


Table 9 | Wires Options for Core East Subsystem

#	Description	High Level Planning Cost Estimate[6]
1	New 115kV Transformer Station Connected to M5G and M4G, Convert Existing Bronson Station	$35M + $65M
2	Connect Carling TS to V12M and F10MV	$30M
3	Convert Cyrville TS to 230kV	$40M
4	Distribution Load Transfers – Hydro Ottawa/Hydro One Distribution	$0-5M per station

7.5 Options and Recommendations for the Core West Subsystem

7.5.1 Core West Subsystem – Pocket 1

For the area supplied by circuits S7M, W6CS, and E34M, three near-term station capacity needs have been identified—Bridlewood MTS, Marchwood MTS, and Fallowfield MTS—with three more expected in the long term.

Bridlewood MTS and Marchwood MTS are located in or near the Kanata-Stittsville area. Addressing their needs should align with broader upgrades planned for Kanata-Stittsville. As described in Section 7.3, the recommended approach for Kanata-Stittsville involves building a new 230 kV transformer station, supplied by a new 230 kV circuit from Merivale TS, which would also provide a secondary supply to Nepean TS. Since South March TS and Kanata TS will also benefit from additional capacity in the area, to address Bridlewood and Marchwood's capacity needs in the short term, the Working Group recommends implementing distribution load transfers—an efficient and cost-effective solution compared to building or upgrading stations.

Fallowfield MTS requires additional consideration. Several factors shape the recommendation:

- Circuit breakers were upgraded in 2018.
- Part of the S7M line has already been refurbished for future 230 kV operation.
- Load growth is expected in the area immediately north of the station, particularly for 28 kV distribution supply.

Based on these factors, multiple options were considered: upgrading the station, transferring load to Cambrian MTS, or transferring to a future new station. The Working Group recommends a phased approach:

- Short term: Transfer load to Cambrian MTS.

[6] All cost estimates are capital cost values

- Medium term: Shift load to a new station north of Fallowfield MTS.
- Long term: Upgrade Fallowfield MTS to 230 kV (requires conversion of S7M to 230 kV operation).

A separate thermal overload concern was identified in Pocket 1 during a contingency involving the loss of E34M and the transfer of Cambrian MTS load onto S7M. To address this long-term need, the Working Group assessed both wires and non-wires options and views the voltage conversion of S7M and the stations in the area to 230 kV would offer several benefits:

- Converting stations to 230 kV would result in increased station capacity to support future load growth.
- Shifting load from the 115 kV system to the 230 kV system would preserve load growth capacity for other stations, particularly those in densely built areas like the downtown core, where expansion is difficult.
- A new circuit could provide a second supply to Terry Fox MTS, which, like Nepean TS, currently relies on a single supply circuit with measures in place to allow for faster restoration.

To manage costs and avoid asset stranding, the S7M conversion should be implemented in phases. The Working Group recommends converting only the southern section of S7M, maintaining the northern portion that supplies Bridlewood MTS and Marchwood MTS and retaining its open-point connection to C7BM to preserve to ensure the 115kV generation connections northwest of the city are maintained.

The first step in the transition involves constructing a new 230 kV circuit from Merivale TS westward to the new station, which could later be extended to supply Terry Fox MTS. Station upgrades would follow at Manotick DS, Richmond South MTS, and Cambrian MTS, with the circuit initially connecting at the S7M junction. Once complete, these upgrades will provide a second 230 kV source to key stations, significantly improving system resilience.

In the medium-term, thermal overload risks remain on the Merivale TS end of S7M during an E34M outage. Until the full conversion is completed, interim relief could be provided through non-wires alternatives and distribution load transfers from Cambrian MTS to the new station if demand rises quickly.

Finally, the Working Group reviewed the proposed Trail Road BESS battery project, announced under the LT1 procurement. While it will support overall grid resilience, it connects to E34M and would not relieve loading on S7M unless a direct connection is also established.

7.5.2 Core West Subsystem – Pocket 2

Two smaller stations in this pocket—Manordale MTS and Centrepoint MTS—are facing capacity constraints. Due to growing demand and specific large customer requests, there is a need for 28 kV distribution in the area. However, both stations currently operate at only 8 kV, making them unable to meet this requirement. As a result, a new transformer station is needed.

One option considered was redeveloping Manordale MTS as a DESN station, but this was deemed unfeasible due to space limitations at the site. The alternative is to construct a new station at a different location. While a final site has not yet been selected, Hydro Ottawa is actively evaluating several options and is responsible for determining the final location.

The northern portion of the system was found to have thermal overloads. The main stations contributing to this are Lincoln Heights TS and Woodroffe TS and are not forecast to reach their capacity until the winter in the long-term. Therefore, the most economical solution is to simply uprate the segments of cables identified.

Build a new 230kV Transformer Station west of Merivale TS

Build a new 230kV transmission line westwards from Merivale TS along existing corridor, 5 km

Connect the new Transformer Station to E34M and new transmission circuit

Uprate sections of M4G and M5G, 10km

Uprate sections of C7BM and F10MV, 8km

Incorporate BESS resulting from LT1 procurement to improve area's voltage and reliability

Figure 30 | Core West Recommendations

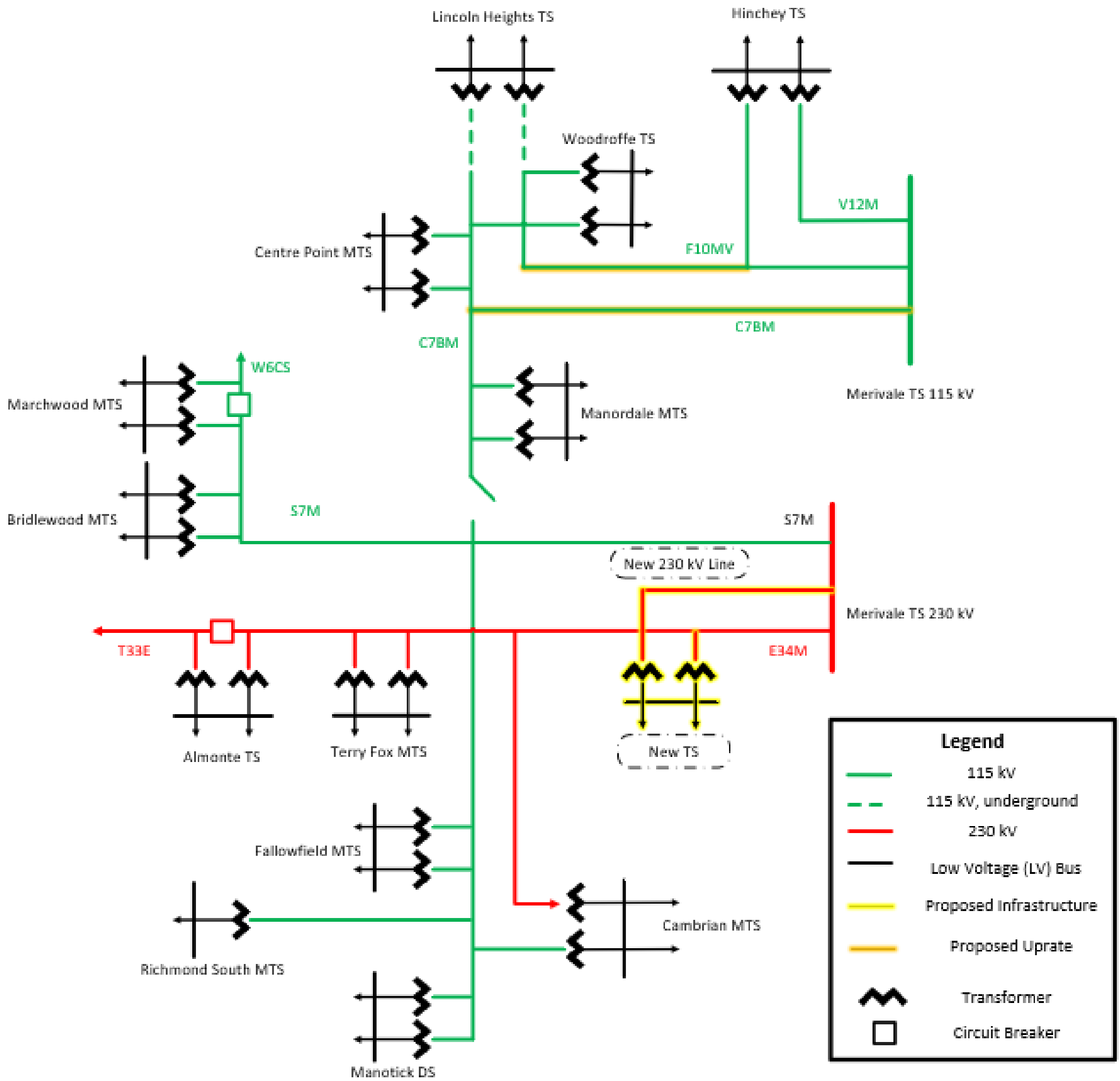


Table 10 | Wires Options for Core West Subsystem

#	Description	High Level Planning Cost Estimate[7]
1a	Fully Convert S7M to 230 kV	-
2a	New 230kV Circuit to S7M STR Junction, Convert Southern Portion of S7M to 230kV, Keep Existing 115kV S7M Connecting to W6CS	$100M
2b	New 230kV Circuit to Connect Terry Fox MTS and new Greenbank MTS	$90M
2c	New 230 kV Circuit to Terry Fox, Convert Southern Portion of S7M to 230 kV, Keep Existing 115 kV S7M Connecting to W6CS	$140M
3a	Fully uprate C7BM and F10MV	$50M
4a	Reconductor S7M, keep 115kV	$15M
5	Distribution Load Transfers – Hydro Ottawa/Hydro One Distribution	$0-5M per station

7.6 Options and Recommendations for the Core South Subsystem

Three stations in Core South—Limebank MTS, Greely DS, and Marionville DS—are forecast to exceed their long-term ratings (LTRs) within the next five years, requiring immediate action to address upcoming capacity shortfalls.

Given the scale and timing of these needs, station transfers and upgrades were the only solutions considered, as building a new station was deemed cost-prohibitive relative to projected demand outlook. In the near term, minor overloads at Limebank MTS can be addressed through distribution-level load transfers to Piperville MTS, which is scheduled for energization in 2026 and will be connected to the 230 kV L24A circuit. This transfer also reduces loading on the 115 kV system, contributing to better overall system balance.

For Marionville DS, the recommended action is to install a second transformer to increase capacity. At Greely DS, the proposed solution involves enabling supervisory control and data acquisition (SCADA) monitoring, allowing for an increase in respected transformer limits and improving station performance.

To meet load security requirements in Core South, the most effective strategy is the installation of a breaker between circuits L2M and M1R at Merivale TS. This change would ensure that a loss of both

[7] All cost estimates are capital cost values

circuits would only occur under a double contingency, which is significantly less likely and subject to a higher load rejection threshold of 600 MW.

For medium-term System Capacity needs, three main options were assessed:

1. Uprating segments of circuit L2M between Merivale TS and Limebank MTS to avoid thermal overloads.
2. Converting Limebank MTS to a 115 kV DESN, supplied by M1R and L2M. While Limebank's projected peak load remains below 150 MW (permissible under single contingency criteria), the station has four transformers, and adding a second supply would significantly improve system reliability.
3. A long-term option involves converting Limebank MTS to a 230 kV DESN, supplied by two new circuits from the St. Lawrence region. However, this would require comprehensive bulk system studies to determine the feasibility of extending 230 kV infrastructure from the St. Lawrence area to Merivale TS. As such, this remains a long-term vision rather than a near- or medium-term solution.

Build a new breaker position at Merivale TS and separate circuits M1R and L2M

Proceed with station upgrades at Greely DS and Marionville DS

Distribution load transfer from Limebank TS to Piperville TS

Figure 31 | Core South Recommendations

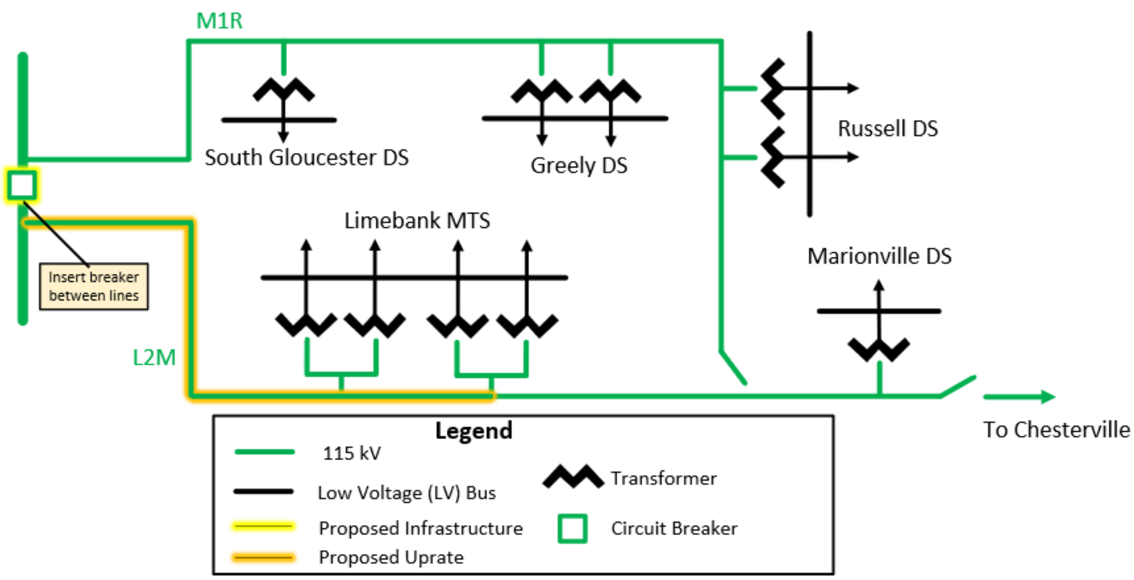


Table 11 | Wires Options for Core South Subsystem

#	Description	High Level Planning Cost Estimate[8]
1	New breaker position at Merivale TS to separate L2M and M1R	$30M
2	Uprate segments of L2M from Merivale TS to Limebank MTS	$25M
3	Convert Limebank MTS to 115 kV DESN	N/A
4	Convert Limebank MTS to 230 kV DESN	N/A
5	Station transfers	$5M
6	Station upgrades	$12M+$3M

[8] All cost estimates are capital cost values

7.7 Long-Term Considerations

7.7.1 Kanata-Stitsville Subsystem

This subsystem, defined by the 230 kV transmission circuits and transformer stations that supply the Kanata-Stittsville area, is experiencing a period of rapid economic development, which will require accessible and reliable electricity. A number of investments—including a new transformer station, transmission circuit, switching station, and potential BESS site—have been recommended in this report to help meet these goals. These investments are designed to increase both station and System Capacity, improve resiliency via the switching station, and enhance power quality and flexibility through the proposed BESS project.

Once these investments are implemented, the Kanata-Stittsville Subsystem will consist of one transmission circuit from the Chats Falls area (C3S), two circuits from Merivale TS (including M32S and the proposed new circuit), four transformer stations to supply power, and a strategically located BESS which can help meet peak demand and support voltage stability in the area.

The long-term vision for this subsystem continues to reinforce each component. The new circuit and switching station significantly improve supply from the Merivale side but do not yet enhance the supply path from Chats Falls. As such, a future consideration is to extend the new transmission circuit to Chats Falls TS, which would increase the LMC of the subsystem and provide a second path for hydroelectric generation to reach Ottawa loads. In general, the growth projected by demand forecasts will require reinforcement of Ottawa's western supply, which is being explored under the East Bulk Plan. One promising option includes the development of a new autotransformer station—similar to Merivale TS and Hawthorne TS—in western Ottawa. The proposed switching station has been recommended with this potential in mind and is being designed to accommodate a connection to this new substation, further strengthening the capability and flexibility of the Kanata-Stittsville system.

If demand grows at a faster pace than forecast—particularly due to unforeseen industrial or large commercial developments—a second transformer station beyond what is currently planned (e.g., in addition to Kanata North MTS) may be required. A more detailed assessment of the Kanata study area will help clarify the actual capacity available within this new configuration and determine the timing and scope of future infrastructure.

7.7.2 Core East Subsystem

This subsystem is defined by the 115 kV network that supplies most of Ottawa's downtown core. Given the complexity and limited physical space for new infrastructure in the downtown area, the focus of this plan is to maximize existing assets and strategically pursue upgrades to avoid large-scale overhauls. This plan recommends increasing station capacity by upgrading Carling TS, Lisgar TS, and Riverdale TS, while also gaining additional capacity through the conversion of Bronson TS from a distribution station to a transmission supply point, and converting Cyrville MTS from 115 kV to 230 kV.

The Working Group recommends implementation of the additional cost-effective eDSM potential that will be identified in the LAPS, which promote non-wires alternatives to mitigate load growth, including energy efficiency programs, distributed energy resources (DERs), and demand response initiatives. Additional optimization is possible by leveraging Slater TS, which is centrally located and supplied by three independent circuits. Slater's robust configuration makes it a strong candidate for load transfers, and future development should be encouraged near this area to capitalize on its reliability and existing capacity.

Monitoring the evolution of winter peak demand will be critical. If these trends materialize as expected, a major decision will be required, as the 115 kV network alone cannot accommodate long-term growth in its current configuration. One response may involve installing a fourth autotransformer at Merivale TS to support increasing inter-pocket transfers. More broadly, planners will need to decide between:

1. Introducing a new 230 kV supply path into the downtown core;
2. Converting select segments of the 115 kV system to 230 kV; or
3. Build new transmissions lines into the downtown core.

All options would ultimately require significant expansion work at Hawthorne TS, which serves as a key transmission node for the eastern subsystem.

The long-term vision for the broader region anticipates that most expansion will occur west of Ottawa, reducing the need for major downtown build-outs. With the implementation of the upgrades and strategies outlined in this plan, the Core East subsystem will largely be able to rely on enhanced operational efficiency and, at most, require one to two new transformation stations to support long-term growth.

7.7.3 Core West Subsystem

Following the uprate of C7BM and F10MV the rest of the stations in Pocket 2 of the Core West subsystem will be able to grow to their LTR which is sufficient for the 20-year demand forecast. The area will also have a new 230kV transformer station that will help offload the smaller stations in the area. The long-term vision for this subsystem is to expand the 230kV transmission circuit west. By doing so, it allows for multiple successive investments. These include providing a second supply to Terry Fox MTS, converting S7M to 230kV, and providing a second supply to Cambrian MTS as well. Further, depending on the outcomes of the Bulk Study, a potential 230kV autotransformer station will allow for expansion in this area to meet growing demand.

7.7.4 Core South Subsystem

The future of this subsystem will depend on the outcome of the East Bulk study. A potential 230kV transmission line from St. Lawrence presents to opportunity to convert the entire pocket.

The load at Limebank MTS is to be monitored and will eventually require a second supply. The circuits will also need to be uprated as the load grows.

A new auto-transformer station in the west of Ottawa would also impact how this system is planned and depend again on the East Bulk Study.

7.8 Summary of Recommended Actions and Next Steps

The Working Group recommends the actions summarized in **Table 12** to meet identified needs in the Ottawa Area Sub-Region IRRP.

Table 12 | Summary of the Near-Term Plan for the Ottawa Area Sub-Region IRRP

Need Type	Affected Element(s)	Recommendation	High Level Planning Cost Estimate[9]
System Capacity (Transformation)	Core East Pocket 1	Build new Transformer Station by converting existing Distribution Station. Connect to M4G and M5G. Interim station name: Bronson MTS.	$65M
System Capacity (Thermal Overload)	M4G, M5G	Uprate portions of M5G and M4G.	$35M
System Capacity (Transformation)	Core East Pocket 2 A5RK, A6R, A4RK, A3RM, A8M, A2	Convert Cyrville MTS (115kV) to 230kV thereby preserving capacity on autotransformers for growth on the 115kV downtown system. Pursue eDSM program opportunities as part of LAPS to reduce demand and delay large-scale infrastructure upgrades.	$75M TBD
Station Capacity	Carling TS	Upgrade secondary cables to increase station rating. Distribution load transfer to new Bronson MTS.	$40M $0-5M
Station Capacity	Lisgar TS	Increase station rating by upgrading limiting LV element	$20M
Station Capacity	Riverdale TS	Distribution load transfer to new Bronson MTS.	$0-5M
Station Capacity	Nepean Epworth MTS	Distribution load transfer to Merivale MTS.	$100K
Station Capacity	King Edward TS	Upgrade cables to increase station rating.	$40M

[9] All cost estimates are capital cost values

Need Type	Affected Element(s)	Recommendation	High Level Planning Cost Estimate[9]
Station Capacity	Cyrville MTS	Station voltage conversion from 115kV to 230kV to increase station rating.	$75M
Station Capacity	Moulton MTS	Repurpose 115kV transformers from Cyrville MTS voltage conversion to increase station rating. Estimate does not consider any circuit upgrade that may be required.	$5M
Station Capacity	Ellwood MTS	Distribution load transfer to Albion TS.	$0-5M
System Capacity (Transformation, Voltage Stability)	Kanata-Stittsville	Build a new Transformer Station north of existing stations. Connect to C3S and new transmission line from Merivale TS. Interim station name: Kanata North MTS. Build a new 230kV transmission line from Merivale TS by rebuilding C7BM corridor, connecting Nepean TS and the new Kanata North MTS. Build a switching station that connects existing and new 230kV stations to improve resiliency and flexibility.	$45M $185M $65M
Load Security	Nepean TS	Provide second supply to Nepean TS via new transmission circuit from Merivale TS. Same circuit that is being built to supply new Kanata North MTS.	$5M
Station Capacity	Kanata MTS Marchwood MTS	Distribution load transfer to new Kanata North MTS.	$6-8M
End-of-Life Station Capacity	South March TS	Upgrade transformers at South March TS to increase station rating.	$40M
System Capacity (Thermal Overload)	Core West Pocket 1 F10MV, C7BM	Uprate portions of C7BM and F10MV.	$50M

Need Type	Affected Element(s)	Recommendation	High Level Planning Cost Estimate[9]
System Capacity (Transformation)	Core West Pocket 2	Build a new Transformer Station to meet demand growth and need for 28kV supply west of Merivale TS. Interim station name: Greenbank MTS.	$40M
		Build new 230kV transmission line from Merivale TS to supply new Greenbank MTS.	$40M
Station Capacity	Centrepoint MTS Fallowfield MTS Manordale MTS	Distribution load transfer to new Greenbank MTS.	$0-5M
Station Capacity	Bridlewood MTS	Distribution load transfer to Terry Fox MTS.	$0-2M
Load Security	Core South L2M, M1R	Install a new breaker at Merivale TS and separate L2M and M1R.	$30M
Station Capacity	Marionville DS	Install a second transformer to increase station rating.	$12M
Station Capacity	Greely DS	Install SCADA transformer monitoring to increase station rating.	$3M
Station Capacity	Limebank MTS	Distribution load transfer to Piperville MTS.	$5M
Planning	N/A	Working Group to produce Adaptive Pathways documents for each subsystem following the publishing of the IRRP.	

8. Community and Sector Engagement

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

8.1 Engagement Principles

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

Figure 32 | The IESO's Engagement Principles

8.2 Engagement Tactics

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

- Leveraging the **Ottawa Area Sub-Region engagement webpage** to share information including engagement opportunities, meeting materials, input received and the IESO's response to feedback;

- Leading targeted discussions with key municipal staff to help inform the engagement approach for this planning cycle;
- Hosting public webinars at major junctions in the plan development to share plan details, understand feedback and answer questions, and;
- Providing written updates through email and IESO's weekly Bulletin updates to all subscribers.

8.3 Engagement Approach

Four public engagement webinars were held at major stages during the Scoping and IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. Unique to the IRRP was a Local Achievable Potential Study (LAPS) for the Ottawa Area taking place in parallel. Feedback on the Local Achievable Potential Study was solicited during the webinar on "Needs and Potential Wire Options."

Public engagement webinars were attended by several representatives from the City of Ottawa, community representatives, businesses, Indigenous communities, and other stakeholders with an identified interest, and written feedback was collected following a comment period after each webinar. The four stages of engagement at which input was invited were:

1. The draft scoping outcome assessment report to share the planning approach before delving into the full IRRP study.
2. The draft engagement plan, electricity demand forecast, and early identified needs – to set the foundation of this planning work.
3. The defined electricity needs for the region and potential wire options to meet the identified needs, as well as
4. The analysis of all feasible wire and non-wire options and draft IRRP recommendations.

Comments received during the development of the IRRP primarily focused on:

- Accounting for growth and economic development projects across the region;
- Ensuring climate impacts are accounted for throughout the development of the IRRP, and;
- Exploring alternative solutions, such as non-wire options, to meeting the area's electricity needs.

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

8.3.1 Scoping Assessment

As part of the 2020 Ottawa Sub-Region IRRP, the Technical Working Group recommended to monitor the City of Ottawa's Energy Evolution mandate in future planning cycles. During the monitoring, the Technical Working Group recommended to advance the planning cycle. When regional planning kicked off, the draft 2023 Scoping Assessment Outcome Report recommended focused discussions to take place with the City of Ottawa, the local distribution companies and the IESO on the impacts of Energy Evolution and GHG emission targets on the demand forecast.

Once the draft report was completed, an email communication was sent to all subscribers of the Greater Ottawa Region, including municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and encourage participation on the Greater Ottawa Scoping Assessment Report finalization. A public webinar was held in February 2023 to provide an overview of the regional electricity planning process, the draft report and proposed approach.

Feedback received during this milestone encouraged the IESO to obtain data from large customers electrification plans and to review opportunities for distributed energy resources to reduce electricity demand. The Technical Working Group confirmed a process to collect input from municipalities, businesses, Indigenous communities and other interested parties will take place in the next milestone. The Technical Working Group also committed to explore opportunities for distributed energy resources and will enhance engagement to increase opportunities for input. The final Scoping Assessment was posted in March 2023, identifying the need for a coordinated regional planning approach for the Ottawa Area.

8.3.2 Demand Forecast

Following finalizing the Scoping Assessment, the Technical Working Group began the development of Ottawa's electricity demand forecast. IRRP recommendations are typically driven by the Reference Demand Forecast, which includes firm loads (current and planned), organic growth, residential, electrification and energy plans, and industrial growth. The Technical Working Group sought input from the City of Ottawa and large electricity customers (including school boards). The reference forecast assumes most likely electrification adoption rates based on current policies and includes eDSM forecasts based on provincial and federal policies, as well as the impact of existing and expected DERs in Ottawa.

In parallel, the Technical Working Group determined the need to develop a High Growth Demand Forecast to capture growth and trends that are less certain such as full decarbonization of the city or large-scale customer connections. To achieve this, the City of Ottawa, the local distribution companies and the IESO participated in several focused discussions to capture the effects of economic development, electrification and decarbonization in the city. Hydro One Transmission and Enbridge Gas Inc. participated in these "Decarbonization Focus Group" meetings as observers. In 2023 the IESO piloted an approach in both the Toronto and Ottawa IRRPs, to engage Enbridge Gas Inc. throughout the demand forecasting process as an observer. The observer's role was limited to subject matter experts providing feedback on the discussions where applicable. The purpose of the "Decarbonization Focus Group" was to determine a high growth demand forecast for the Ottawa Area that reflects the full decarbonization of the city.

During this time, six meetings from March to December 2023 took place within the Decarbonization Focus Group to obtain insights including shared experience with decarbonization. Key discussion items raised included the importance of visibility into planned major energy efficiency projects and understanding how to share updates on when this load is materializing. After gathering all insights, Hydro Ottawa engaged a third-party consultant to capture the effects of electrification and decarbonization into five forecasts. The reference and high growth forecast scenarios were chosen and all forecasts were shared through the launch of a broader public engagement initiative. Communications to IESO subscribers of the Greater Ottawa Region ensured all interested parties were made aware of the opportunity for input.

During this milestone, key information shared was that the electricity demand is growing significantly in the Ottawa area with demand estimated to grow by 33% in the winter and 166% in the summer by 2043. The primary drivers of growth are economic growth and decarbonization initiatives which promote the intensification of electricity use, resulting in a substantial demand increase, particularly in the winter. The reference forecast will be used to drive recommended solutions, however the Technical Working Group will identify options for long-term electricity needs and high-growth scenarios, refining these options in future planning cycles and activating them as growth occurs.

Based on the feedback through this engagement initiative, a key priority was to ensure the IRRP considered climate impacts into the demand forecast and incorporated resiliency into recommended actions. The Technical Working Group ensures the forecast reflects extreme weather conditions in various scenarios, which includes the system's ability to respond to disturbances, and committed to ongoing discussions about resiliency throughout plan development. Additionally, feedback was centred around ensuring alternative solutions, such as non-wire options, are explored. The Technical Working Group committed to evaluating wire and non-wire options and sharing the analysis as planning work advances. Additionally, the IESO informed the public that details about the Local Achievable Potential Study underway for the Ottawa Area will be shared in future engagements.

8.3.3 Electricity Needs and Potential Wire Options

During this milestone, the Technical Working Group identified significant station capacity, System Capacity, end-of-life, load restoration and load security needs throughout the Ottawa area, with several of these needs emerging in the near-term. Therefore, the Technical Working Group determined it was necessary to prioritize options that met near- and medium-term needs. Given the magnitude and timing of the near- and medium-term needs, potential wire options were developed and shared with the community at this milestone with a commitment to presenting a comprehensive analysis for all feasible wire and non-wire options later.

Feedback at this stage of the engagement sought to further clarify the options analysis stage of the IRRP, particularly if wire and non-wire options would be considered as alternatives to each other. Additionally, feedback received urged for resiliency to be considered when finding options to meet needs. The Technical Working Group confirmed wire and non-wire options, or any combination of both, will be evaluated to meet the area's needs. Additionally, the Technical Working Group acknowledges the importance of resiliency and will consider this in the detailed options analysis.

Feedback was also solicited for the Local Achievable Potential Study and the community recommended to broaden the scope of the study. The project team for the local APS confirmed several considerations raised, including leveraging Dunsky's 2022 provincial DER potential study, inclusion of thermal storage, consideration of decreasing costs of technologies overtime and more were incorporated into the report. The IESO also clarified that front-of-meter DER was being considered outside of the Local Achievable Potential Study in the IRRP and explained why vehicle-to-grid technology was excluded. Engagement with the City of Ottawa and the Decarbonization Focus Group were undertaken as part of this milestone.

8.3.4 Options Analysis and Draft Recommendations

During this milestone, the Technical Working Group shared the options analysis for all feasible wire and non-wire options and shared the draft recommendations. The draft recommendations included two new transmission lines within existing corridors, two new stations and two significant upgrades to existing stations. Informed by feedback about resiliency, the draft recommendations also include a switching station to improve transmission reliability by rerouting power during outages or maintenance, minimizing disruptions and enhancing grid flexibility.

The outreach strategy for this milestone included briefing various City of Ottawa staff as well as councillors whose riding is located where the draft recommendations are. A public engagement webinar was hosted to share the detailed analysis and draft recommendations, as well as an update on the Local Achievable Potential Study and a suite of Save on Energy programs available to Ottawa small businesses and residents. A touchpoint with the Decarbonization Focus Group was hosted to solicit feedback into the final IRRP.

8.4 Involving Municipalities in the Plan

Throughout the IRRP engagement, valuable feedback was received and incorporated into the final IRRP including:

- Enhancing webinar materials to share technical updates in a digestible manner.
- Undergoing a Local Achievable Potential Study which would study the potential of behind-the-meter options, including distributed energy resources, with the commitment to hosting a webinar later in Q3 to share the findings and next steps of the study.
- Including the City of Ottawa's Energy Evolution plans in the reference and high forecast scenarios.
- Incorporating information about economic development in Ottawa, particularly around the Kanata North area.
- Incorporating feedback around resiliency into the recommendation of a switching station to enhance transmission reliability.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities within the Ottawa Area Sub-Region throughout the development of the plan. This includes the communities of the Algonquins of Ontario, Pikwakanagan First Nation, and Métis Nation of Ontario Region 5.

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

9. Conclusion

This report documents an IRRP that has been carried out for the Ottawa Sub-Region of the OEB's Greater Ottawa planning region. The IRRP identifies electricity needs in the sub-region over the 20-year period from 2024-2043 and recommends preferred solutions to address near-term needs. The Working Group recommends Hydro One initiate a RIP. The Working Group will continue to provide support throughout the RIP process, and assist with any regulatory matters that may arise during plan implementation.

The IRRP also identifies actions to monitor, defer, and address remaining needs and to inform the next regional planning cycle. The Ottawa Sub-Region Working Group will continue to meet at regular intervals to monitor developments in the sub-region and track progress toward the plan deliverables. In the event that underlying assumptions change a new regional planning cycle may be initiated sooner than the OEB mandated five-year schedule.

GREATER OTTAWA REGIONAL INFRASTRUCTURE PLAN

REGIONAL INFRASTRUCTURE PLAN REPORT

GREATER OTTAWA

Regional Infrastructure Plan Report

Greater Ottawa

February 09, 2026

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Greater Ottawa Technical Working Group

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Disclaimer

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

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

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

Executive Summary

REGION	**Greater Ottawa** (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")

START DATE: August 18, 2025 **END DATE:** February 09, 2026

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process for the Greater Ottawa region, preceded by, the publication of Needs Assessment (NA) report in December 2022 by Hydro One which was triggered early due to high growth in the region followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) which were published in March 2023 and in July 2025 respectively, by the Independent Electricity System Operator (IESO).

Hydro One as the lead transmitter undertakes the development of a RIP with input from the Technical Working Group (TWG) for the region (includes representatives from Hydro One Transmission, IESO and LDCs and publishes a RIP report. The RIP report includes a discussion of all options and plans identified in earlier phases and recommends a preferred wires plan to address the near, medium, and long - term needs over a twenty-year study period.

The objectives and scope of the RIP are:

- A consolidated report of the needs and relevant wires plans to address near, and medium-term needs (2025-2034) identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identify any new need(s) over the 2025-2034 that may have emerged since previous planning phases. Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.
- Consideration of long-term needs identified in the Ottawa area sub-region IRRP, Bulk system studies or as identified by the TWG.

Since the IRRP study addressed needs only for the Ottawa Area Sub-region, the RIP as per TWG discussions developed a new load forecast for stations outside the IRRP scope and revised forecasts for certain stations. For the remaining stations, the IRRP load forecast was adopted for the RIP study, as no material changes were identified. During the IRRP stakeholder engagement process, IESO received municipal input on future load growth for consideration in the IRRP load forecast.

The list of major infrastructure investments recommended by the TWG in the region is given below. The needs include those previously identified in the NA and IRRP, as well as any new needs identified during the RIP phase, if any.

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Budgetary Cost ($M)
Asset Renewal Needs				
South March TS	Replacement of T1/T2 transformers with upgraded units based on asset conditions and capacity needs.	Hydro One	2029	$40M
Albion TS	Replacement of T1/T2 transformers with upgraded units based on asset condition and capacity needs.	Hydro One	2031	$60M
Nepean TS	Replacement of T3/T4 transformers based on asset condition	Hydro One	2034	$30M
S7M	Refurbishment of line section between Manotick JCT x Richmond South MTS and S7M 673N x Manordale JCT	Hydro One	2030	$5M
Station Capacity Needs				
South March TS	Replacement of T1/T2 transformers with upgraded units based on asset conditions and capacity needs.	Hydro One	2029	$40M
Carling TS	Replacement of limiting LV cables.	Hydro One	2030	$10M
Lisgar TS	Replacement of T2 transformer and LV cables/breakers - Greenfield	Hydro One	2034	$50M
	Replacement of T2 transformer and LV cables/breakers – In Situ	Hydro One	2031	$30M
King Edward TS	Replacement of LV cables and breakers.	Hydro One	2033	$20M

Cyrville MTS	Station voltage conversion from 115kV to 230kV to increase station rating and upgrade station transformation capacity.	Hydro One/ Hydro Ottawa	2029	$85M*
Moulton MTS	Relocate 50 MVA ,115kV transformers from Cyrville MTS after voltage conversion to increase station rating at Moulton TS.	Hydro Ottawa	2029	$5M
Bronson MTS	Build a new 115kV Transformer Station east of Carling TS by converting existing Bronson distribution station	Hydro One/ Hydro Ottawa	2031	$110M*
Greenbank MTS	Build new Transformer Station to meet demand growth and need for 28kV supply west of Merivale TS.	Hydro One/ Hydro Ottawa	2028	$100M*
Kanata North MTS	Build a new Transformer Station by connecting 230 kV C3S and new transmission line from South March TS	Hydro One/ Hydro Ottawa	2028	$100M*
Marionville DS	Install a second transformer to increase station rating.	Hydro One Dx	2029	$12M*
Greely DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2026	$2M*
Rockland DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2026	$2M*
Rockland East DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2027	$3M*

Transmission Line Capacity Needs				
M4G/M5G	Uprate Line section between Merivale TS x Carling TS	Hydro One	2030	$30M
L2M	Uprate line section between Merivale TS x Limebank JCT	Hydro One	2032	$30M
System Reliability, Operation and Load restoration Needs				
Kanata Area	Kanata Area Transmission Reinforcement	Hydro One	2033	$250M
Nepean TS – Load Security Criteria	Second 230 kV Supply to station	Hydro One	2032	$70M
M1R+L2M	Split Breaker position for M1R and L2M at Merivale TS	Hydro One	2032	$45M
East Ottawa Area	Supply to East Ottawa	Hydro One	2029-2030	$165M*

* These investment costs include associated distribution system costs.

Note:

a) The planned in-service dates are tentative and subject to change.
b) Costs are high-level planning estimates and actual costs may vary.

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1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of the Regional Planning Process. Hydro One as the lead transmitter undertakes the development of a RIP with input from the Technical Working Group (TWG) for the region (includes representatives from Hydro One Transmission, IESO and LDCs) and publishes a RIP report. The third cycle of the Regional Planning process for the Greater Ottawa region was initiated early due to high growth in the region with the publication of Needs Assessment (NA) and the report was published in December 2022 by Hydro One. This was followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) only for the Ottawa Sub-Region Area which were published in March 2023 and July 2025 respectively, by the Independent Electricity System Operator (IESO).

This RIP report is for the "Greater Ottawa Region" and includes the municipalities bordering the Ottawa River from Arnprior in the West to Hawkesbury in the East and North of County Road 43 (Highway 43) and includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

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

Table 1-1: Greater Ottawa region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Transmission)
2	Independent Electricity System Operator (IESO)
3	Hydro One Networks Inc. (Distribution)
4	Hydro Ottawa Limited
5	Hydro Hawkesbury
6	Renfrew Hydro Inc.
7	Hydro 2000 Inc.
8	Ottawa River Power Corp.

2. OBJECTIVES AND SCOPE OF REGIONAL INFRASTRUCTURE PLAN

This RIP report examines the needs in the Greater Ottawa region. Its objectives are to:

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs 2025-2034 identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2025-2034 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the Ottawa area sub-region IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

3.1 Overview

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

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

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

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

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

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

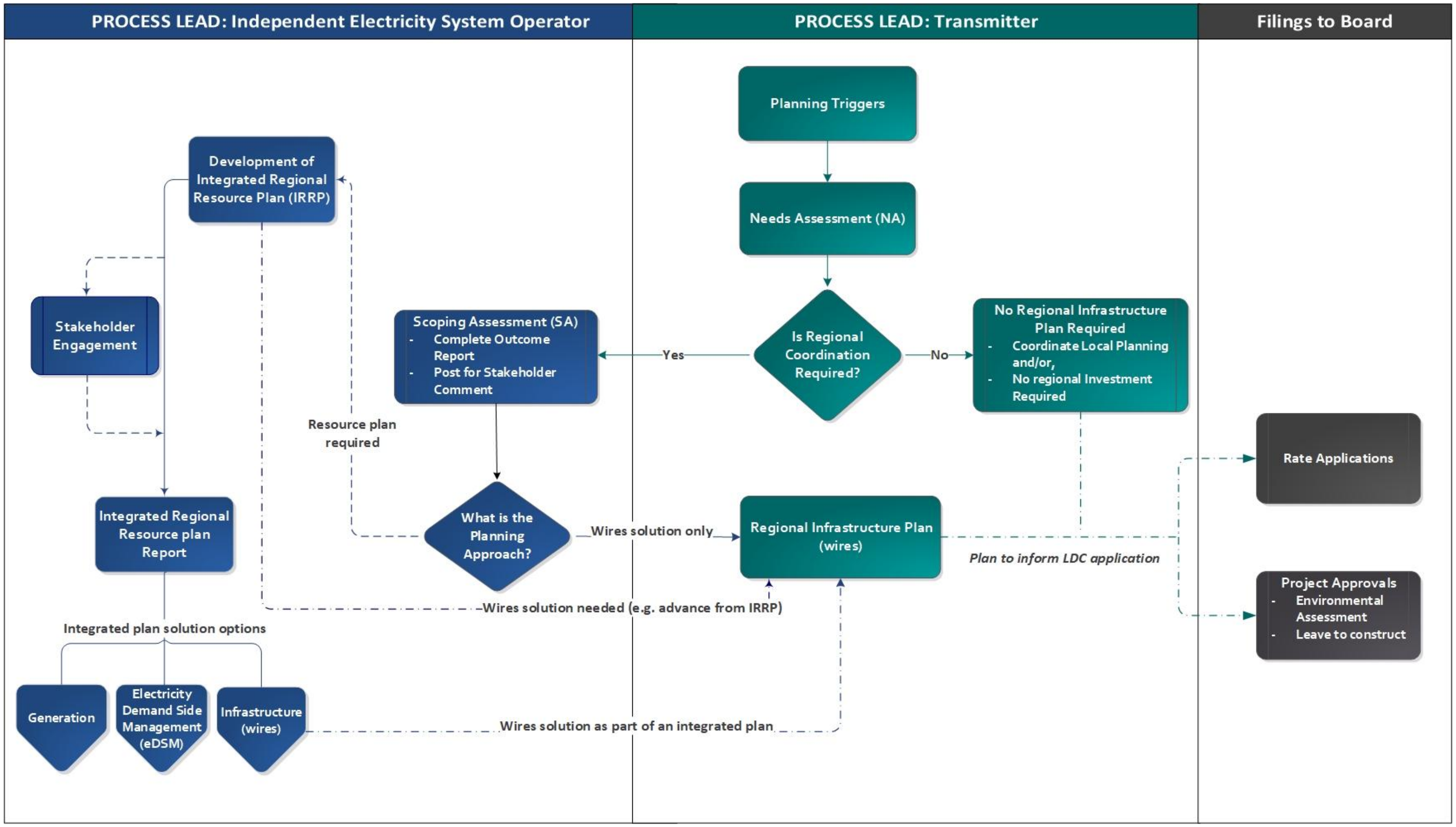
The primary purpose of the IRRP is to identify and assess both resource and wires options at a higher or macro level, but sufficient to permit a comparison of resource options vs. wire infrastructure to address the needs. Worth noting, the LDCs' eDSM targets as well as contracted DG plans provided by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

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

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

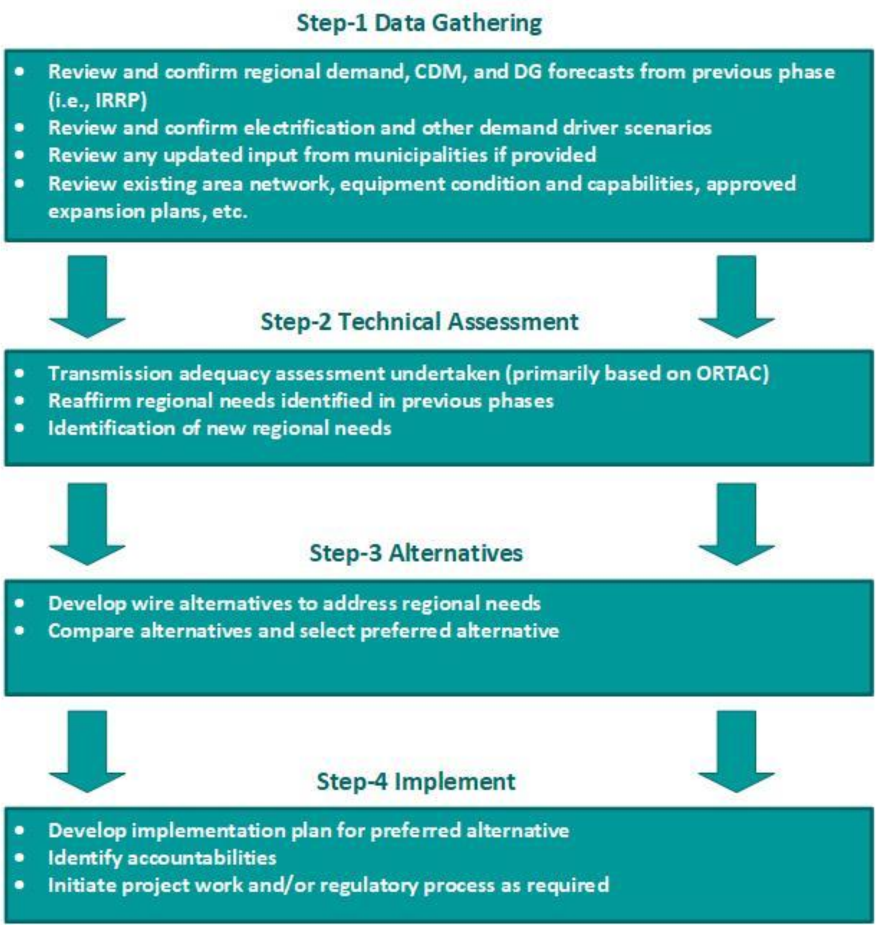
The various phases of Regional Planning Process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome are shown below in Figure 3-1.

Figure 3-1 Regional Planning Process Flowchart



3.2 Regional Infrastructure Plan Methodology

Figure 3-2 Regional Infrastructure Plan Methodology



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

3.2.1. Data Gathering:

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

- Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or eDSM programs. As agreed by TWG members, the load forecast from the Ottawa Area sub-region IRRP was used for this RIP with modifications to some stations and developed a load forecast for the outer Ottawa stations which were not covered in the IRRP.

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

3.2.2. Technical Assessment:

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

3.2.3. Alternative Development:

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

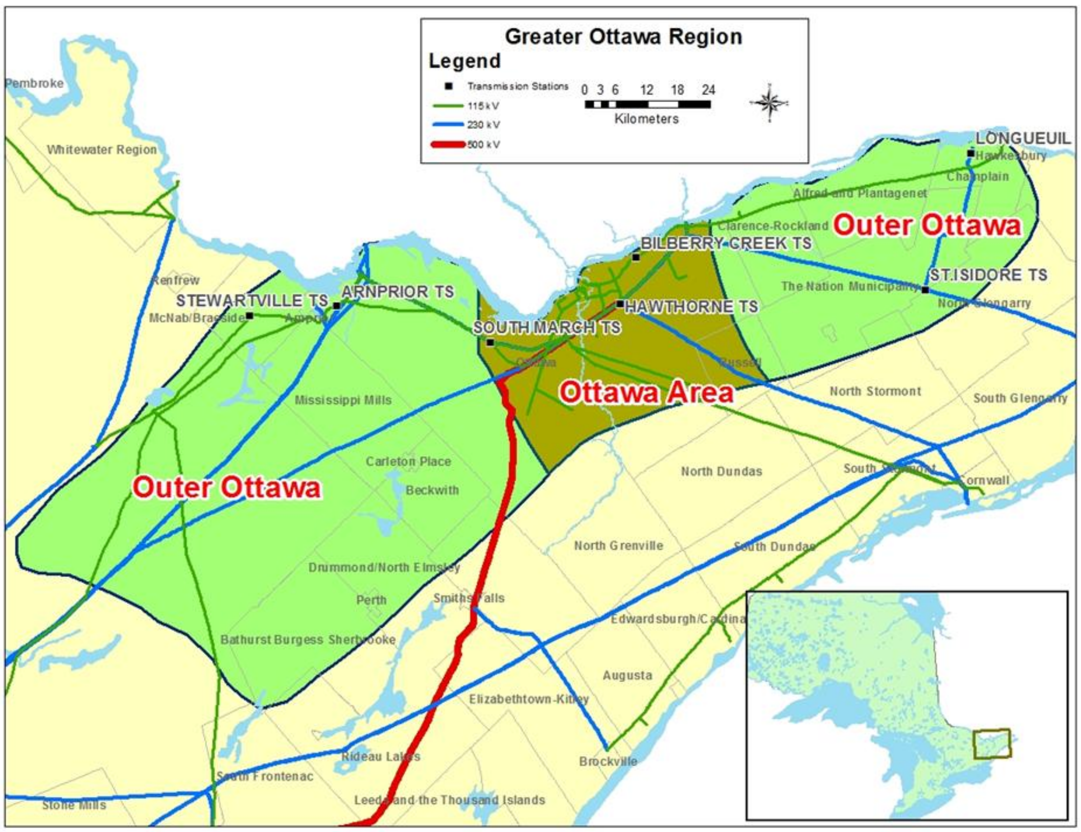
3.2.4. Implementation Plan:

The fourth and last step is the development of the implementation plan for the preferred alternative, identify accountabilities and initiate project work or obtain permissions from the Regulatory Commission if any.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Greater Ottawa Region covers the municipalities bordering the Ottawa River from Arnprior in the West to Hawkesbury in the East and North of County Road 43 (Highway 43). At the center of this region is the City of Ottawa. Electrical supply to the Region is provided from fifty-two (52) 230 kV and 115 kV step-down transformer stations. The boundaries of the Region are shown in Figure 4-1 below. The outer regions are referred to as the East and West Outer Ottawa sub-regions. The central region comprising of City of Ottawa is referred to as the Ottawa sub-region

Figure 4-1: Map of Greater Ottawa Regional Planning Area

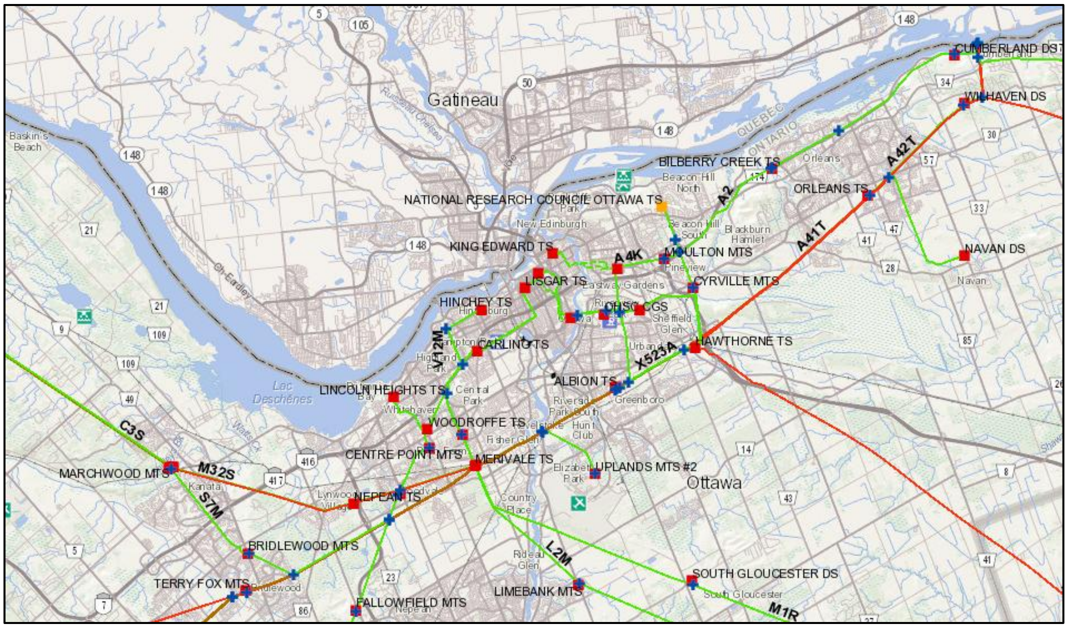


Bulk electrical supply to the Greater Ottawa Region is provided through the 500/230 kV Hawthorne TS autotransformers and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. The area has been divided into two sub-regions as shown in Figure 4-1 and described below:

The Ottawa Area Sub-region comprises primarily the City of Ottawa. It is supplied by two (2) 230/115 kV autotransformer stations (Hawthorne TS and Merivale TS), eight (8) 230 kV and thirty-three (33) 115 kV transformer stations stepping down to lower voltages. Local generation in the area consists of the 74 MW

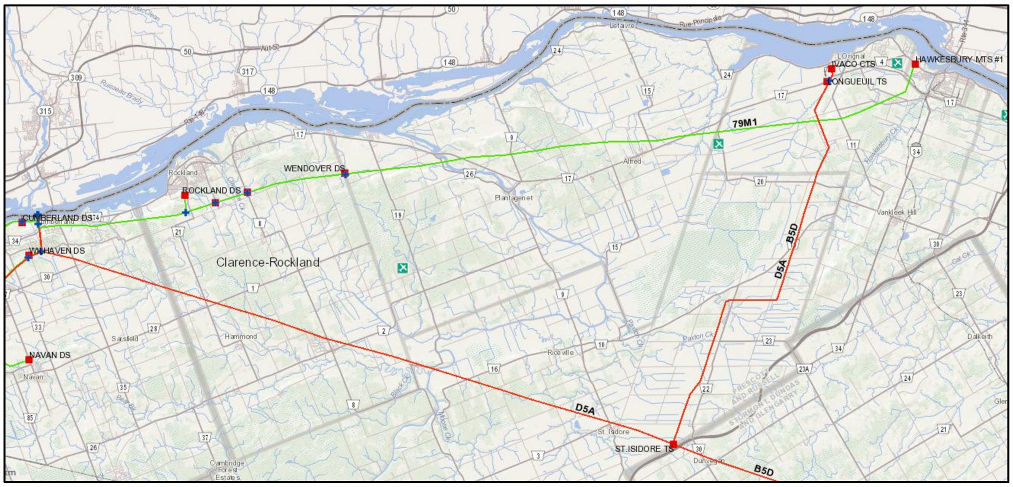
Non-Utility Generator ("NUG") CGS-2 located near the downtown area and connected to the 115 kV network. The Ottawa Area Sub-region is shown in Figure 4-2 below. Hydro Ottawa is the main LDC that serves the electricity demand for the City of Ottawa. Hydro One Distribution supplies load in the outlying areas of the sub-region. Both Hydro Ottawa and Hydro One Distribution receive power at the step-down transformer stations and distribute it to end users, including industrial, commercial and residential customers.

Figure 4-2: City of Ottawa Sub-Region Map



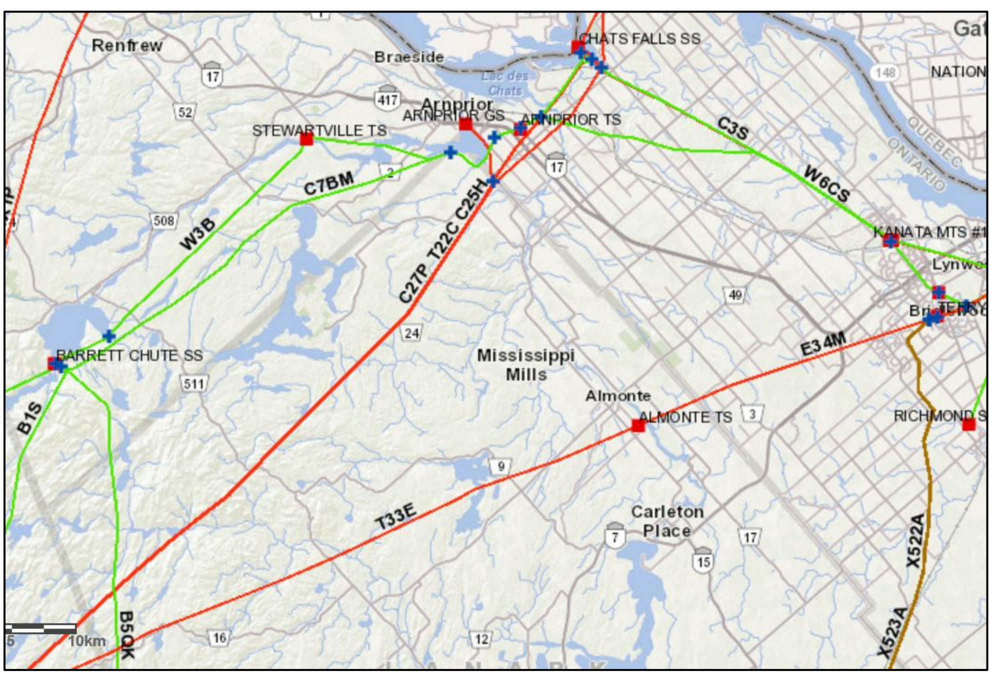
The Outer Ottawa Sub-Region covers the remaining area of the Greater Ottawa Region. The eastern area as shown in Figure 4-3 below is served by three (3) 230 and five (5) 115 kV step-down transformer stations. Hydro One Distribution and Hydro Hawkesbury are the LDCs in the area that distribute power from the stations to their end use customers. Hydro 2000 is an embedded LDC that supplies its customers from Longueuil TS via Hydro One Distribution's 44kV feeders. It also includes a large industrial customer, in L'Orignal, Ontario.

Figure 4-3: Outer Ottawa Sub-Region Map (Eastern Part)



The western area of the Outer Ottawa Sub-Region, shown in Figure 4-4 is served by one (1) 230 kV and two (2) 115 kV step-down transformer stations. Hydro One Distribution is the LDC that supplies its end use customers from these stations. Ottawa River Power Corp. is an embedded LDC that supplies its customers from Almonte TS via Hydro One Distribution's 44kV feeders. Renfrew Hydro is an embedded LDC that supplies its customers from Stewartville TS via Hydro One Distribution's 44kV feeders. The area includes the following generating stations: Barrett Chute GS, Chats Falls GS and Stewartville GS with a peak generation capacity of about 450 MW.

Figure 4-4: Outer Ottawa Sub-Region Map (Western Part)



Electricity demand in the region is projected to grow steadily over the forecast horizon, primarily driven by municipal expansion, increased commercial development, and the accelerating impacts of electrification and decarbonization initiatives. A key factor influencing long-term demand and supply requirements is the planned phase-out of natural gas heating, which is expected to significantly increase electricity consumption in the sub-region, particularly in the latter years of the forecast period. The circuits and stations of the area are summarized in Table 4-1 below:

Table 4-1: Transmission Station and Circuits in the Greater Ottawa region

115kV circuits	230kV circuits	Hydro One Transformer Stations		Generation Stations
A2	B5D	Albion TS	Marchwood MTS	CGS-1
A3RM	C3S	Almonte TS	Marionville DS	CGS-2
A4K	D5A	Arnprior TS	Merivale MTS	Chat Falls GS
A5RK	E34M	Bridlewood MTS	Moulton MTS	Stewartville GS
A6R	L24A	Bilberry Creek TS**	CTS -2	Barret Chute GS
A8M	M30A	Cambrian MTS	NRC TS	
C7BM	M31A	Carling TS	Navan DS	
F10MV	M32S	Centrepoint MTS	Nepean Epworth MTS	
H9A		Clarence DS	Nepean TS	
L2M		Cumberland DS	Orleans TS	
M1R		Cyrville MTS	Overbrook TS	
M4G		Ellwood MTS	Richmond South MTS	
M5G		Fallowfield MTS	Riverdale TS	
S7M		Greely DS	Russell DS	
V12M		Hawthorne TS*	Russell TS	
W6CS		Hawkesbury MTS #1	Rockland DS	
79M1		Merivale TS*	Rockland East DS	
		Hinchey TS	Slater TS	
		CTS-1	South Gloucester DS	

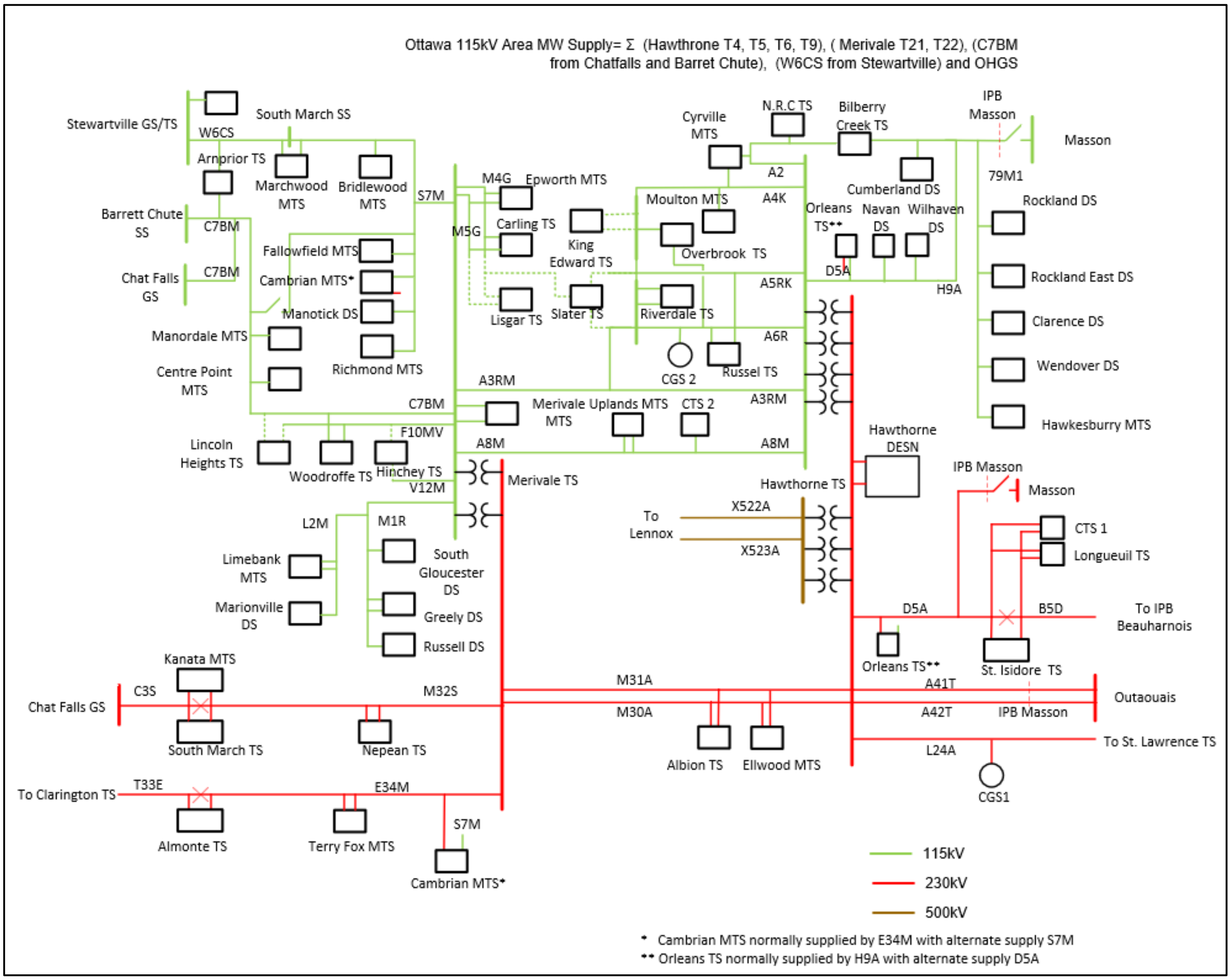
		Kanata MTS King Edward TS Limebank MTS Lincoln Heights TS Lisgar TS Longueuil TS Manotick DS	South March TS St. Isidore TS Stewartville TS Terry Fox MTS Uplands MTS Wendover DS Wilhaven DS Woodroffe TS	

*****Stations with Autotransformers installed

** Planned to decommission

The single line diagram of the existing Transmission Network of Greater Ottawa region is shown in Figure 4-5 below.

Figure 4-5: Greater Ottawa Transmission Single Line Diagram



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

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

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

I. Following Major projects were completed during the last ten years:

1. Build New Orleans TS (2015) – built a new step-down transformer station in East Ottawa supplied from 230 kV circuit D5A and 115 kV circuit H9A. This station provides additional load meeting capability to meet Hydro One Distribution and Hydro Ottawa requirements. It provides improved reliability for Hydro One Distribution customers in the Orleans-Cumberland area.
2. Hinchey TS (2015) – Connected idle winding of transformers T1/T2 to new Hydro Ottawa metalclad switchgear to provide additional load meeting capability at the station.
3. Add 230 kV inline breaker on 230 kV circuit M29C at Almonte TS (2015) – added breaker to improve reliability of supply for Almonte TS and Terry Fox MTS and split line M29C into E34M and E29C (now T33E)
4. Overbrook TS (2017): Replaced 45/60/75 MVA, 115/13.8 kV step down transformers with new 60/80/100 MVA, 115/13.8 kV based on asset condition assessment replaced transformers with higher capacity units to provide additional load meeting capability at the station due to anticipated load growth.
5. Hawthorne TS (2019): Replaced 50/67/83 MVA, 230/44 kV step down transformers with new 75/100/125 MVA, 230/44 kV units based on asset condition assessment replaced transformers with higher capacity units to provide additional load meeting capability at the station due to anticipated load growth.
6. Change supply to Overbrook TS (2019) – Reduced the loading on A4K by modifying the supply to Overbrook TS by connecting transformer T1 to A6R instead of A4K. This was accomplished by rebuilding the line section of A5RK from Riverdale JCT to Overbrook TS as a double circuit 115 kV line and tapping A6R at Riverdale JCT.
7. Connection of CGS 1 wind farm (2020) – connection of 100 MW wind farm to 230 kV circuit L24A.

8. Hawthorne TS T5 and T6 autotransformer replacement (2021): Replace 225 MVA, 230/115 kV autotransformers T5 and T6 with new 250 MVA, 230/115 kV autotransformers to provide additional 230/115 kV transformation capacity.
9. King Edward TS transformer T3 replacement (2021): Replacement of 45/60/75 MVA, 115/13.8 kV step down transformer T3 with upgraded 60/80/100 MVA, 115/13.8 kV to match the existing rating of T4 and to provide additional load meeting capability at the station.
10. Connection of Cambrian MTS (2022): connect a new Hydro Ottawa owned transformer station in the South Nepean area. The station is supplied from 230kV circuit E34M with alternate supply from 115kV circuit S7M. S7M was rebuilt as a double circuit line from the main line (S7M STR673JCT to Cambrian JCT (~10.9km) with a 1.3km extension to Cambrian MTS.
11. Overbrook TS LV cable review (2022): the transformer cable capacity limitation review was analyzed. The transformer LTR was increased based on the result of the study.
12. Arnprior TS T1/T2 replacement (2023): The two 25/33/42 MVA 115.5kV/44kV transformers were replaced like-for-like with new standard 25/33/42 MVA 110kV/44kV transformers.
13. M30A/M31A upgrade (2023): Increase the power interface limit between Hawthorne TS and Merivale TS by replacing the existing conductor 1843.2kcmil with new twin bundled 1443.7 kcmil conductor (2 conductors per phase).
14. Slater TS T2/T3 replacement (2024): Replaced 38/63 MVA, 110/12 kV step down transformers T2 and T3 with new 60/80/100 MVA, 110/14.2 kV units based on asset condition assessment replaced transformers with higher capacity units to provide additional load meeting capability at the station.
15. Lincoln Heights TS T1/T2 (2024): Like-for-like replacement of the two 45/60/75 MVA 110kV/14.2kV transformers.
16. Longueuil TS T1/T2 replacement (2025): Replacement of 50/75/93 MVA 235kV/44kV transformers T1/T2 with standard 50/67/83 MVA 215.5kV/44kV units.
17. Lisgar TS T1 replacement (2025): Replacement of 45/60/75 MVA 110/14.2-14.2 kV transformer T1 with standard 60/80/100 MVA 110/14.2-14.2kV unit.

II. Following Major projects are underway:

1. Piperville MTS – Connection of Hydro Ottawa’s new transformer station to 230 kV L24A circuit with in-service date in Q2 2026.
2. Russell TS – T1/T2 transformers (45/60/75 MVA) will be replaced with 60/80/100 MVA transformers. The planned in-service date is 2027.
3. Connection of Hydro Rd. MTS – Connection of new Hydro Ottawa station to 230kV circuits M30A/M31A near Hawthorne TS. Building ~500m line tap to the new station. The planned in-service date for connection of this new station is October 2027.
4. Connection of Mer Bleue MTS - Connection of new Hydro Ottawa station to 230kV circuits D5A about 10km east of Hawthorne TS. The planned in-service date for connection of this

new station is July 2027. This project is also planned to connect to circuit A25 with expected in-service in June 2029. Please refer to section 8.4.5 for further information.

5. Connection of South March BESS – Connection of new 250MW Battery Energy Storage System to 230kV circuit C3S about 11.5km from South March TS. The planned in-service date for connection is Q2 2027.
6. Connection of Trail Road BESS - Connection of new 159MW Battery Energy Storage System to 230kV circuit E34M about 275m from Cambrian JCT. The planned in-service date for connection is 2027.
7. Hawkesbury MTS: Project for transformer upgrade with a new 15MVA transformer unit is underway and is being led by Hydro Hawkesbury. The planned in-service date is 2027-2028.
8. Merivale TS T22/T23 – The planned in-service date for replacement of autotransformer T22 and addition of new autotransformer T23 and for replacement of six (6) 230 kV circuit breakers and four (4) 115 kV circuit breakers is 2029.
9. Bilberry Creek TS – The station is expected to be retired around 2030. Its load will be transferred to Mer Bleue MTS and Orleans TS. Please refer to section 8.4.5 for further information.
10. Orleans TS – The station will be upgraded from dual supply of 230/27.6 kV 115/27.6 kV to 230/27.6 kV DESN. The planned in-service date is June 2029. Please refer to section 8.4.5 for further information.

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

6. LOAD FORECAST AND STUDY ASSUMPTIONS

6.1. Load Forecast

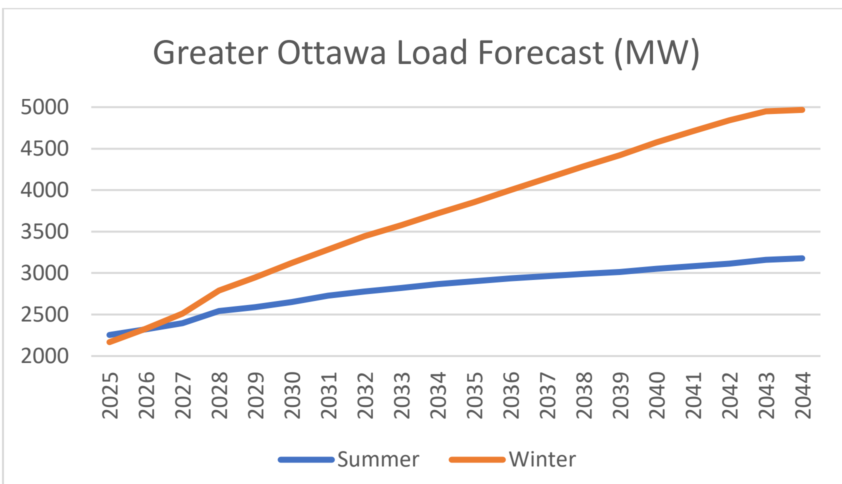
The TWG developed a load forecast for stations in the Outer Ottawa area as these were outside the IRRP scope. The LDCs also reviewed the IRRP forecast and provided revisions for some of the stations. For the remaining stations, the IRRP load forecast was adopted for the RIP study, as no changes were required by the LDCs. TWG participants, including representatives from LDCs, IESO and Hydro One provided information and input for the IRRP and RIP Load forecasts. During the IRRP stakeholder engagement process, IESO received municipal input on future load growth for consideration in the IRRP load forecast.

During the study period, the load in the Greater Ottawa region is expected to grow at an average annual rate of approximately 2% in summer and 4% in winter from 2025 to 2044. The region is currently summer-peaking, however based on the forecast it is expected that the region will transition to winter-peaking in the near future. This shift is largely driven by electrification such as the ongoing transition of heating systems from natural gas to electric or hybrid solutions, which will significantly increase electricity demand during winter months.

Figure 6-1 shows the Greater Ottawa region extreme summer/winter weather net load MW forecast from 2025 to 2044. The load forecasts from the Ottawa sub-region were updated from the IRRP forecast as agreed by the TWG.

The forecast for the individual stations in the region is available in Appendix A and is used to determine any need in the region.

Figure 6-1: Greater Ottawa region summer/winter Net Peak Load Forecast



6.2. Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2025-2044.
- LDCs have reviewed the forecast and provided updates where necessary and reconfirmed load forecasts up to 2044 in the area.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is currently summer peaking but expected to become winter peaking within the study period, so this assessment considers both summer and winter peak loads.
- Station capacity adequacy is assessed by comparing the station peak load with the station’s normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR) based on 35°C ambient temperature.
- Adequacy assessment is conducted as per ORTAC.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the Greater Ottawa region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway, listed in **"Section 5"** are completed as per their respective in-service dates.

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

- Greater Ottawa region Third cycle Needs Assessment Report, Completed in December 2022 by Hydro One
- Greater Ottawa region Third cycle Scoping Assessment Report, Completed in March 2023 by the IESO
- Greater Ottawa region Third cycle Integrated Regional Resource Plan Report, Completed in July 2025 by the IESO

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

7.1. Asset Renewal Needs for Major HV Transmission Equipment

In addition to the asset renewal needs identified in the previous regional planning cycle, Hydro One and TWG have also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Greater Ottawa region. The complete list of major HV transmission equipment requiring replacement in the Greater Ottawa region is provided in Table 7-1 in this sub-section. Hydro One along with Hydro Ottawa Ltd and Hydro Hawkesbury are the only Transmission Asset Owner (TAO) in the Region

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

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

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

- 230/115kV autotransformers
- 230 and 115kV load serving step down transformers
- 230 and 115kV breakers where:
    - replacement of six breakers or more than 50% of station breakers, the lesser of the two

- 230 and 115kV transmission lines requiring refurbishment where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230 and 115kV underground cable requiring replacement where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

Table 7-1: Major HV Transmission Asset assessed for Replacement in the region planned in next 10 years

Station/Circuit	Need Description	Planned ISD
South March TS	T1/T2 Transformers replacement	2031
Albion TS	T1/T2 Transformers replacement	2031
Nepean TS	T3/T4 Transformers replacement	2034
S7M	Refurbishment of line section between Manotick JCT x Richmond South MTS and S7M 673N x Manordale JCT	2030

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

7.2. Station Capacity Needs

Over the study period **2025 -2044** RIP reviewed the capacity of all the 230kV and 115kV Transforming stations within the **Greater Ottawa region**. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 7-2 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer and winter) Limited Time ratings.

Table 7-2: Greater Ottawa region Station Capacity Needs in the study period

Sr.no.	Station Name	Station LTR (MW) (Summer/Winter)	2024 Loading (MW) (Summer/Winter)	Need Date (Summer/Winter)	High Forecast Need Date (Summer/Winter)
1	Albion TS	86.5/101.7	57.4/47.0	-/2034	2043/2030
2	Arnprior TS	54.9/59.4	36.9/37.5	2044/-	2043/-
3	Bridlewood MTS	23.5/23.5	29.6/19.7	2035/2030	2029/2027
4	Cambrian MTS	114/123.5	58.7/33.6	-/2041	-/2033
5	Carling TS	95/124.3	67.7/64.9	2028/2028	2028/2028
6	Centrepoint MTS	13.3/13.3	14.6/11.9	2032/2027	2027/2025

7	Cumberland DS	6.8/8.6	5.5/5.0	2037/-	2036/-
8	Cyrville MTS	47.5/47.5	33.6/24.4	2028/2030	2028/2028
9	Ellwood MTS	47.0/47.0	44.8/46.5	2027/2027	2027/2025
10	Fallowfield MTS	27.2/27.2	35.6/14.4	2026/2030	2026/2028
11	Greely DS	20.7/25.2	19.5/16.3	2025/2025	2025/2025
12	Hawkesbury MTS	18/18	13.3/14.9	-/2037	-/2036
13	Hawthorne TS	144.8/	106.1/97.1	2038/2031	2038/2028
14	Hinchey TS	85.6/95.0	45.4/40.8	-/2031	-/2029
15	Kanata MTS	51.5/51.5	53.2/55.8	2025/2025	2025/2025
16	King Edward TS	86.9/90.3	80.0/77.7	2033/2026	2030/2025
17	Limebank MTS	75.0/75.0	48.1/38.2	2031/2028	2031/2026
18	Lincoln Heights TS	99.4/113.1	40.3/40.9	-/2039	-/2035
19	Lisgar TS	83.4/105.1	42.7/58.9	2028/2028	2028/2027
20	Manordale MTS	9.6/9.6	11.0/8.4	2026/2026	2025/2025
21	Manotick DS	7.7/10.4	9.5/8.1	2025/2025	2025/2025
22	Marchwood MTS	32.3/32.3	46.3/42.5	2025/2025	2025/2025
23	Marionville DS	13.5/13.5	14.4/12.1	2025/2025	2025/2025
24	Moulton MTS	32/32.0	21.6/16.6	2028/2028	2028/2028
25	Nepean Epworth MTS	12.9/12.9	11.4/11.4	2035/2028	2029/2026
26	Nepean TS	144.1/160.7	113.2/108.6	-/2030	-/2027
28	Richmond South MTS	49.0/49.0	19.4/6.9	2034/2028	2034/2028
29	Riverdale TS	110.8/117.0	92.4/71.5	2030/2028	2029/2026
30	Rockland DS	7.8/10.5	7.8/4.1	2025/2031	2025/2030
31	Rockland East DS	15.5/20.9	14.3/12.4	2026/2040	2026/2040
32	South March TS	99.2/113.7	95.9/72.2	2026/2028	2026/2027
33	Terry Fox MTS	91.7/105.8	53.9/41.7	-/2038	-/2032
34	Woodroffe TS	97.4/102.4	33.4/28.9	-/2039	-/2034

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

7.3. Transmission Line Capacity Needs

Over the study period **2025-2044** RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the **Greater Ottawa region**. The NA and IRRP studies had previously indicated that the following Transmission lines require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast and following contingencies, the Transmission lines which require capacity relief during the study period are shown in Table 7-3 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 7-3: Greater Ottawa region Transmission Line Capacity Needs in the study period

Sr.no.	Name of Circuit	Name of Section	Maximum capacity	Current loading	Need Date
1	M4G/M5G	Merivale TS x Carling TS	1279 A	503 A	2030
2	L2M	Merivale TS X Limebank JCT	467 A	339 A	2028
3	S7M	Merivale TS x STR654JCT (Fallowfield tap)	1381 A	488 A	2032
4	C7BM	Merivale TS x NQL1 JCT	777 A	455 A	2034 (winter)
5	F10MV	City View JCT x Woodroffe TS	777 A	402 A	2034 (winter)
6	A4K	Hawthorne TS x Cyrville JCT x Overbrook TS	1214 A	550 A	2032/33 (winter)
7	A4K	Overbrook TS x King Edward TS	800 A	204 A	2032/33 (winter)
8	A3RM	Ellwood JCT x Riverdale JCT	1016 A	235 A	2034
9	A5RK	Hawthorne TS x Russel TS	1595 A	538 A	2034
10	A6R	Hawthorne TS x Russel TS	1703 A	489 A	2034

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

7.4. System Reliability, Operation and Load Restoration Needs

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

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

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

The following load security needs were reviewed as a part of RIP:

M32S

Nepean TS is supplied solely by the 230 kV M32S circuit, and a contingency on M32S would result in the complete loss of load at Nepean TS due to its configuration. Under current load security criteria, no more than 150 MW should be lost for a single element contingency. While this limit is not exceeded in the summer forecast, it is projected to be reached in the winter forecast by 2029. A working group recommendation is discussed in section 8.4.

M1R+L2M

Circuits M1R and L2M share a breaker position at Merivale TS, so the loss of either circuit results in both being tripped. This configuration affects stations including Limebank MTS, Marionville DS, South Gloucester DS, Greely DS, and Russell DS. For this group, the 150 MW load security threshold is expected to be reached in the summer forecast by 2040 and in the winter forecast by 2031. A working group recommendation is discussed in section 8.4.

Load Restoration for C3S/M32S

M32S is a 230kV circuit connecting Merivale TS to South March TS, and 230kV circuit C3S connecting Chats Falls SS to South March TS. The two circuits are connected through an in-line breaker A1A2 at South March TS. Stations South March TS and Kanata MTS are supplied by both C3S and M32S. Nepean TS is only fed from circuit M32S. Load restoration was assessed for A1A2 breaker fail. The breaker fail condition can lead to no supply to all three stations. The loss of the two circuits results in approximately 330MW of load loss during summer. As per ORTAC, 80MW have to be restored in 30 minutes, 150MW restored in 4 hours and the entire load in 8 hours. Nepean TS can be restored by opening circuit switcher M32S-1 within 30 minutes. The breaker A1A2 disconnect switches at South March TS can be opened within 30 minutes to restore load stations from either C3S or M32S. All load can be restored within 4 hours. In addition, as discussed in section 8.4 a new switching station is planned at South March TS, which will eliminate this problem.

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

Load Restoration for S7M

Circuit S7M and W6CS are tie via an in-line breaker L6L7 at South March SS. A L6L7 breaker failure results in no supply to Fallowfield MTS, Richmond MTS, Manotick DS, Bridlewood MTS, and Marchwood MTS. The amount of load loss is about 199 MW by the end of the study period in summer. As per ORTAC, all load above 150MW must be restored in 4 hours and all load restored in 8 hours. All load can be restored by opening breaker L6L7 disconnect switches at South March SS within 4 hours. The Study Team recommends that no further action is required at this time.

During winter time under contingency of S7M 150 MW can be interrupted by configuration by 2036. TWG recommends monitoring the winter load and addressing the need in the next regional planning cycle.

Load Restoration for D5A/B5D

Circuits D5A and B5D supply Longueuil TS, St Isidore TS, and Ivaco CTS. The worst contingency for the area can result in approximately 212MW of load loss. Hydro One prepared a Local Planning report which considered the loss of up to 174MW of load for the same contingency. Hydro One has reviewed the report and determined that the conclusions of the report are still applicable to the new load forecast. The report shows that all load can be restored in at least 4 hours, meeting ORTAC restoration criteria. The Study Team recommends that no further action is required at this time.

Load Restoration for M4G/M5G

Load restoration was assessed for the 115 kV double-circuit M4G/M5G supply serving Nepean–Epworth MTS, Carling TS, and Lisgar TS in downtown Ottawa. Although Slater TS is also supplied from M4G, it was excluded from this assessment because it has alternate supply from two other circuits and therefore does not drive the same restoration need. Based on the load forecast, the combined demand on M4G/M5G is expected to exceed 250 MW in the mid-term; under ORTAC, loads greater than 250 MW must be restored within 30 minutes following a contingency. To ensure compliance with this requirement as loading increases, Hydro Ottawa and Hydro One will review restoration options, which may include LV load transfers and/or additional switching and operational restoration actions. The TWG recommends that this review be reviewed as part of the M4G/M5G upgrade and/or the Bronson connection project scopes, where practical restoration enhancements can be implemented and validated against the 30-minute restoration criterion.

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the Greater Ottawa region. These needs include those previously identified in the NA and IRRP for the Greater Ottawa region as well as any new needs identified during the RIP phase. All estimated costs included in the alternative analysis are considered as planning budgetary estimates and are used for comparative purposes only and may vary. The Needs in the region are summarized below in Table 8-1 below:

Table 8-1: Near/Mid-term Needs Identified in the region

Station/Circuit Name	Description of Need	Need Date	RIP Report Section
Asset Renewal Needs			
South March TS	Replacement of T1/T2 transformers with upgraded units based on asset conditions and capacity needs.	2031	8.1.1
Albion TS	Replacement of T1/T2 transformers with upgraded units based on asset condition and capacity needs.	2031	8.1.2
Nepean TS	Replacement of T3/T4 transformers based on asset condition	2034	8.1.3
S7M	Refurbishment of line section between Manotick JCT x Richmond South MTS and S7M 673N x Manordale JCT	2030	8.1.4
Station Capacity Needs			
Kanata North MTS	Build a new Transformer Station by connecting 230 kV C3S and a new transmission line from Merivale TS.	2028	8.2.1
Bronson MTS	Build a new 115kV Transformer Station east of Carling TS by converting existing Bronson distribution station	2031	8.2.2
Greenbank MTS	Build new Transformer Station to meet demand growth and need for 28kV supply west of Merivale TS.	2028	8.2.3

South March TS	Replacement of T1/T2 transformers and associated equipment's with upgraded units based on capacity needs.	2026	8.2.4
Albion TS	Replacement of T1/T2 transformers and associated equipment's with upgraded units based on capacity needs.	2031	8.2.5
Carling TS	Station capacity will be exceeded due to limiting components at LV side. Replacing limiting LV cables will add capacity to station.	2028	8.2.6
Lisgar TS	Station capacity will be exceeded due to limiting LV cables and 75 MVA transformer unit (T2).	2028	8.2.7
King Edward TS	Station capacity will be exceeded due to limiting components at LV side. Replacing LV components will add capacity to station.	2026	8.2.8
Nepean TS	Station capacity will be exceeded during winter season.	2030	8.2.9
Riverdale TS	Station capacity will be exceeded due to limiting LV components and 75 MVA transformer units.	2028	8.2.10
Cyrville MTS	Station voltage conversion from 115kV to 230kV to increase station rating.	2028	8.2.11
Moulton MTS	Relocate 50 MVA ,115kV transformers from Cyrville MTS after voltage conversion to increase station rating at Moulton TS.	2028	8.2.12
Marionville DS	Install a second transformer to increase station rating.	2025	8.2.13
Greely DS	Install SCADA transformer fan monitoring	2025	8.2.14
Manotick DS	Load transfer from T1 to T2 at Manotick DS	2025	8.2.15
Hinchey TS	Load to be monitored and necessary actions to be taken as load picks up.	2031	8.2.16
Rockland DS	Install SCADA transformer fan monitoring	2025	8.2.17
Rockland East DS	Install SCADA transformer fan monitoring	2026	8.2.18
Manordale MTS	Load transfers to existing stations	2026	8.2.19

Nepean Epworth MTS	Load transfers to existing stations	2028	8.2.19
Kanata MTS	Load transfers to existing stations	2025	8.2.19
Ellwood MTS	Load transfers to existing stations	2027	8.2.19
Limebank MTS	Load transfers to existing stations	2028	8.2.19
Bridlewood MTS	Load transfers to existing stations	2030	8.2.19
Marchwood MTS	Load transfers to existing stations	2025	8.2.19
Centrepoint MTS	Load transfers to existing stations	2027	8.2.19
Fallowfield MTS	Load transfers to existing stations	2026	8.2.19
Transmission Line Capacity Needs			
M4G/M5G	Uprate Line section between Merivale TS x Carling TS	2030	8.3.1
L2M	Uprate line section between Merivale TS x Limebank JCT	2028	8.3.2
A4K	Continue to monitor the winter load.	2032/33	8.3.3
System Reliability, Operation and Load restoration Needs			
Load Security issue due to contingency of M32S	Provide a second supply to Nepean TS via a new transmission circuit from Merivale TS.	2029	8.4.1
Kanata Area	New Switching Station to improve reliability and flexibility in Kanata Area		8.4.2
Load Security issue due to contingency of M1R+L2M	Install a new breaker at Merivale TS and separate L2M and M1R breaker positions.	2031	8.4.3
Loading and voltage issues on S7M	Continue monitoring load growth and system performance	2032	8.4.4
East Ottawa Area	Supply in East Ottawa Area	2029-2030	8.4.5

8.1 Asset Renewal Needs for Major HV Transmission Equipment

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

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

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

8.1.1 South March TS T1/T2

The existing transformers 50/83 MVA 230/44 kV T1 and T2 at South March TS were originally commissioned in 1971 and based on asset condition assessment, they are identified for replacement in 2031.

A like-for-like replacement of these units would not be adequate in meeting the load during the study period. However, as discussed in Section 8.2, there are station capacity needs in the near term which require upsizing the transformers.

As outlined in the Ottawa area sub-region IRRP and endorsed by the TWG, the recommended solution is to replace the existing transformers with new 75/125 MVA units. This upgrade will ensure adequate capacity and reliability for the growing load in the South March area. Hydro One is working to accelerate the replacement schedule to 2029–2030 to address reliability risks and align with regional planning objectives.

8.1.2 Albion TS T1/T2

Albion TS has two power transformers rated at 45/60/75 MVA, 230 kV / 14 kV / 14 kV, built in 1970. Based on asset condition assessment, these transformers are identified for replacement in 2031.

The 13.8 kV metalclad switchgear installed since 1971 contains six air circuit breakers and two SF6 capacitor bank breakers. The station also has four 13.8 kV conventional SF6 breakers. All circuit breakers require replacement in the near to medium term planning horizon.

The existing transformers at Albion TS will be replaced with new standard 60/80/100 MVA units. These are closest standard size units to the existing transformers. All existing Hydro One owned circuit breakers will be replaced with breakers of similar rating. This alternative would address the asset renewal needs and would maintain reliable supply to customers.

However, as discussed in Section 8.2, additional station capacity will be required in the mid-term, necessitating upgrades at Albion TS.

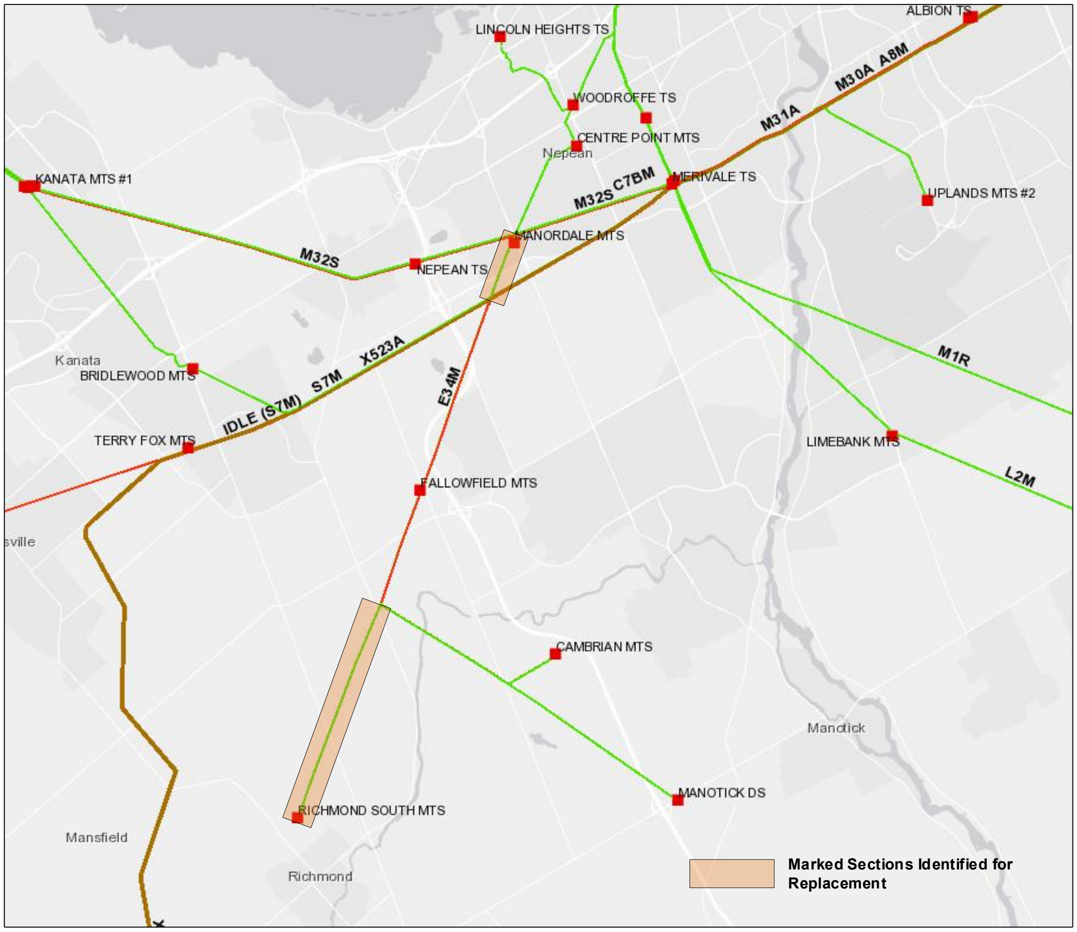
8.1.3 Nepean TS T3/T4

Nepean TS has two power transformers rated at 75/125 MVA, 230 kV / 14 kV / 14 kV, built in 1970's. Based on asset condition assessment, these transformers are identified for replacement in with like-for-like units as this is the highest rating available, with a planned in-service date of 2034.

8.1.4 S7M Line Refurbishment

Two sections of circuit S7M between Manotick JCT × Richmond MTS (5 km) and S7M STR 673N JCT × Manordale JCT (1.4 km) are identified for replacement as shown in Figure 8-1. These sections are 115 kV predominantly wood pole transmission line that was originally placed in service in 1928. Asset renewal is required on these line sections.

Figure 8- 1: S7M section requiring sustainment highlighted



Two possible options are considered for this line section rebuild:

Alternative 1 - Rebuild H frame wood structures: This alternative would be a like for like rebuild of the existing 5km of 115kV transmission line. This would be adequate to supply the forecasted load at Richmond South MTS. The planned in-service date for this refurbishment is 2030.

Alternative 2 - Upgrade to 230 kV ready operation by rebuilding the 115kV single circuit line as a double circuit 230kV line. This would be similar to upgrade done to S7M for the Cambrian MTS Connection as described in Section 5. This alternative considers possible area conversion to 230kV by making the rebuild ready for the upgrade. This would be in accordance with the long-term plan for the area as described in IRRP.

Recommendation:

The recommended near-term plan is to refurbish these line sections to maintain reliability. However, this line section may also be considered for a configuration change refer to Section 8.4.3. Further discussion will occur as part of bulk system planning.

8.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period **2025-2044** for the 230kV and 115kV Transformer stations in the **Greater Ottawa region** using both the summer and winter peak load forecasts that were provided by the study team. This section describes the following capacity needs that have been identified during the study period

To address the station capacity needs, the recommendation of this planning cycle is a combination of new transformer stations and upgrades at existing stations. The new stations are described first, followed by the upgrades considered at the existing stations. The RIP focuses on wire alternatives, however where possible non-wire alternatives are also considered as per the IRRP.

As can be seen in Section 6 Figure 6-1, the area winter load is expected to increase significantly over the study period. The greater Ottawa region has historically been a summer peaking region; however, the region is forecasted to become winter peaking in the near term due to the impact of measures such as electrification and decarbonization. The winter load forecast shows many stations reaching their capacity in the near midterm. Plans have been identified to address these needs and are discussed in this section.

The working group will monitor closely the winter load to track its growth and determine if the forecasted trends materialize in the short term. Many stations are forecasted to go over their transformation capacity and in the long term are expected to far exceed the station LTR. Significant investments will be required at the bulk and regional level to meet this load. Thus, the TWG will monitor the demand in the coming winters and may decide to trigger the next regional planning cycle earlier to address these emerging needs.

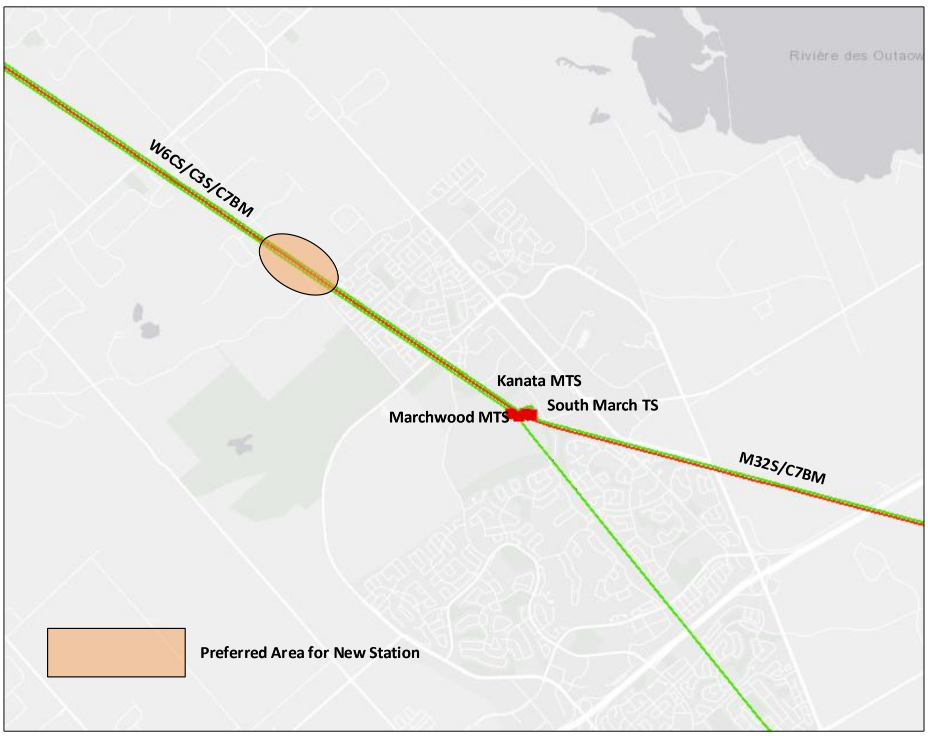
Also, please note there are several downtown stations that are recommended for upgrades in similar timeframes. The ISD highlighted in this section is based on preliminary information. Hydro Ottawa and

Hydro One will work together to review the work required and timing for each upgrade to better coordinate the plans. The dates are subject to change based on the review and determination of the preferred path to achieve all the upgrades listed.

8.2.1 Kanata North – Stittsville Area

Significant growth and capacity needs have been identified in Kanata North and Stittsville area. The area is supplied mainly through three transformer stations: Marchwood MTS, Kanata MTS, and South March TS. Based on the load forecast, all 3 stations will reach their LTR in the short term. Hydro One is proceeding with capacity upgrade at South March TS as described in section 8.2.4. However, additional transformation capacity is required and TWG, as part of the IRRP, has recommended building a new station to address this need. Hydro Ottawa has identified preferred location for the station as shown in Figure 8-2 below.

Figure 8-2: Preferred Location of New Station in Kanata North – Stittsville Area



The following alternatives were considered to meet the growth of the area.

<u>Alternative 1: New station supplied from existing single circuit 230kV line.</u>

Build a new station and connect to 230kV circuit C3S as shown in Figure 8-3. The station would have sufficient capacity to address the growth of the area over the study period. However, a single circuit supply would not provide the same level of reliability as the stations in the area currently have. Also, depending on the dispatch of resources and system configuration of the area, the existing system capacity to meet the demand is limited.

Alternative 2: New station supplied from two 230kV circuits.

Build the station as described in Alternative 1 and bring an additional 230kV supply. Please refer to Figure 8-4 below. The new circuit would be extended from M32S at South March TS and would help meet load growth over a wider range of system conditions. The new circuit would make use of the existing right of way by rebuilding one of the 3 circuits as a double circuit line.

Preliminary review of possible transfers to the new station has been considered and a revised forecast for the stations in the area is shown in Table 8-2.

Table 8-2. Updated summer forecast (MW) with transfers to Kanata North Considered.

	LTR (MW)	2027	2028	2029	2030	2031	2032	2033	2034	2035
Marchwood MTS	32.2	52.9	33.1	34.3	35.3	36.4	37.4	38.7	39.4	39.2
Kanata MTS	51.5	53.8	36.8	36.4	36.2	36.0	35.7	35.6	35.6	35.4
Kanata North MTS	108[1]	0	38	38.4	38.7	39.1	39.4	39.8	40	40.4

[1]Capacity for the new station will be confirmed as the project progresses.

Figure 8-3: Connection of New Kanata North MTS to C3S (initial connection)

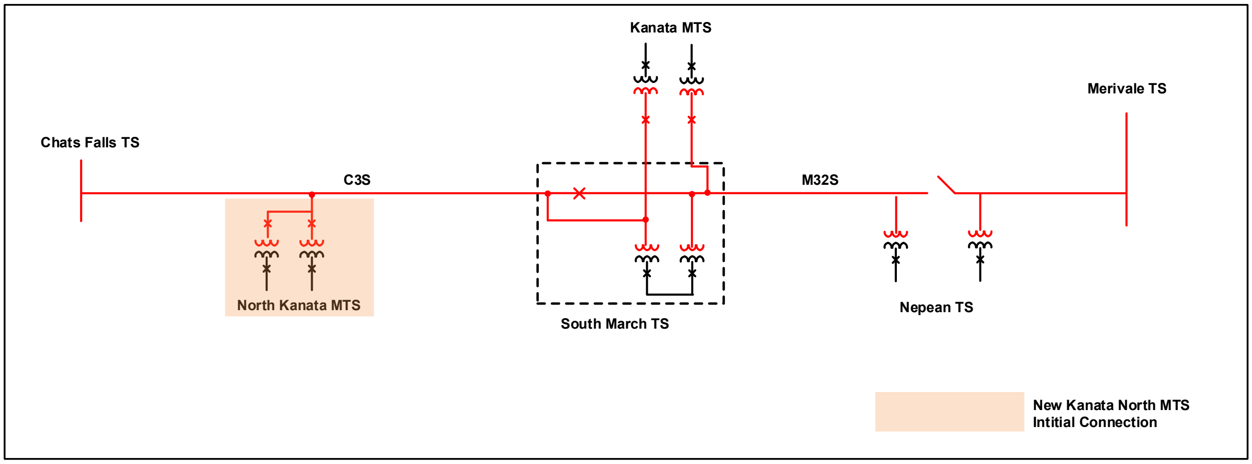
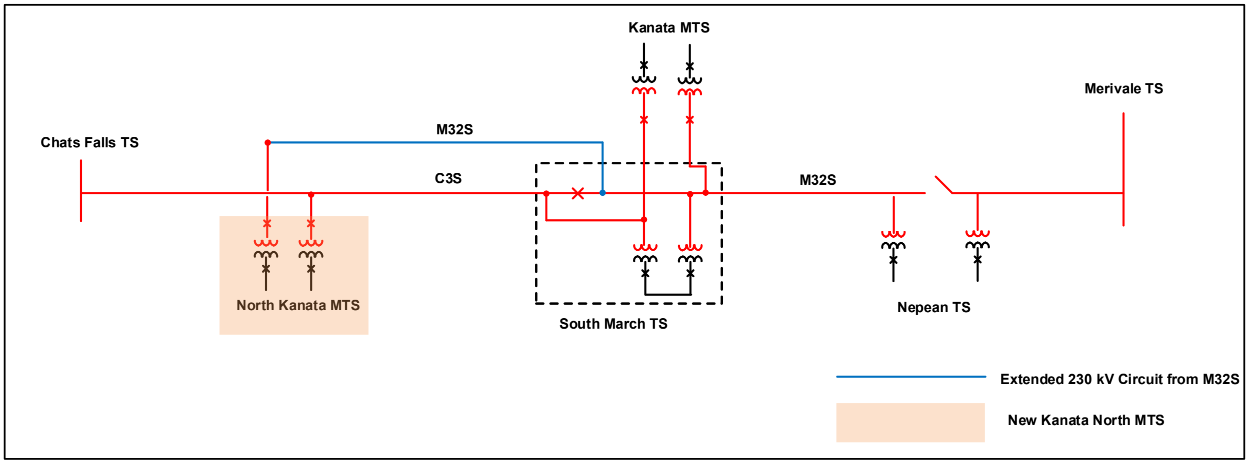


Figure 8-4: Connection of New Kanata North MTS to C3S and New Circuit (recommended alternative)

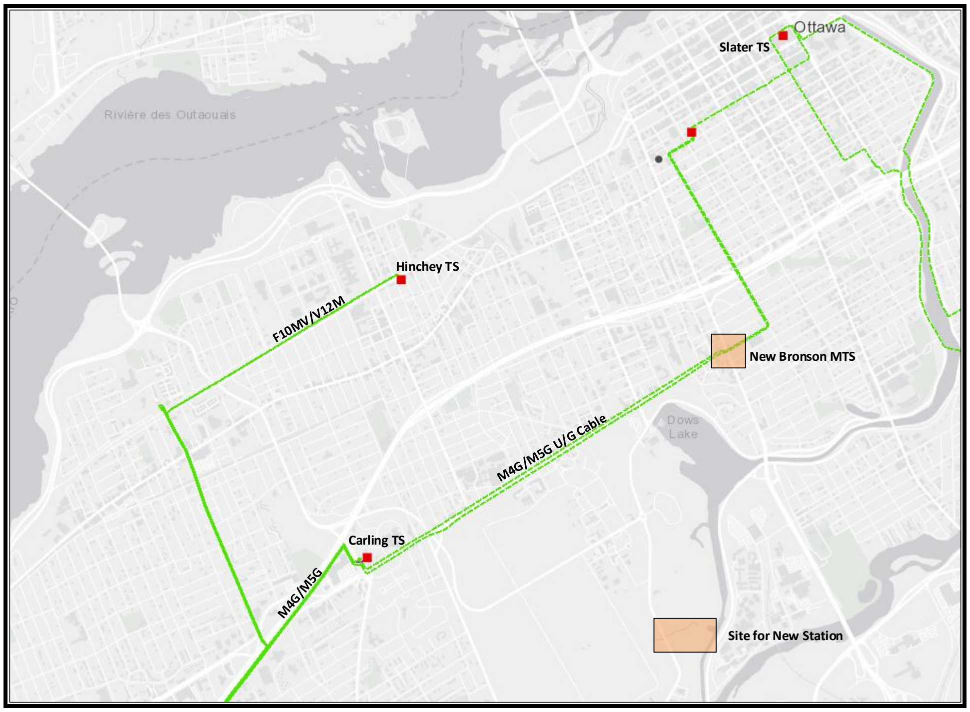


The TWG recommends Hydro Ottawa and Hydro One proceed with Alternative 2. This option will provide the necessary transformation capacity for the area and will provide higher level of reliability by having two circuits supplying the station. Based on the immediate need for transformation capacity, Hydro Ottawa is planning to build the station by 2028. In order to meet this in-service date, the station will be connected initially to existing 230kV circuit C3S only as described in Alternative 1. The second circuit is expected to be completed by 2031.

8.2.2 Bronson MTS

Several stations supplied from the 115kV network in the downtown core have been identified as reaching their capacity in the short term. Upgrading some of these stations is feasible to increase their transformation capacity. However, given the magnitude of the growth expected, additional transformation capacity in the form of a new station is required. Hydro Ottawa has identified a site for a new station: the alternative considered is to convert an existing Hydro Ottawa owned distribution station into a 115 kV DESN. The site of this station is adjacent to an underground cable section of M4G/M5G between Carling TS and Lisgar TS as shown in Figure 8-5.

Figure 8-5: Ottawa Downtown Area Map with new Bronson MTS



This conversion to a 115 kV DESN would increase the transformation capacity of the station. It would also enable load transfers from nearby stations and allow for new developments in Ottawa's Core East area, which is experiencing significant growth driven by urban densification, electrification of heating and transportation, and federal decarbonization initiatives. To note, this option would necessitate uprating circuits M4G and M5G to address thermal limitations, as discussed in Section 8.3 of this report.

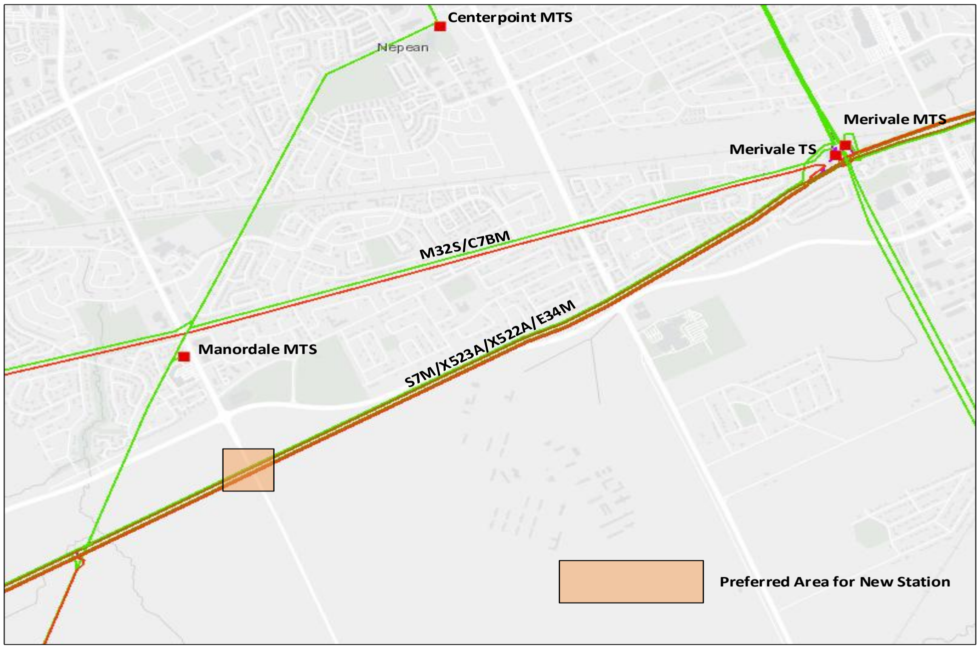
This plan was initially proposed as part of the IRRP. TWG has reviewed the need and proposed solution and reaffirmed the plan as the preferred alternative.

Hydro Ottawa and Hydro One are proceeding into studies to determine how the station will be connected to the existing 115kV underground cables. The proposed in-service date for the station is 2031.

8.2.3 Greenbank MTS

Another area expected to experience high growth is in the west of the city. The existing stations have limited capacity and TWG is recommending a new station to be built to address this need. Hydro Ottawa has identified preferred location for the station as shown in Figure 8-6 below.

Figure 8-6: Preferred Location of New Station in West Ottawa

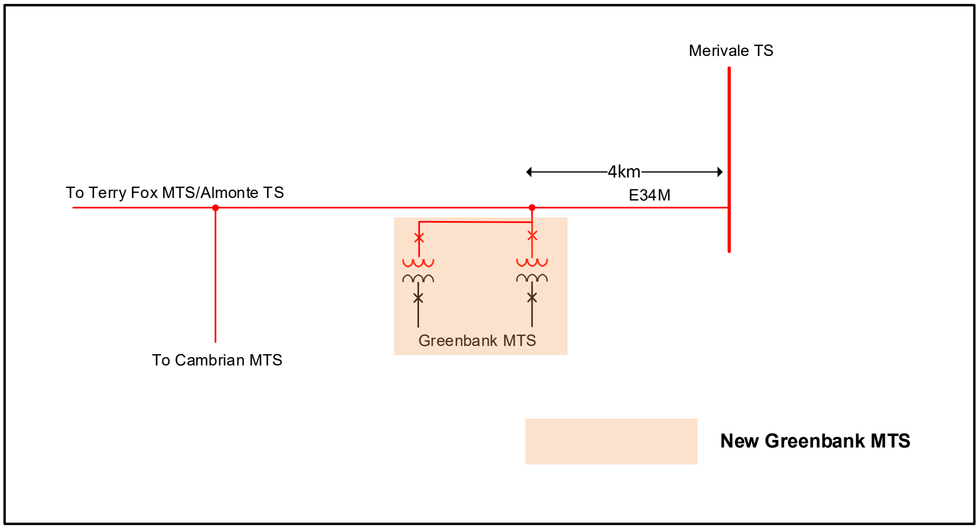


The following alternatives were considered to meet the growth of the area.

Alternative 1: New station supplied from existing single circuit 230kV line.

Build a new station and connect to 230kV circuit E34M as shown in Figure 8-7. The station would have sufficient capacity to address the growth of the area over the study period. However, connection to E34M alone would limit the growth that can be supplied from the station. In addition, the circuit needs to be connected at Merivale TS for the voltage to be acceptable.

Figure 8-7: Connection of New Greenbank MTS to E34M



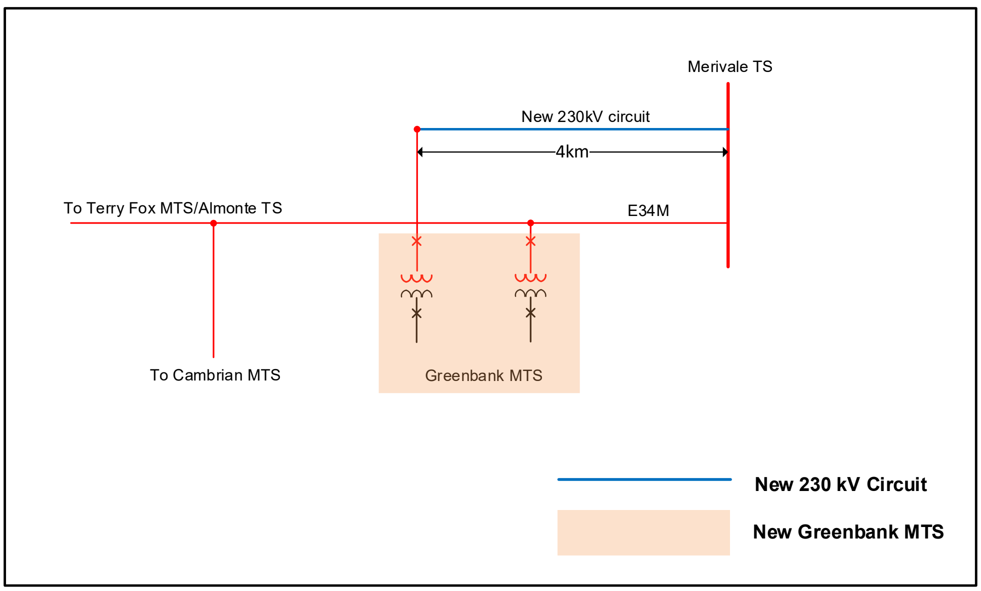
Alternative 2: New station supplied from two 230kV circuits.

Build the station as described in Alternative 1 and bring an additional 230kV supply. Please refer to Figure 8-8 below. The new circuit would be extended from Merivale along the E34M corridor. The new circuit would alleviate the concerns identified for Alternative 1 and would help meet load growth over a wider range of system conditions.

Alternative 2 was initially proposed as part of the IRRP. TWG has reviewed the need and proposed solution and reaffirms the plan as the preferred alternative.

Hydro Ottawa and Hydro One are proceeding with a project to connect the new station to the 230kV system. Hydro Ottawa's new station is planned for in-service in 2028. The new circuit must be coordinated with the Merivale TS upgrade described in Section 6 and is currently expected for in-service in 2031. Both transformers at the new station will be supplied by circuit E34M as per Alternative 1 until the new circuit is available. Operating measures may be required to help supply the load should there be issues with E34M until the second circuit is available.

Figure 8-8: Connection of New Greenbank MTS to E34M and new circuit



8.2.4 South March TS – T1/T2

South March TS, located in the Kanata–Stittsville area currently served by 230 kV circuits M32S and C3S. The station is equipped with two aging 50/83MVA 230kV/44kV transformers (T1/T2) which, based on their condition, were identified for replacement in 2030–2032 as outlined in Section 8.1.1.

Based on the updated load forecast, South March TS is projected to exceed its summer LTR by approximately 3 MW in 2026 and its winter LTR by about 6 MW in 2028, with the high-growth scenario the need date is 2026 for summer and 2027 for winter. TWG has recommended upgrading the existing transformers to new 75/125 MVA units. The tentative planned ISD for this upgrade project is scheduled in 2031- 2032. Hydro One is working to expedite the replacement work to 2029-2030 to meet the rising load growth.

In the interim, coordination with LDCs will be required to explore load transfer opportunities to adjacent stations or other operating measures to manage short-term capacity constraints until the transformer replacement is completed should there be any issues at the station.

8.2.5 Albion TS T1/T2

Albion TS is a 230 kV / 14-14 kV DESN station supplied from circuits M30A and M31A. The station's two 75 MVA, 230 kV / 14-14 kV transformers were identified for replacement based on condition assessments. Planned in-service date for this work is 2031(refer to Section 8.1.2).

Based on the load forecast, Albion TS is projected to exceed its winter LTR by approximately 3 MW in 2034, while the summer LTR remains within limits over the study period. Under the high-growth scenario, the need date is 2030 for winter and 2043 for summer.

To address the loading issue, TWG has recommended upgrading the two transformers to standard 100 MVA units, along with the metalclad switchgear upgrade. The tentative in-service date for this upgrade is 2031. A feasibility study will be conducted to determine the preferred option to upgrade the metalclad as the existing installation has space limitations which may restrict the possible upgrade.

8.2.6 Carling TS – T1/T2

Carling TS is a transformer station that steps down voltage from 115 kV to 13.2 kV that is supplied from circuits M4G and M5G. Each transformer is rated at 115/14.2/14.2 kV, 60/80/100 MVA.

Based on the forecasts, Carling TS will exceed its summer LTR by approximately 11 MW and its winter LTR by about 1 MW by 2028. The current capacity limitation is primarily due to the existing series-connected low-voltage (LV) cables which limit the station capacity.

To address this constraint, TWG recommends upgrading the LV cables associated with both transformers as the preferred solution, as it will increase station capacity and eliminate low-voltage limitations. This upgrade project is tentatively planned for an in-service date in summer 2030.

8.2.7 Lisgar TS T1/T2

Lisgar TS is an indoor facility that steps down voltage from 115 kV to 13.2 kV that is supplied from circuits M4G and M5G. Replacement of 75 MVA transformer T1 with a 100 MVA unit was recently completed in December 2025. Following this replacement, the forecasts indicate that the station will exceed its summer LTR by approximately 13 MW and its winter LTR by about 8 MW by 2028. Under the high-growth scenario, the winter need date is advanced to 2027.

The current capacity limitation is primarily due to the existing LV cables and metalclad breakers, which limit the station capacity. To address this constraint and meet future demand, TWG recommends replacing 75MVA transformer T2 with a 100 MVA unit that will match T1 and upgrading the LV cables and metalclad breakers. Based on preliminary review by Hydro One, two options are identified for the station upgrade.

Alternative 1: In-Situ replacement of transformer T2

Under this option, transformer T2 will be replaced at its existing location within Lisgar TS. During the replacement process, the entire station load will temporarily be supplied by transformer T1, which will require careful operational planning to avoid overloading. To facilitate this, Hydro Ottawa will need to implement targeted load transfers to adjacent stations to reduce stress on T1 during the outage. This approach minimizes the need for major civil works and leverages existing infrastructure. The target in-service date for this In-Situ replacement is 2031.

Alternative 2: Greenfield Replacement of transformer T2

If operational constraints or stranded load conditions make it impractical to transfer Lisgar TS load to other stations during the replacement, a greenfield approach will be considered. This involves installing the new transformer at a new location within the station property, which will require extension of the existing building and additional civil works. The target in-service date for this approach is 2034.

A conceptual layout for this greenfield approach is shown in Figure 8-9.

Figure 8-9: Lisgar TS extension under alternative 2

Recommendation:

A feasibility study will be conducted to evaluate both alternatives in detail, considering technical, and operational implications. Hydro Ottawa and Hydro One will review the options following the feasibility study and decide on the preferred alternative. In the interim, coordination with LDCs will be required to explore load transfer opportunities to adjacent stations to manage short-term capacity constraints until the transformer and component replacements are completed should there be any issues at the station.

8.2.8 King Edward TS

King Edward TS, located in the downtown core of Ottawa, supplies Hydro Ottawa customers. The station is fed by two underground 115 kV cables from A4K and A5RK. The station capacity is limited due to the existing metalclad breakers and LV cables. The forecasts indicate that King Edward TS will exceed its winter LTR by approximately 9 MW as early as 2026 and its summer LTR by about 1 MW in 2033. Under the high-growth scenario, the need dates advance significantly to 2025 for winter and 2030 for summer.

The proposed solution involves upgrading the metalclad breakers and LV cables to increase station capacity and support future downtown demand. This upgrade project is tentatively planned for an in-service date of 2033. In the interim, coordination with LDCs will be required to explore load transfer options to manage short-term capacity limitations until the upgrades are completed should there be any issues at the station.

8.2.9 Nepean TS T3/T4

Nepean TS is supplied from 230 kV circuit M32S and steps down voltage to 44 kV for local Hydro Ottawa customers. Regional load forecasts indicate that Nepean TS is expected to exceed its winter LTR by approximately 9 MW in 2030, while summer LTR is projected to remain within limits throughout the study period. Since this need is primarily in the winter timeframe, the TWG recommends monitoring winter load growth and revisiting this capacity need in the next regional planning cycle which can be triggered in advance if load growth is significant.

8.2.10 Riverdale TS T2/T3

Riverdale TS T2/T3 is a 45/75 MVA 115 kV/13.2 kV facility located in downtown Ottawa, supplied by three 115 kV circuits: A5K, A3RM, and A6R. The forecasts indicate that Riverdale TS will exceed its summer LTR by approximately 2 MW in 2030 and its winter LTR by about 9 MW in 2028. Under the high-growth scenario, the summer need date advances to 2029 and the winter need date to 2026.

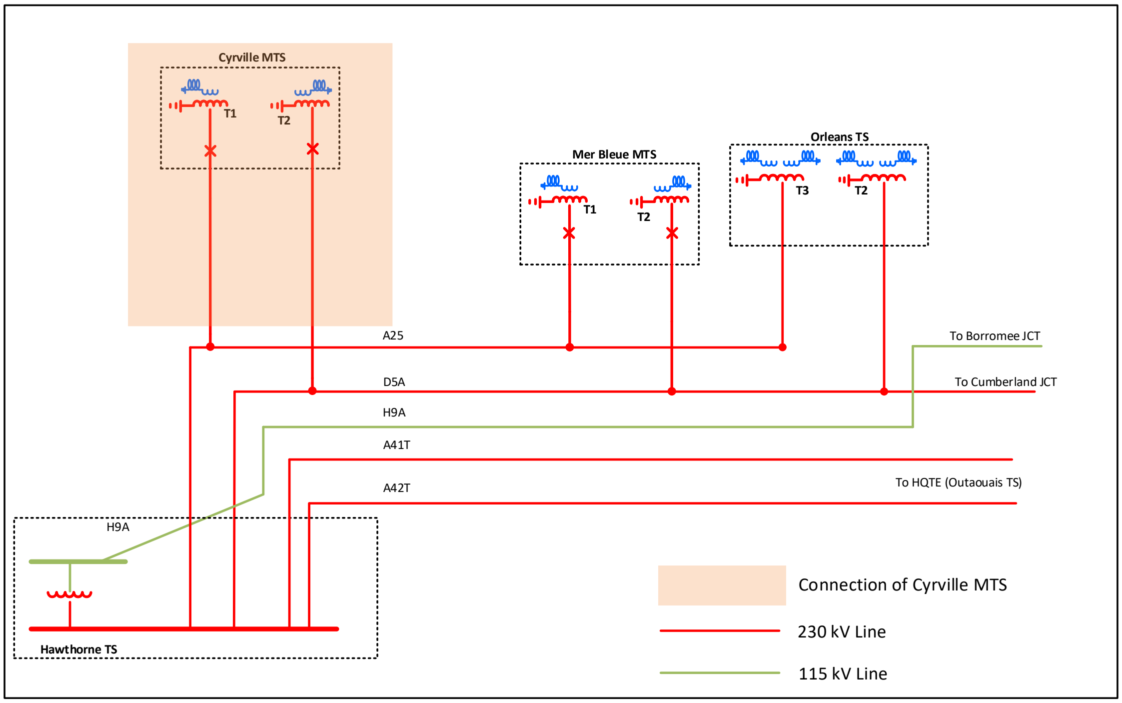
The station's transformation capacity is limited due to LV cables. Replacing the LV cables will provide additional capacity, enabling Riverdale TS to support projected load growth and relieve constraints in the Core East area. However, Hydro Ottawa has confirmed that some load transfers to nearby stations are available, which can help manage growth in the foreseeable future. Therefore, TWG recommends monitoring load growth at Riverdale TS and proceed with distribution load transfers as necessary until further upgrades are deemed required.

8.2.11 Cyrville MTS

Cyrville MTS is currently supplied by 115 kV circuits A4K and A2. The forecasts indicate that Cyrville MTS will exceed its summer LTR by approximately 1 MW in 2028 and its winter LTR by about 1 MW in 2030. Under the high-growth scenario, the winter need date advances to 2028.

The current plan as recommended in IRRP is to convert Cyrville MTS from a 115 kV station to a 230 kV station with two 100 MVA transformers by connecting to existing circuit D5A and a new 230 kV circuit A25 from Hawthorne TS, with a tentative in-service date of 2029. The planned conversion of Cyrville MTS will not only address near-term capacity needs but also position the station to accommodate future electrification and resilience requirements for Ottawa's east end. Please refer to Figure 8-10 for the planned connection. Hydro One is working on feasibility study to determine the preferred corridor for the connection of the station to the 230kV in collaboration with Hydro Ottawa.

Figure 8-10: New Cyrville MTS connected to D5A and new A25 circuit



8.2.12 Moulton MTS

Moulton MTS has a LTR of 32 MW in both summer and winter seasons. The forecasts indicate that the station will exceed its summer LTR by approximately 5 MW and its winter LTR by about 6 MW by 2028. To address this need, TWG has recommended to repurpose two 50 MVA, 115 kV transformers from Cyrville MTS following its planned conversion to 230 kV. Relocating these transformers to Moulton MTS will provide additional transformation capacity to meet projected demand growth. This approach leverages existing assets efficiently while supporting reliability in the growing east-end area.

8.2.13 Marionville DS

Marionville DS is forecasted to exceed its summer and winter Planned Loading Limit (PLL) as early as 2025.To address this need, the recommended action is to install a second transformer rated at 20 MVA and construct approximately 4.2 km of new distribution feeder to integrate the additional capacity. The tentative in-service date for this upgrade is December 2029. In the interim, Hydro One Distribution will manage load growth through transfers to nearby stations to maintain reliability until the new transformer and feeder build are completed.

8.2.14 Greely DS

Greely DS is projected to reach its summer and winter PLL in 2025. To address this the recommended action is to install SCADA fan monitoring for transformers T1 and T2 (115 kV to 28 kV). This upgrade will enable fan monitoring and allow higher ratings for both transformers, increasing their capacity from 23 MVA to 38 MVA in summer time and 28 MVA to 43 MVA in winter. The planned in-service date for SCADA fan monitoring is scheduled for 2026.

8.2.15 Manotick DS

Manotick DS has a summer PLL of 8.6 MVA and a winter PLL of 11.6 MVA. This PLL considers the loss of one transformer. Load forecasts indicate that the station will exceed these limits in both summer and winter starting in 2025.

Hydro One Distribution has operating measures to deal with station load in the near and medium term should one of the transformers fail such as use of Mobile Unit Substation (MUS)

Other measures such as Scada fan monitoring can be considered and will be reviewed as a part of next regional planning cycle.

8.2.16 Hinchey TS

Load forecasts indicate that Hinchey TS is expected to exceed its winter LTR by approximately 2 MW in 2031, while summer LTR is projected to remain within limits throughout the study period. Since this need is primarily in the winter timeframe. TWG is recommending monitoring winter load growth and revisiting this capacity need in the next regional planning cycle which can be triggered in advance if load growth is significant.

8.2.17 Rockland DS

Rockland DS is forecasted to reach its summer PLL in 2025, TWG recommends the implementation of SCADA monitoring of transformer fan. This will increase the summer PLL to 14.4 MVA and alleviate the overload at station. The planned in-service date for the fan monitoring installation is 2026.

In the interim, LDCs will implement operational measures, to manage loading and maintain system reliability until the permanent solution is in place.

8.2.18 Rockland East DS

Rockland East DS is forecasted to reach its summer PLL in 2026. TWG recommends the implementation of SCADA monitoring for transformer fans. The planned ISD for the fan monitoring installation is 2027.

In the interim, LDCs will implement operational measures to manage loading and maintain system reliability until the permanent solution is in place.

8.2.19 Additional Transformation Capacity needs

Several stations in the Greater Ottawa area are forecasted to exceed their LTR within the study period. The following summarizes the anticipated capacity needs:

- Nepean Epworth MTS – Expected to exceed its LTR in 2028 (winter) and 2035 (summer).
- Kanata MTS – Projected to exceed its summer and winter LTR in 2025.

- Ellwood MTS – Forecasted to exceed its summer and winter LTR in 2027.
- Limebank MTS – Expected to exceed its LTR in 2028 (winter) and 2031 (summer).
- Bridlewood MTS – Projected to exceed its LTR in 2030 (winter) and 2035 (summer).
- Marchwood MTS – Anticipated to exceed its summer and winter LTR in 2025.
- Centrepoint MTS – Expected to exceed its LTR in 2027 (winter) and 2032 (summer).
- Manordale MTS – Forecasted to exceed its LTR in 2026 (winter and summer).
- Fallowfield MTS – Projected to exceed its LTR in 2030 (winter) and 2026 (summer).

Hydro Ottawa has confirmed that loading at these stations can be managed through operational load transfers to nearby stations in the near term. Additionally, the commissioning of new stations—Kanata North MTS, Mer Bleue MTS, Greenbank MTS, Bronson MTS and Piperville MTS—will allow permanent load shifts, providing long-term relief to these stations and addressing regional capacity needs.

8.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period **2025-2044** for the 230kV and 115kV Transmission line circuits in the **Greater Ottawa region** by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater to this need. Based on the results, the following line capacity needs have been identified during the study period:

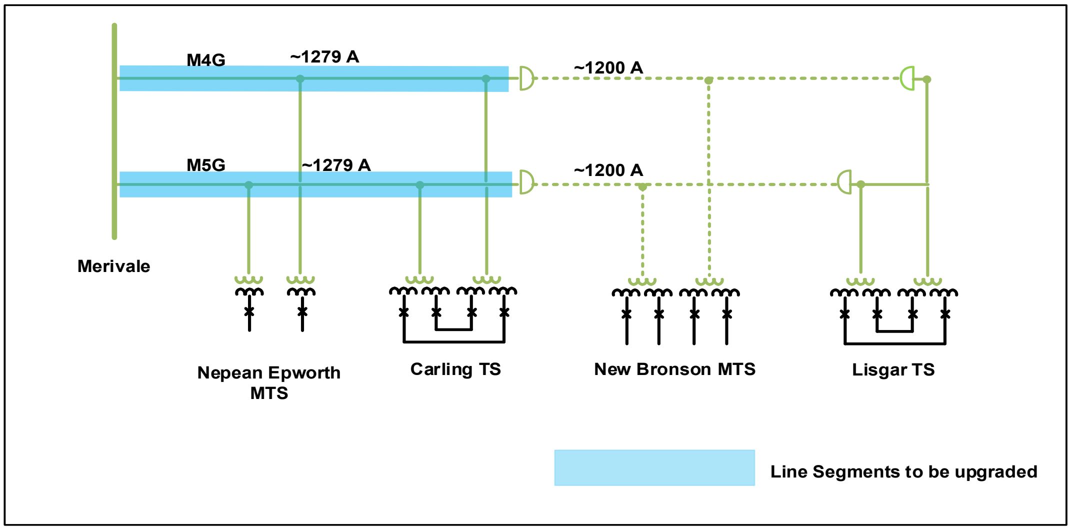
8.3.1 M4G/M5 – 115 kV – Section Uprate

The M4G and M5G circuits, which supply Nepean Epworth MTS, Carling TS and Lisgar TS, are forecasted to experience thermal constraints under contingency conditions as downtown Ottawa load continues to grow. When one circuit is out of service, the remaining circuit would be required to fully supply all stations, resulting in thermal overload conditions. Based on the regional load forecast, this limit is expected to be reached in the summer of 2030 and in the winter of 2032.

To address this issue, the recommended action is to upgrade sections of M4G and M5G between Merivale TS and Carling TS to remove thermal constraints and support higher downtown load.

Based on studies, this load pocket can supply about 360 MW before voltage issues arise. Hydro One will consider different conductor options to meet this load. The feasibility of using ACSS (Aluminum Conductor Steel Supported) conductor options will be explored to provide sufficient capacity while maintaining reliability.

Figure 8-11: Uprate Section from Merivale TS to Carling TS

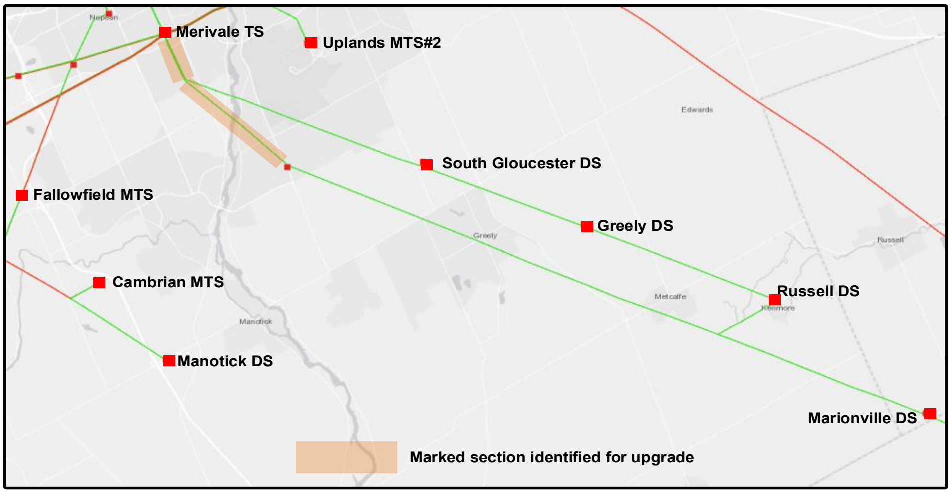


Regional planning emphasizes that downtown Ottawa is a critical load pocket with limited space for new infrastructure, making reinforcement of existing transmission corridors essential. Since Bronson MTS is also planned as a new station to relieve downtown capacity constraints, uprating the M4G/M5G corridor is a key enabler for this project and for supporting long-term growth in the Core East area.

8.3.2 L2M – 115 kV – Uprating Merivale TS x Limebank MTS

Thermal constraints have been identified on the L2M transmission line section between Merivale TS and Limebank MTS, which supplies Limebank MTS and Marionville DS as shown in Figure 8-12. These constraints are primarily driven by the increasing load forecast at Limebank MTS, as identified in the regional planning load forecast. The section of L2M has a summer rating of 93 MVA (477 A) and based on the study results, the 7.8km line section between Merivale TS and Limebank MTS is expected to reach its thermal capacity limit in the near term by 2028.

Figure 8-12: Uprate Section from Merivale TS to Limebank MTS



Alternative 1 - Remove sag limitation

The rating of circuit L2M between Merivale TS and Limebank MTS is currently limited due to clearance concerns. This option looks to increase the thermal capacity of L2M by addressing the conductor's sag issue. Hydro One has previously reviewed the work necessary to remove the limitation and has determined that approximately 3.2km of the line section would have to be rebuilt in addition to modification to some existing towers and insulators where no rebuilding is required. This work would remove the clearance limitation and would allow the circuit capacity to be increased to approximately 106MW in summer and 131 MW in winter. This allows us to meet the demand up to the mid-term.

Alternative 2: Rebuild the circuit

This alternative would look at rebuilding the 7.8km circuit L2M between Merivale TS and Limebank MTS to increase the circuit's thermal rating. Two options were considered.

Alt 2a: This option would rebuild the existing 7.8km as a single circuit 115kV line. It would address the thermal rating constraint currently on the circuit and would be adequate to supply the forecasted load of Marionville DS and Limebank MTS. However, with this option, Limebank MTS and Marionville DS would remain on a single circuit supply.

Alt 2b: This option would rebuild the existing 7.8km as a double circuit 115kV line. Similar to Alternative 2a, this option would address the thermal rating issue. This option would also help improve the reliability of supply to Limebank MTS by providing a second supply to the station.

Recommendation

TWG recommends uprating L2M to support the south-end growth and align with recommendations for proactive reinforcement of critical transmission corridors. A feasibility study will be done after which Hydro One and LDCs will review the different options. The selected alternative will follow the recommendation to uprate the section of L2M from Merivale TS to Limebank MTS, with a tentative in-service date of 2032.

8.3.3 A4K – 115 kV

Hawthorne TS x Overbrook TS section

Under the winter peak forecast for 2032, thermal overload has been identified on a critical section of the A4K corridor, specifically between Hawthorne TS x Overbrook TS, under the contingency of either circuit A5RK or A6R. When either of the circuits are out of service, the resulting increased loading on A4K is beyond its thermal capability.

Overbrook TS x King Edward TS section

This section is an underground cable section, and it exceeds its capacity due to King Edward TS being overloaded beyond the capacity described in section 8.2. If the station load is to increase as per the winter forecast, the upgrades to the station (beyond what is described in section 8.2) would have to be done in coordination with upgrades to cables.

TWG has reviewed the overload scenarios, and the recommended approach is to monitor load growth of the stations on A4K over the coming years. As demand continues to increase, TWG will reassess the situation and develop an appropriate action plan, which may include options such as reconductoring, circuit upgrades, or alternative reinforcement strategies to ensure compliance with thermal limits and maintain system reliability.

8.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, and to provide a median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net load forecast and the loss of one element over the study period 2025-2044 to cater for this need**.** Based on the results, the following system reliability, operating and restoring issues have been identified for this Region.

8.4.1 Load Security issue due to contingency of M32S

Nepean TS currently relies on a single 230 kV transmission supply circuit (M32S) from Merivale TS to South March TS. Under an M32S contingency, the entire load at Nepean TS would be lost due to configuration. According to ORTAC criteria, load security requires that no more than 150 MW of load can be lost for a single element contingency. While this limit is not exceeded in the summer forecast, it is projected to be reached in the winter forecast by 2029, when Nepean TS's peak demand is expected to surpass 150 MW. This creates a load security concern, as an outage of M32S would result in a full load loss, violating ORTAC requirements.

To address this issue, the recommended plan includes providing Nepean TS with a second transmission supply circuit originating from Merivale TS. This will ensure compliance with ORTAC and enhance the station reliability. The timing of this plan will be determined based on ongoing load monitoring and coordination with the Merivale TS upgrade project.

8.4.2 New Switching Station to improve reliability and flexibility in Kanata Area

As discussed in Section 8.2, one of the recommended plans includes the development of a new 230 kV Kanata North MTS, which will initially connect to the existing 230 kV circuit C3S. To enhance reliability, a second supply will be brought from M32S. This second supply will be enabled by rebuilding one of the existing transmission lines in the C7BM/C3S/W6CS corridor to double circuit 230kV line, thus connecting M32S to the new Kanata North MTS.

With the addition of Kanata North MTS and potential load transfers from Marchwood MTS and Kanata MTS, the summer and winter load forecasts were preliminary revised for the stations in the Kanata area as shown in Tables 8-3 below.

Table 8-3: Updated summer and winter load forecast (in MW) with preliminary transfers to Kanata North Considered

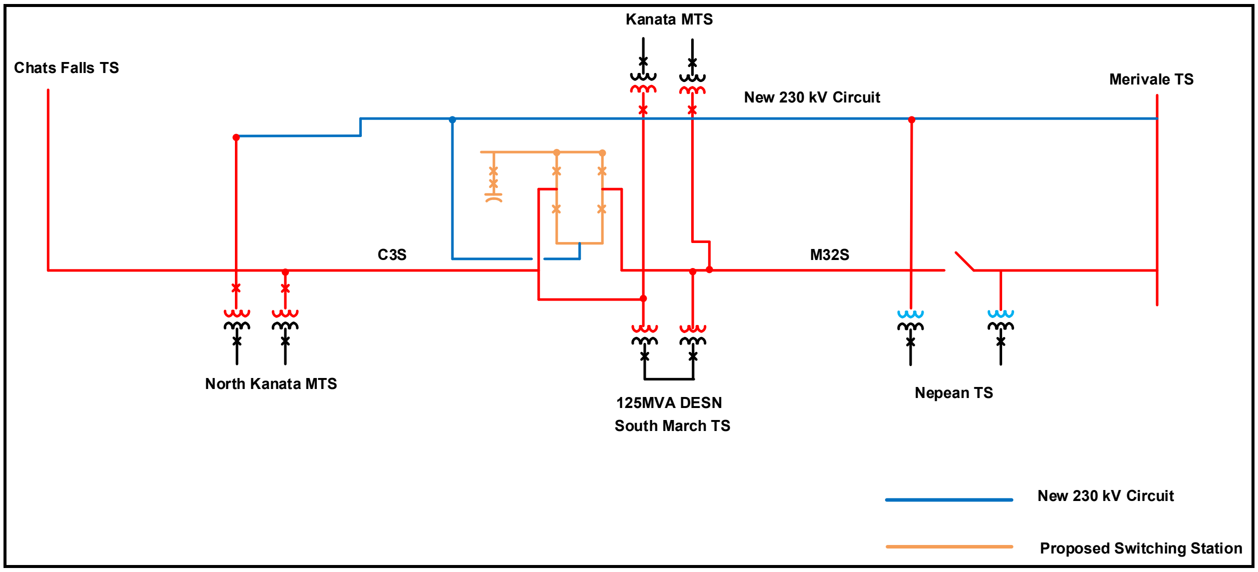
SUMMER											
Station	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
KANATA MTS	37	36	36	36	36	36	36	35	36	36	36
NEPEAN TS	127	128	128	128	128	128	128	129	129	130	131
SOUTH MARCH TS	112	112	114	122	121	122	126	127	128	129	130
Kanata North MTS	38	38	39	39	39	40	40	40	41	41	41
Load in 230 kV area	314	314	317	325	324	325	330	331	333	336	338
WINTER											
	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
KANATA MTS Revised	49	50	52	54	57	59	61	63	65	67	69
NEPEAN TS	148	159	169	176	184	191	198	205	214	223	231
SOUTH MARCH TS	119	124	132	143	147	151	158	162	168	173	179
Kanata North MTS	38	38	39	39	39	40	40	40	41	41	41
Load in 230 kV area	354	371	392	412	427	440	457	471	488	504	520

Analysis of contingencies on the 230 kV system indicates that stations supplied by these circuits can reliably support up to 340 MW of load while maintaining system performance. This threshold is expected to be reached under the summer forecast by 2038 and under the winter forecast as early as 2028.

To address this emerging constraint, the current strategy is to monitor winter load growth closely while advancing plans for a new switching station in the Kanata area. This switching station will facilitate flexible interconnections among Chats Falls TS, Merivale TS, South March TS, Nepean TS, and the new Kanata North MTS, thereby providing support for additional capacity, operational flexibility, and improved resiliency for the regional network. The conceptual layout of this switching station and its integration into the transmission system is illustrated in Figure 8-13.

The line that is planned from Merivale to Nepean as described in section 8.4.1 can be extended to the new switching station.

Figure 8-13: Proposed new 230 kV Line along with Switching Station



8.4.3 Load Security issue due to contingency of M1R+L2M

Merivale TS currently supplies two 115 kV circuits, M1R and L2M, which share a common breaker position. This configuration creates a common-mode outage risk: the loss of either circuit results in both circuits being tripped. Under ORTAC criteria, load security requires that no more than 150 MW of load can be lost for a single element contingency. While this limit is not exceeded in the summer forecast until 2040, it is projected to be reached in the winter forecast by 2031. This creates a load security concern, as an outage of either circuit would result in a full loss of supply to connected stations, violating ORTAC requirements.

To address these issues and improve reliability, the plan includes installing a new breaker at Merivale TS to separate circuits M1R and L2M into two independent 115 kV paths. This will eliminate the common-mode outage risk and ensure compliance with ORTAC load security criteria. The timing of this plan is driven by the emerging winter load security need, with a targeted in-service date of 2032. This solution also supports long-term thermal performance and operational flexibility. Figure 8-14 shows the 115 kV yard at Merivale TS following completion of Merivale TS upgrade project and Figure 8-15 shows the split M1R/L2M configuration that will be providing a separate breaker position for each line.

Figure 8-14: 115 kV Merivale TS after Merivale TS upgrade project

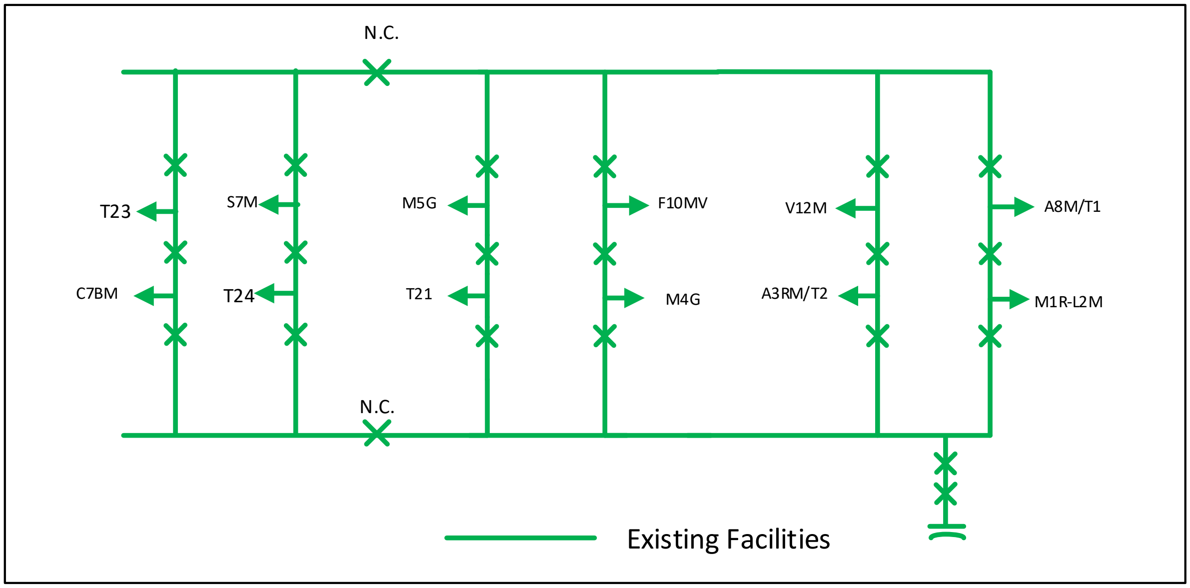
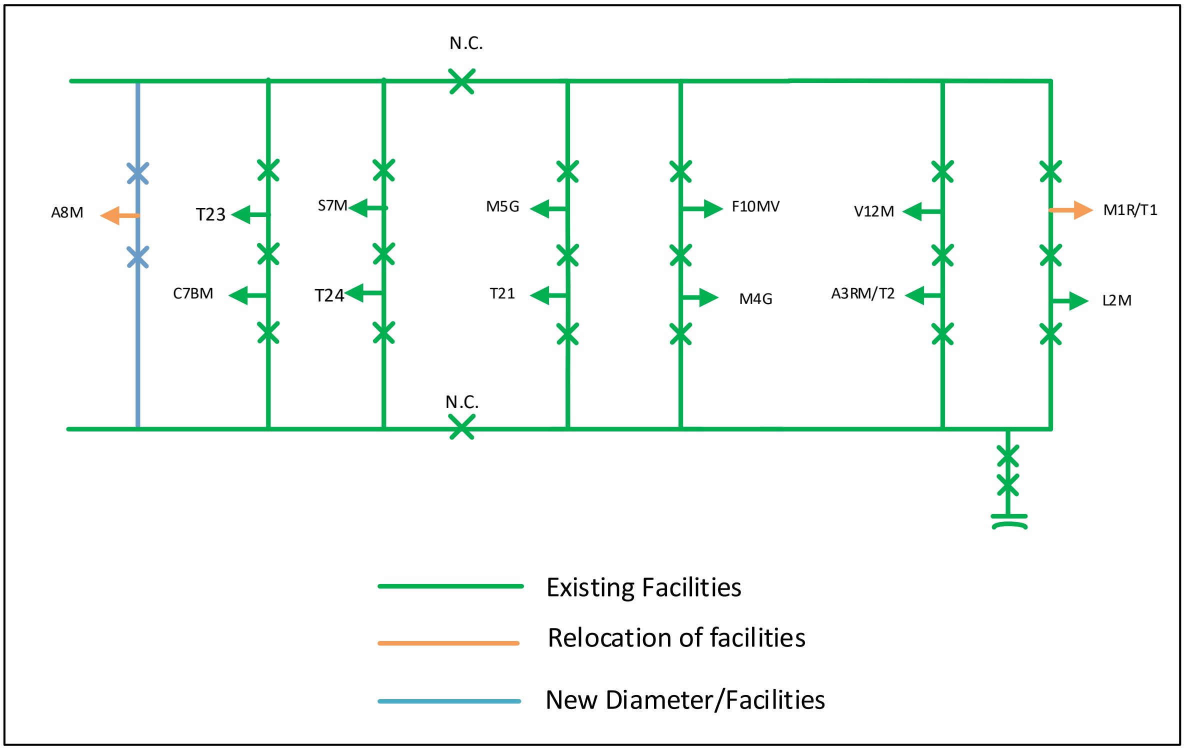


Figure 8-15 Different breaker positions of M1R and L2M



8.4.4 Loading and Voltage issues on S7M

Under the medium-term planning horizon, there is a limitation on the amount of load that can be transferred from Cambrian MTS to S7M under the contingency of E34M. This constraint arises due to both loading and voltage performance issues observed on S7M when additional load from Cambrian MTS is transferred to it during contingency conditions.

To address these challenges, several options are being considered. One potential solution is the planned conversion of S7M to 230 kV, which would significantly improve its capacity and voltage performance under contingency scenarios. Another option is to explore reactive power (VAR) support as load continues to grow, which could help maintain acceptable voltage levels and system stability. At this stage, the recommendation is to continue monitoring load growth and system performance, and to review the needs as part of the next cycle of regional planning. Ongoing bulk study may make recommendations that could impact the area, such as 230kV conversion.

8.4.5 Supply to East Ottawa

In the previous regional planning cycle, the recommended plan for the East Ottawa area included refurbishment of Bilberry Creek TS and the addition of two new feeder breakers. While the Greater Ottawa regional planning process was inactive, new information related to load growth and system conditions prompted a re-evaluation of the supply plan. In 2023, the TWG reviewed updated growth expectations for the area, the sustainment need at Bilberry Creek TS, and the capability of the 115 kV system to support future growth. Based on this review, TWG agreed to revise the recommendations for the area.

TWG's revised plan and new recommendation includes three components.

Retirement of Bilberry Creek TS

The TWG recommends retiring Bilberry Creek TS due to aging infrastructure and associated sustainment requirements. The revised approach shifts supply for the area away from continued reinvestment at Bilberry Creek TS resulting in removing load from 115 kV system and instead transitioning the connected load to the 230 kV system to support longer-term capacity and system reliability.

Upgrade at Orleans TS

As part of this approach, Orleans TS will be upgraded from dual supply 230/27.6 kV and 115/27.6 kV to 230/27.6 kV DESN. This upgrade includes a new 230 kV circuit A25 between Hawthorne TS and Orleans TS (~11km). The planned in-service date for the Orleans TS upgrade and the A25 circuit is June 2029.

Connection of new Mer Bleue MTS

The revised plan also includes the connection of a new Hydro Ottawa station, Mer Bleue MTS, to the 230 kV system. Mer Bleue MTS will be connected to 230 kV circuits D5A approximately 10 km east of Hawthorne TS, with a planned in-service date of July 2027. The project is also planned to connect to circuit A25 with an expected in-service date of June 2029.

This new recommendation provides the following benefits:

i. Addresses the Limited growth available on the 115kV system. The Ottawa 115kV system is mainly supplied via 250MVA autotransformers at Hawthorne TS and Merivale TS. East Ottawa 115kV system is connected to Hawthorne TS and most of its supply is from the station's autotransformers. These autotransformers are heavily loaded and limit the growth that can supplied from 115kV. Installing additional autotransformers at the station will be very challenging due to space constraints and short circuit level considerations. As such removing load from the 115kV system and transferring it to the 230kV wherever possible, helps preserve the current capacity on the 115kV to address the growth at existing stations that cannot be converted to 230kV at reasonable cost. This Project helps by reducing the 115kV loading and transferring the load to 230kV.

ii. The Project avoids significant refurbishment work at the station as the load can be transferred onto the 230kV system and Bilberry Creek TS can be retired instead of refurbished. In addition, there is also limited growth available at Bilberry Creek even if the station is refurbished.

iii. Orlean TS will no longer be subject to momentary interruptions due to its configuration.

iv. The new 230kV circuit will allow more growth and improve supply reliability in the Orleans area. Currently connection on the 230 kV in the Orleans area will have to be limited to 100 MW. With the new circuit the area can support over 300 MW.

The RIP concludes that retiring Bilberry Creek TS, upgrading Orleans TS, and completing the associated 230 kV circuit and station connections is the most cost-effective option to address the long-term needs in East Ottawa. This combined set of projects is being pursued as an alternative to the sustainment and upgrade work at Bilberry Creek TS that was recommended in the previous regional planning cycle.

From a reliability perspective, the revised plan reduces dependence on aging station equipment, increases supply robustness by serving the area from the higher-capacity 230 kV network, and improves operational flexibility during planned outages or contingencies by enabling better load restoration options across the East Ottawa supply area.

Figure 8-16 Existing Orleans Area

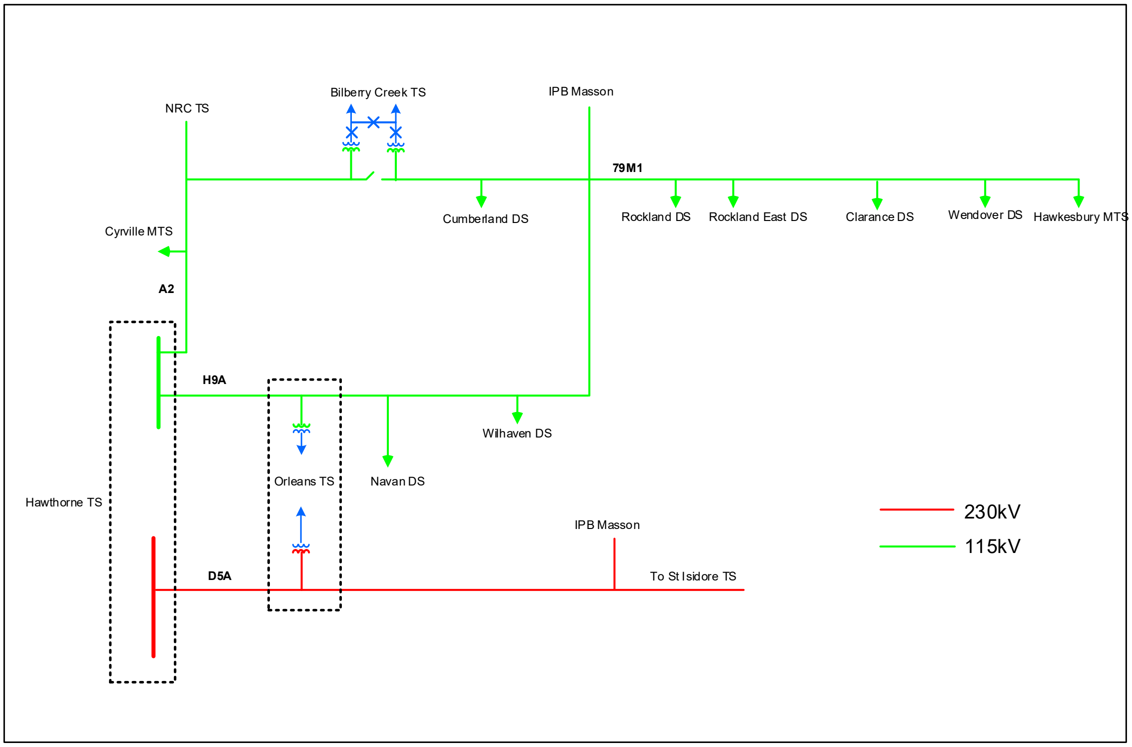
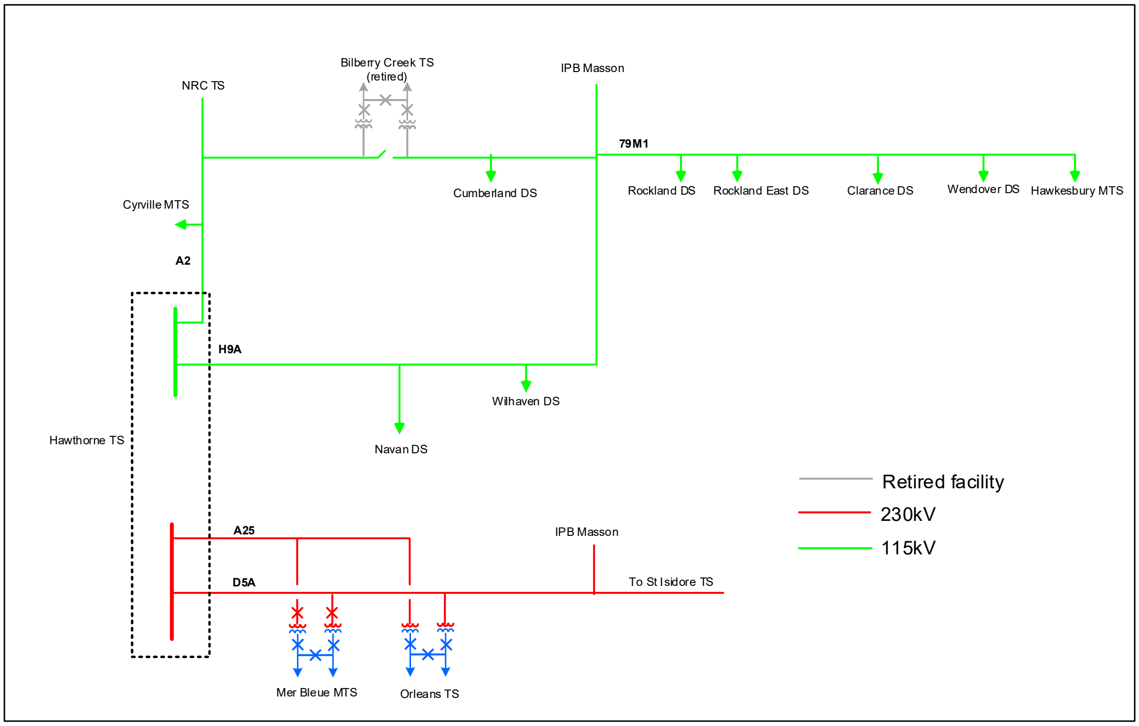


Figure 8-17 Orleans Area after Upgrade



9. CONCLUSION AND RECOMMENDATION

This section concludes the Regional Infrastructure plan Report for the Greater Ottawa region. The Major Infrastructure investments recommended by the TWG in the near and mid-term planning horizon 2025-2044 are provided in Table 7 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 9: Recommended Plans over the next 10 Years

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Budgetary Cost ($M)
Asset Renewal Needs				
South March TS	Replacement of T1/T2 transformers with upgraded units based on asset conditions and capacity needs.	Hydro One	2029	$40M
Albion TS	Replacement of T1/T2 transformers with upgraded units based on asset condition and capacity needs.	Hydro One	2031	$60M
Nepean TS	Replacement of T3/T4 transformers based on asset condition	Hydro One	2034	$30M
S7M	Refurbishment of line section between Manotick JCT x Richmond South MTS and S7M 673N x Manordale JCT	Hydro One	2030	$5M
Station Capacity Needs				
South March TS	Replacement of T1/T2 transformers with upgraded units based on asset conditions and capacity needs.	Hydro One	2029	$40M
Carling TS	Replacement of limiting LV cables.	Hydro One	2030	$10M

Lisgar TS	Replacement of T2 transformer and LV cables/breakers - Greenfield	Hydro One	2034	$50M
	Replacement of T2 transformer and LV cables/breakers – In Situ	Hydro One	2031	$30M
King Edward TS	Replacement of LV cables and breakers.	Hydro One	2033	$20M
Cyrville MTS	Station voltage conversion from 115kV to 230kV to increase station rating and upgrade station transformation capacity.	Hydro One/ Hydro Ottawa	2029	$85M*
Moulton MTS	Relocate 50 MVA ,115kV transformers from Cyrville MTS after voltage conversion to increase station rating at Moulton TS.	Hydro Ottawa	2029	$5M
Bronson MTS	Build a new 115kV Transformer Station east of Carling TS by converting existing Bronson distribution station	Hydro One/ Hydro Ottawa	2031	$110M*
Greenbank MTS	Build new Transformer Station to meet demand growth and need for 28kV supply west of Merivale TS.	Hydro One/ Hydro Ottawa	2028	$100M*
Kanata North MTS	Build a new Transformer Station by connecting 230 kV C3S and new transmission line from South March TS	Hydro One/ Hydro Ottawa	2028	$100M*
Marionville DS	Install a second transformer to increase station rating.	Hydro One Dx	2029	$12M*
Greely DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2026	$2M*

Rockland DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2026	$2M*
Rockland East DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2027	$3M*
Transmission Line Capacity Needs				
M4G/M5G	Uprate Line section between Merivale TS x Carling TS	Hydro One	2030	$30M
L2M	Uprate line section between Merivale TS x Limebank JCT	Hydro One	2032	$30M
System Reliability, Operation and Load restoration Needs				
Kanata Area	Kanata Area Transmission Reinforcement	Hydro One	2033	$250M
Nepean TS – Load Security Criteria	Second 230 kV Supply to station	Hydro One	2032	$70M
M1R+L2M	Split Breaker position for M1R and L2M at Merivale TS	Hydro One	2032	$45M
East Ottawa Area	Supply to East Ottawa	Hydro One	2029-2030	$165M*

* These investment costs include associated distribution system costs.

Note:

a) The planned in-service dates are tentative and subject to change.
b) Costs are high-level planning estimates and actual costs may vary.

10. REFERENCES

[1] Hydro One, RIP Report – Greater Ottawa (Second cycle), published on December 18, 2020

[2] Hydro One, NA Report – Greater Ottawa (Third cycle), published on December 20, 2022

[3] Independent Electricity System Operator, SA Report – Greater Ottawa (Third cycle), published on March 21, 2023

[4] Independent Electricity System Operator, IRRP Report – Ottawa Area Sub-region (Third cycle), published on July 31, 2025

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

[6] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. March 31, 2025)

[7] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. September 16, 2025)

[8] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer/Winter Weather Adjusted Net Load Forecast

Table A.1: Greater Ottawa region – Summer - Reference Load Forecast

Name of Station	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
ALBION TS	86.5	58.6	59.2	59.7	60.3	60.7	61.2	61.9	62.6	63.5	64.5	65.2	65.5	65.9	66.4	66.8	67.2	67.8	68.4	69.0	69.0
ALMONTE TS	96.7	55.4	56.1	56.7	57.4	58.0	62.4	63.8	64.9	68.4	71.8	72.8	74.1	75.4	76.8	78.1	79.6	81.0	82.5	83.9	85.5
ARNPRIOR TS	54.9	39.5	39.8	39.9	40.7	41.3	44.2	47.3	48.6	48.9	49.3	49.8	50.4	51.0	51.6	52.2	53.0	53.7	54.3	54.9	55.6
BILBERRY CREEK TS	85.3	64.0	64.2	64.4	14.3	14.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BRIDLEWOOD MTS	23.5	21.7	22.0	22.2	22.4	22.6	22.8	22.9	23.1	23.2	23.4	23.6	23.5	23.7	23.7	23.7	23.7	23.9	24.2	24.4	24.4
CAMBRIAN MTS	114.0	58.9	62.7	68.3	71.9	74.7	77.1	80.6	84.2	87.8	91.4	95.1	99.1	101.8	102.3	102.5	103.0	103.7	104.4	105.1	105.8
CARLING TS	95.0	89.2	90.6	91.6	105.9	106.6	113.8	126.4	139.2	139.6	140.0	141.2	140.9	140.9	141.1	141.3	141.4	142.6	143.7	144.9	144.9
CENTREPOINT MTS	13.3	12.8	12.9	13.0	13.0	13.1	13.1	13.2	13.4	13.5	13.7	13.8	13.9	14.0	14.1	14.2	14.3	14.6	14.8	15.1	15.1
CLARENCE DS	7.8	2.6	2.6	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.3	3.4	3.5
CUMBERLAND DS	6.8	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.6	6.7	6.8	6.9	7.0	7.2	7.3	7.4	7.5	7.7	7.8
CYRVILLE MTS	47.5	31.9	34.1	35.0	48.4	49.1	49.0	49.1	49.0	49.2	49.2	49.4	49.8	50.2	50.6	50.5	50.5	50.8	51.2	51.5	51.9
ELLWOOD MTS	47.0	41.7	45.0	47.3	48.4	49.4	49.4	49.3	49.2	49.3	49.2	49.3	49.6	49.9	50.2	50.4	50.7	51.1	51.4	51.8	52.2
FALLOWFIELD MTS	27.2	24.1	27.3	30.5	33.1	33.3	33.3	33.3	33.4	33.3	33.2	33.3	33.5	33.7	33.8	33.8	34.0	34.2	34.5	34.7	35.0
GREELY DS	20.7	22.4	22.6	22.9	23.2	23.4	23.9	24.2	24.5	24.9	25.2	25.9	26.6	27.6	28.4	29.3	30.1	30.6	30.9	30.9	30.9
HAWKESBURY MTS #1	18.0	12.1	12.3	12.4	12.6	12.7	12.9	13.0	13.1	13.2	13.4	13.6	13.9	14.1	14.4	14.7	15.0	15.3	15.6	15.9	16.2
HAWTHORNE TS	144.8	136.6	137.1	137.3	138.0	138.4	139.1	139.6	140.2	141.0	141.7	143.1	143.8	144.7	145.7	146.5	147.4	148.1	148.7	148.6	148.7
HINCHEY TS	85.6	21.6	22.2	28.6	36.5	40.9	44.8	47.7	49.6	50.9	51.7	52.3	52.3	52.3	52.3	52.2	52.2	52.7	53.2	70.3	70.8
HYDRO RD MTS	114.0	-	-	13.0	18.5	23.9	29.3	32.9	36.5	40.0	43.6	47.2	47.7	48.2	48.6	49.1	49.6	49.8	50.0	50.2	50.2
CTS-1	100.0	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8
KANATA MTS	51.5	54.1	54.1	53.8	53.8	53.6	53.5	53.5	53.3	53.4	53.5	53.5	53.9	54.3	54.7	55.0	55.3	55.7	56.1	56.4	56.8
KING EDWARD TS	86.9	77.6	78.8	79.8	80.8	81.6	82.6	85.0	86.4	87.7	89.0	90.1	91.4	92.7	94.0	95.4	96.8	98.9	101.1	103.2	103.2
LIMEBANK MTS	75.0	50.9	57.2	63.1	68.6	71.5	73.7	75.8	77.8	79.5	80.7	82.0	83.6	85.2	86.9	88.5	90.1	90.8	91.4	91.9	92.6
LINCOLN HEIGHTS TS	99.4	46.4	46.7	46.9	47.0	47.1	47.3	47.8	48.3	48.9	49.5	50.0	50.1	50.3	50.5	50.7	50.9	51.5	52.1	52.7	52.7
LISGAR TS	83.4	78.5	80.2	81.5	96.6	97.7	98.9	109.8	109.8	109.8	109.9	110.7	109.9	109.2	108.6	108.0	107.4	107.7	108.0	108.3	108.3
LONGUEUIL TS	123.5	45.6	48.1	50.4	51.8	52.1	52.6	53.0	53.5	61.3	64.5	65.2	68.6	69.7	70.8	71.9	73.0	73.9	74.9	75.8	76.8

MANORDALE MTS	9.6	9.5	9.7	9.8	10.0	10.1	10.3	10.4	10.4	10.5	10.6	10.7	10.7	10.8	10.8	11.0	11.1	11.2	11.4	11.6	11.6
MANOTICK DS	7.7	10.5	10.7	10.8	11.0	11.1	11.3	11.4	11.6	11.8	12.0	12.3	12.5	12.8	13.1	13.3	13.6	13.9	14.2	14.6	14.9
MARCHWOOD MTS	32.3	51.3	52.2	52.9	54.1	55.5	56.7	58.0	59.2	60.7	61.5	61.5	61.8	62.2	62.5	62.9	63.2	63.6	64.0	64.4	64.8
MARIONVILLE DS	13.5	15.5	15.6	15.7	15.9	16.0	16.3	16.4	16.6	16.8	17.0	17.3	17.8	18.2	18.7	19.2	19.7	20.0	20.2	20.1	20.1
Mer Bleue MTS	114.0	-	-	-	65.3	66.0	66.7	67.4	68.2	69.0	69.9	70.7	71.3	72.0	72.8	73.5	74.2	75.2	76.3	77.3	77.3
MERIVALE MTS	32.9	18.3	18.2	18.0	17.8	17.6	17.4	17.5	17.6	17.7	17.8	17.9	17.9	17.8	17.8	17.8	17.8	18.0	18.2	18.4	18.4
MOULTON MTS	32.0	23.7	23.5	23.2	36.7	36.2	35.9	35.9	36.0	36.1	36.2	36.3	36.2	36.1	36.1	36.1	36.0	36.2	36.3	36.5	36.5
CTS-2	14.0	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5
NRC TS	77.4	5.1	5.1	5.0	17.1	16.8	16.5	16.4	16.4	16.3	16.2	16.0	15.8	15.8	15.8	15.8	15.8	15.7	15.7	15.7	15.7
NAVAN DS	13.5	5.0	5.1	5.1	5.1	5.1	5.1	5.2	5.2	5.3	5.3	5.4	5.5	5.6	5.7	5.8	5.8	5.9	6.0	6.1	6.1
NEPEAN EPWORTH MTS	12.9	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.7	12.8	12.9	13.0	13.0	13.0	13.1	13.1	13.1	13.3	13.5	13.6	13.6
NEPEAN TS	144.1	126.1	126.7	126.9	127.3	127.5	127.9	128.0	127.8	128.0	128.1	128.5	129.3	130.2	131.1	131.9	132.8	133.7	134.6	135.4	136.3
ORLEANS TS	118.2	118.5	123.0	120.3	123.8	126.6	143.9	146.9	149.8	151.6	153.5	155.7	158.3	160.2	162.1	163.9	165.8	167.7	169.5	171.3	173.2
OVERBROOK TS	116.8	86.1	88.3	90.2	92.2	94.0	95.9	96.8	97.9	98.9	100.0	101.1	101.7	102.4	103.2	104.0	104.8	106.5	108.2	109.8	110.8
PIPERVILLE MTS	108.0	-	2.3	4.6	6.8	9.0	11.2	11.4	11.7	11.9	12.2	12.4	12.7	13.1	13.4	13.8	14.1	14.4	14.6	14.8	14.8
RICHMOND SOUTH MTS	49.0	20.7	24.2	27.0	29.8	32.0	34.3	38.3	42.1	45.6	49.2	52.3	55.6	56.3	57.1	57.8	58.5	58.9	59.3	59.6	60.0
RIVERDALE TS	110.8	96.8	100.1	103.2	106.3	109.1	112.1	112.8	113.6	114.5	115.3	116.0	116.5	117.2	117.9	118.7	119.5	121.4	123.3	125.1	125.1
ROCKLAND DS	7.8	8.3	8.6	8.8	9.0	10.3	11.5	12.6	13.7	14.8	17.4	18.8	20.4	21.9	23.5	25.0	26.5	28.1	29.6	31.1	32.7
ROCKLAND EAST DS	15.5	15.3	15.9	16.4	16.9	17.4	18.0	18.5	19.0	19.6	20.1	20.7	21.3	22.0	22.7	23.3	24.0	24.7	25.1	25.4	25.8
RUSSELL DS	6.8	4.5	4.5	4.5	4.6	4.6	4.7	4.8	4.8	4.9	4.9	5.1	5.2	5.3	5.5	5.6	5.8	5.9	5.9	5.9	5.9
RUSSELL TS	72.7	72.0	76.6	78.8	78.9	79.0	79.1	79.4	79.9	80.3	81.0	81.4	81.5	81.6	81.8	81.9	92.2	92.4	92.8	93.1	93.1
SLATER TS	158.7	96.1	96.9	98.2	102.3	107.0	111.8	115.9	117.7	119.1	119.3	119.5	120.2	120.8	121.5	122.1	122.7	123.6	124.4	125.2	126.1
SOUTH GLOUCESTER DS	6.8	5.0	5.0	5.1	5.1	5.2	5.3	5.3	5.4	5.4	5.5	5.6	5.8	6.0	6.2	6.3	6.5	6.6	6.7	6.7	6.7
SOUTH MARCH TS	99.2	98.1	102.8	108.6	111.8	111.7	114.2	122.1	121.4	121.6	126.2	126.6	127.6	128.6	129.7	130.7	131.7	133.0	134.0	135.1	136.4
ST. ISIDORE TS	117.8	44.9	47.4	48.6	49.9	51.2	52.5	56.4	60.5	61.6	63.7	64.4	65.1	66.0	66.8	67.6	68.5	69.4	70.3	71.1	72.0
STEWARTVILLE TS	49.5	28.5	28.8	29.0	29.3	29.5	29.8	30.1	30.4	30.8	31.2	31.6	34.7	35.6	36.1	36.6	37.1	37.7	38.2	38.7	39.2
TERRY FOX MTS	91.7	63.3	64.2	64.9	65.7	66.4	67.2	67.0	66.9	66.9	66.9	67.0	66.7	66.5	66.3	66.0	65.9	66.3	66.8	67.3	67.8
UPLANDS MTS	57.6	29.4	33.3	40.7	43.2	44.8	45.6	46.3	47.0	47.7	48.4	49.2	50.2	50.9	51.7	52.4	53.1	53.4	53.8	54.1	54.5
WENDOVER DS	30.4	15.8	16.1	16.3	16.5	16.7	16.9	17.1	17.4	17.8	18.1	18.4	18.8	19.2	19.7	20.1	23.6	24.0	24.5	24.9	25.3
WILHAVEN DS	34.2	7.8	7.9	7.9	8.0	8.0	8.0	8.1	8.1	8.2	8.4	8.7	8.9	9.1	9.2	9.3	9.4	9.5	9.7	9.8	9.9
WOODROFFE TS	97.4	48.3	49.4	50.5	51.5	52.4	53.4	53.8	54.2	54.7	55.2	55.6	56.1	56.6	57.2	57.8	58.4	59.3	60.2	61.1	61.1

Table A.2: Greater Ottawa region –Winter - Reference Load Forecast

Name of Station	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
ALBION TS	101.7	59.8	65.7	71.5	77.3	82.8	88.4	92.3	96.2	100.2	104.2	108.1	112.9	117.8	122.5	127.0	131.7	136.2	140.6	145.0	145.0
ALMONTE TS	125.1	52.2	53.1	54.0	54.9	55.6	60.1	61.6	62.7	63.7	64.6	65.8	67.1	68.4	69.8	71.3	72.8	74.3	75.7	77.3	78.8
ARNPRIOR TS	59.4	39.4	39.8	40.2	41.1	41.9	42.2	42.7	44.1	44.5	45.0	45.6	46.2	46.9	47.6	48.3	49.0	49.8	50.4	51.2	51.9
BILBERRY CREEK TS	95.5	54.1	46.0	38.0	14.3	14.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BRIDLEWOOD MTS	23.5	17.1	18.7	20.3	21.9	23.4	25.0	26.1	27.3	28.5	29.7	30.9	32.2	33.6	34.9	36.2	37.6	38.9	40.3	41.7	41.7
CAMBRIAN MTS	123.5	43.7	48.4	52.9	67.3	71.5	75.6	79.0	98.8	102.2	105.7	109.2	112.1	115.0	117.8	120.6	123.5	127.7	131.9	136.2	136.2
CARLING TS	124.3	84.7	94.0	103.1	125.3	133.9	148.9	167.9	187.0	193.7	200.3	207.6	214.2	220.9	227.2	233.1	239.6	246.3	253.0	259.6	259.6
CENTREPOINT MTS	13.3	12.0	13.2	14.4	15.6	16.7	17.8	18.9	20.0	21.0	22.1	23.2	24.4	25.5	26.7	27.8	29.0	30.1	31.2	32.4	32.4
CLARENCE DS	10.5	2.2	2.3	2.3	2.3	2.4	2.4	2.4	2.5	2.5	2.6	2.6	2.6	2.7	2.8	2.8	2.9	2.9	3.0	3.1	3.1
CUMBERLAND DS	8.6	5.2	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.8	5.9	6.0	6.1	6.2	6.4	6.5	6.6	6.7	6.8	6.9
CYRVILLE MTS	47.5	31.6	35.1	38.5	41.9	45.2	48.4	50.6	52.7	54.9	57.1	59.3	62.1	65.0	67.8	70.5	73.3	75.7	78.1	80.5	83.6
ELLWOOD MTS	47.0	39.5	43.6	47.7	51.7	55.6	59.5	63.0	66.5	70.0	73.5	76.9	80.5	84.2	87.7	91.0	94.6	97.9	101.3	104.6	104.6
FALLOWFIELD MTS	27.2	13.3	15.8	18.3	22.8	25.2	27.5	29.7	31.8	34.0	36.2	38.4	42.1	45.9	49.7	53.3	57.1	59.4	61.7	64.1	64.1
GREELY DS	25.2	27.1	27.4	27.7	28.2	28.5	29.0	29.4	29.7	30.1	30.6	31.3	32.3	33.2	34.2	35.1	36.1	36.7	37.1	37.1	37.1
HAWKESBURY MTS #1	18.0	13.0	13.5	13.9	14.4	14.9	15.3	15.7	16.1	16.6	17.1	17.5	17.9	18.4	18.8	19.3	19.8	20.3	20.8	21.3	21.8
HAWTHORNE TS	171.6	132.7	140.4	147.7	155.2	162.4	169.8	177.3	184.8	192.5	200.1	207.9	214.9	222.1	228.8	235.2	242.2	248.1	253.8	236.3	236.3
HINCHEY TS	95.0	54.4	62.2	69.7	77.3	84.5	91.8	96.9	102.0	107.2	112.4	117.5	123.4	129.4	135.1	140.6	146.5	151.7	156.8	161.9	161.9
HYDRO RD MTS	123.5	-	-	10.0	14.3	18.5	22.8	25.6	28.5	31.3	34.1	37.0	37.9	38.8	39.7	40.6	41.6	42.0	42.4	42.9	42.9
CTS-1	100.0	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8
KANATA MTS	51.5	53.9	56.1	63.5	65.6	67.6	69.6	71.8	74.1	76.5	78.9	81.2	83.2	85.3	87.2	89.1	91.1	93.4	95.7	98.0	98.0
KING EDWARD TS	90.3	89.6	99.1	108.3	117.5	126.5	135.5	145.2	153.7	162.3	170.8	179.2	188.5	198.0	207.0	215.6	224.8	233.7	242.5	251.3	251.3
LIMEBANK MTS	75.0	60.9	66.8	72.6	78.4	83.9	89.4	92.9	96.5	100.1	103.9	107.6	111.4	115.3	119.1	122.9	126.7	130.6	134.5	138.4	138.4
LINCOLN HEIGHTS TS	113.1	53.8	59.0	64.0	69.1	73.9	78.7	82.5	86.2	90.0	93.9	97.7	102.3	106.9	111.4	115.8	120.3	124.2	128.2	132.1	132.1
LISGAR TS	105.1	77.0	84.6	91.8	112.8	119.8	126.8	143.3	148.8	154.4	159.9	165.3	171.3	177.3	182.9	188.2	194.1	199.5	205.0	210.4	210.4
LONGUEUIL TS	133.0	50.7	53.4	56.0	57.8	58.3	58.9	59.6	60.2	60.9	61.7	62.7	63.7	64.8	66.0	67.1	68.3	69.5	70.6	71.9	73.1
MANORDALE MTS	9.6	9.5	10.4	11.2	12.1	12.9	13.7	14.5	15.2	16.0	16.8	17.5	18.4	19.3	20.1	20.9	21.7	22.6	23.4	24.2	24.2

MANOTICK DS	10.4	12.0	12.1	12.2	12.4	12.5	12.8	12.9	13.1	13.3	13.5	13.8	14.2	14.6	15.0	15.4	15.8	16.1	16.3	16.3	16.3
MARCHWOOD MTS	32.3	32.5	35.4	38.3	41.2	43.9	46.7	48.6	50.5	52.5	54.5	56.5	58.8	61.1	63.3	65.4	67.7	69.7	71.7	73.7	73.7
MARIONVILLE DS	13.5	18.4	18.6	18.8	19.0	19.2	19.5	19.7	19.9	20.1	20.3	20.8	21.3	21.9	22.5	23.0	23.7	24.0	24.2	24.2	24.2
Mer Bleue MTS	123.5	-	-	-	75.4	81.3	87.2	91.5	95.8	100.3	104.8	109.2	114.0	118.9	123.6	128.3	133.1	138.0	142.9	147.8	147.8
MERIVALE MTS	37.3	15.4	17.3	19.1	20.9	22.7	24.5	25.8	27.2	28.7	30.1	31.4	33.0	34.7	36.2	37.7	39.3	40.7	42.2	43.6	43.6
MOULTON MTS	32.0	18.6	20.5	22.3	37.9	39.6	41.2	42.6	43.9	45.3	46.7	48.1	49.5	50.9	52.2	53.5	54.9	56.1	57.3	58.6	58.6
CTS-2	14.0	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6
NRC TS	87.7	6.1	6.0	5.9	20.3	20.0	19.7	19.6	19.6	19.5	19.4	19.2	19.0	18.9	18.9	18.9	18.9	18.9	18.8	18.8	18.8
NAVAN DS	13.5	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.5	4.6	4.6	4.7	4.7	4.8	4.9	5.0	5.0	5.1	5.2	5.2	5.3
NEPEAN EPWORTH MTS	12.9	10.1	11.1	12.0	13.0	13.9	14.8	15.6	16.5	17.3	18.2	19.0	19.9	20.8	21.6	22.5	23.3	24.2	25.0	25.8	25.8
NEPEAN TS	160.7	116.4	127.3	137.8	148.4	158.7	169.0	176.2	183.5	190.9	198.1	205.2	213.9	222.9	231.2	239.1	247.8	257.1	266.3	275.6	275.6
ORLEANS TS	134.5	78.2	78.0	77.6	70.6	73.3	90.5	93.3	96.1	97.8	99.6	101.5	103.6	104.8	106.0	107.1	108.4	109.6	110.7	111.9	113.1
OVERBROOK TS	135.6	87.7	96.6	105.2	113.8	122.2	130.6	138.2	145.8	153.5	161.1	168.5	176.4	184.3	191.8	199.0	206.7	214.2	221.6	228.9	228.9
PIPERVILLE MTS	117.0	-	3.0	5.9	8.8	11.7	14.5	15.5	16.4	17.4	18.4	19.4	20.8	22.2	23.6	25.0	26.4	27.4	28.4	29.4	29.4
RICHMOND South MTS	49.0	17.9	19.5	42.2	49.9	51.2	52.5	53.7	54.9	56.2	64.7	66.0	67.3	68.7	70.1	71.3	72.7	74.1	75.5	76.9	76.9
RIVERDALE TS	117.0	97.7	107.3	116.6	125.9	134.9	144.0	150.9	157.8	164.9	171.9	178.7	186.6	194.7	202.3	209.7	217.6	224.7	231.8	238.9	238.9
ROCKLAND DS	10.5	6.9	7.2	7.4	7.6	9.0	10.2	11.3	12.5	13.6	16.2	17.8	19.3	20.9	22.4	24.0	25.6	27.1	28.7	30.2	31.8
ROCKLAND EAST DS	20.9	12.4	13.0	13.6	14.2	14.7	15.3	15.8	16.3	16.9	17.4	18.0	18.6	19.2	19.9	20.5	21.2	21.9	22.2	22.5	22.8
RUSSELL DS	8.6	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.8	5.9	6.1	6.2	6.4	6.6	6.8	6.9	7.1	7.1	7.1	7.1
RUSSELL TS	79.9	67.7	78.5	86.8	93.1	99.1	105.2	109.8	114.5	119.2	123.9	128.5	133.5	138.6	143.3	147.8	163.0	167.6	172.1	176.6	176.6
SLATER TS	163.0	89.9	94.6	99.1	103.6	107.8	112.2	116.2	120.2	124.3	128.3	132.2	137.8	143.4	148.8	153.8	159.3	164.0	168.7	173.4	173.4
SOUTH GLOUCESTER DS	8.6	5.9	6.0	6.0	6.1	6.2	6.3	6.4	6.4	6.5	6.6	6.8	7.0	7.2	7.4	7.6	7.8	7.9	8.0	8.0	8.0
SOUTH MARCH TS	113.7	98.0	105.9	111.7	119.4	123.7	132.0	142.7	147.0	150.7	158.2	162.3	167.9	172.9	178.8	183.8	189.6	193.9	198.8	203.3	208.1
ST. ISIDORE TS	124.5	47.7	50.3	51.9	53.5	54.9	56.3	57.8	59.4	60.4	62.6	63.4	64.2	65.2	66.2	67.1	68.2	69.2	70.2	69.1	70.1
STEWARTVILLE TS	56.7	27.8	28.2	28.6	29.0	29.2	29.6	29.9	30.2	30.6	31.0	31.5	34.5	35.0	35.6	36.1	36.6	37.2	37.7	38.3	38.8
TERRY FOX MTS	105.8	50.3	55.5	60.5	65.5	70.3	75.0	79.0	83.1	87.2	91.4	95.6	100.6	105.6	110.6	115.5	120.5	124.8	129.1	133.4	133.4
UPLANDS MTS	65.8	25.9	28.6	31.2	33.9	36.4	38.9	41.0	43.1	45.3	47.5	49.6	51.8	54.1	56.2	58.3	60.5	62.7	64.8	66.9	66.9
WENDOVER DS	35.1	16.2	16.6	16.9	17.2	17.4	17.7	18.0	18.2	18.7	19.0	19.4	19.8	20.2	20.7	21.1	21.6	22.0	22.5	22.8	23.3
WILHAVEN DS	41.4	7.4	7.4	7.5	7.6	7.6	7.7	7.8	7.8	7.9	8.0	8.1	8.2	8.3	8.4	8.5	8.7	8.8	8.9	9.0	9.1
WOODROFFE TS	102.4	47.6	52.6	57.4	62.2	66.8	71.5	75.4	79.4	83.5	87.6	91.6	95.1	98.6	102.0	105.3	108.8	112.8	116.8	120.8	120.8

Table A.3: Greater Ottawa region – Summer - High Load Forecast

Name of Station	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Albion TS	86.5	59.9	60.9	61.8	62.7	63.5	64.4	66.4	68.3	70.4	72.5	74.5	76.0	77.5	79.1	80.7	82.3	83.9	85.5	87.1	87.1
ALMONTE TS	96.7	55.6	56.5	57.0	57.8	58.3	64.8	64.6	65.5	70.3	73.6	73.4	74.7	76.1	77.5	78.8	80.3	81.7	83.2	84.7	86.3
ARNPRIOR TS	54.9	39.7	40.0	40.0	41.1	41.7	45.7	48.9	49.2	49.1	49.6	50.0	50.7	51.3	52.0	52.5	53.4	54.0	54.7	55.2	56.0
BILBERRY CREEK TS	85.3	64.4	65.0	65.5	14.3	14.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BRIDLEWOOD MTS	23.5	22.4	22.7	23.0	23.4	23.6	23.9	24.5	25.1	25.8	26.4	27.1	27.6	28.2	28.7	29.3	29.8	30.4	30.9	31.4	31.4
CAMBRIAN MTS	114.0	59.8	64.7	71.3	73.8	76.1	78.3	82.5	86.0	89.6	93.3	97.0	101.1	103.1	102.5	102.7	103.3	104.1	104.8	105.5	106.2
CARLING TS	95.0	91.7	93.4	94.8	109.4	110.5	111.5	131.9	146.0	147.6	149.4	151.8	153.2	154.8	156.6	158.4	160.3	162.5	164.6	166.8	166.8
CENTREPOINT MTS	13.3	13.0	13.2	13.4	13.6	13.8	14.0	14.5	15.1	15.6	16.1	16.6	17.1	17.6	18.1	18.6	19.1	19.5	20.0	20.5	20.5
CLARENCE DS	7.8	2.6	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.1	3.1	3.2	3.2	3.3	3.4	3.4	3.5
CUMBERLAND DS	6.8	6.1	6.2	6.2	6.2	6.3	6.3	6.4	6.5	6.5	6.7	6.7	6.9	7.0	7.1	7.2	7.3	7.5	7.6	7.7	7.8
CYRVILLE MTS	47.5	32.4	35.3	35.4	57.6	49.5	49.0	49.1	48.9	49.3	49.1	49.6	50.0	50.4	50.8	50.5	50.5	51.0	51.4	51.6	52.1
ELLWOOD MTS	47.0	41.9	46.8	48.5	48.9	50.0	49.4	49.2	49.1	49.3	49.1	49.4	49.7	50.0	50.3	50.5	50.9	51.3	51.6	51.9	52.4
FALLOWFIELD MTS	27.2	24.3	29.1	32.2	34.6	33.4	33.3	33.4	33.4	33.2	33.2	33.3	33.5	33.8	33.8	33.8	34.1	34.3	34.7	34.8	35.1
GREELY DS	20.7	22.4	22.6	22.9	23.2	23.4	23.9	24.2	24.5	24.9	25.2	25.9	26.6	27.6	28.4	29.3	30.1	30.6	30.9	30.9	30.9
HAWKESBURY MTS #1	18.0	12.2	12.4	12.5	12.7	12.8	12.9	13.0	13.2	13.3	13.5	13.7	14.0	14.3	14.6	14.8	15.1	15.4	15.7	16.0	16.4
HAWTHORNE TS	144.8	136.6	137.3	137.3	138.2	138.4	139.2	139.7	140.3	141.2	142.0	143.4	143.8	144.7	145.7	146.4	147.4	148.1	148.8	148.6	148.8
HINCHEY TS	85.6	21.9	22.5	32.8	41.4	43.4	47.0	49.2	50.6	51.5	52.2	52.6	52.2	52.3	52.3	52.1	52.2	52.9	53.4	81.7	71.1
HYDRO RD MTS	114.0	-	-	14.2	19.0	24.4	29.8	33.2	36.8	40.4	43.9	47.5	47.9	48.4	48.9	49.3	49.8	49.9	50.1	50.3	50.3
CTS-1	100.0	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8
KANATA MTS	51.5	54.1	54.1	53.7	53.8	53.5	53.5	53.5	53.3	53.4	53.5	53.6	54.0	54.5	54.9	55.2	55.4	55.9	56.3	56.6	57.0
KING EDWARD TS	86.9	79.0	80.8	82.4	84.0	85.5	87.1	90.8	93.4	96.0	98.6	101.0	103.6	106.2	109.0	111.7	114.5	117.7	120.9	124.1	124.1
LIMEBANK MTS	75.0	51.7	60.8	66.3	71.7	72.9	74.8	76.9	78.8	80.4	81.3	82.7	84.5	86.0	87.8	89.3	90.9	91.2	91.7	92.1	92.9
LINCOLN HEIGHTS TS	99.4	46.4	46.8	47.6	48.5	49.2	50.1	51.3	52.6	53.9	55.2	56.4	57.6	58.8	60.0	61.3	62.6	63.9	65.3	66.7	66.7
LISGAR TS	83.4	78.5	80.7	82.7	98.3	100.0	101.9	112.7	112.7	112.7	112.7	113.5	113.5	113.5	113.7	113.9	114.1	115.5	116.9	118.3	118.3
LONGUEUIL TS	123.5	46.3	49.4	51.6	52.5	52.3	52.8	53.3	53.7	65.8	66.2	65.5	70.5	70.2	71.4	72.4	73.5	74.4	75.4	76.3	77.3
MANORDALE MTS	9.6	10.3	10.5	10.6	10.7	10.9	11.0	11.4	11.8	12.2	12.6	13.0	13.3	13.7	14.1	14.6	15.0	15.3	15.7	16.1	16.1
MANOTICK DS	7.7	10.6	10.8	10.9	11.1	11.2	11.4	11.5	11.7	11.9	12.1	12.4	12.6	12.9	13.2	13.5	13.8	14.1	14.4	14.7	15.0
MARCHWOOD MTS	32.3	51.6	52.6	53.2	54.8	56.1	57.4	58.6	59.9	61.4	61.9	61.5	62.0	62.4	62.7	63.0	63.3	63.8	64.2	64.6	65.0

MARIONVILLE DS	13.5	15.5	15.6	15.7	15.9	16.0	16.3	16.4	16.6	16.8	17.0	17.3	17.8	18.2	18.7	19.2	19.7	20.0	20.2	20.1	20.1
Mer Bleue MTS	114.0	0.0	0.0	0.0	67.5	68.7	70.1	72.2	74.5	76.8	79.1	81.4	83.3	85.1	87.1	89.0	90.9	92.6	94.4	96.1	96.1
MERIVALE MTS	32.9	18.5	18.3	18.1	17.9	17.9	18.1	18.1	18.2	18.3	18.4	18.5	18.6	18.7	18.9	19.0	19.2	19.5	19.7	20.0	20.0
MOULTON MTS	32.0	24.4	23.9	23.5	36.8	36.8	36.7	37.0	37.3	37.7	38.0	38.3	38.6	38.9	39.2	39.5	39.9	40.2	40.6	40.9	40.9
CTS-2	14.0	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5
NRC TS	77.4	5.1	5.1	5.0	17.1	16.8	16.5	16.4	16.4	16.3	16.2	16.0	15.8	15.8	15.8	15.8	15.8	15.7	15.7	15.7	15.7
NAVAN DS	13.5	5.1	5.1	5.1	5.1	5.1	5.1	5.2	5.2	5.4	5.4	5.4	5.5	5.7	5.7	5.8	5.9	6.0	6.0	6.1	6.2
NEPEAN EPWORTH MTS	12.9	12.6	12.7	12.8	12.9	13.0	13.1	13.3	13.5	13.7	14.0	14.2	14.4	14.6	14.9	15.1	15.4	15.6	15.9	16.1	16.1
NEPEAN TS	144.1	126.1	127.0	127.0	127.5	127.7	128.1	128.0	127.7	128.1	128.2	128.7	129.8	130.7	131.6	132.3	133.2	134.1	135.0	135.8	136.8
ORLEANS TS	118.2	119.6	125.4	119.9	125.6	128.1	153.8	148.5	151.2	152.6	154.4	156.7	159.7	161.1	163.0	164.8	166.7	168.7	170.4	172.2	174.2
OVERBROOK TS	116.8	89.4	91.9	94.1	96.3	98.4	100.6	103.1	105.7	108.3	110.9	113.6	115.9	118.4	120.9	123.5	126.0	128.8	131.6	134.4	134.4
PIPERVILLE MTS	108.0	0.0	2.4	4.8	7.2	9.5	11.8	12.1	12.5	12.9	13.3	13.7	14.2	14.7	15.2	15.7	16.2	16.6	16.9	17.3	17.3
RICHMOND SOUTH MTS	49.0	21.4	26.3	28.6	31.2	33.3	35.4	40.5	44.2	47.6	51.0	54.0	57.3	56.6	57.5	58.2	58.8	59.1	59.5	59.8	60.2
RIVERDALE TS	110.8	98.6	102.4	105.9	109.4	112.6	116.0	117.8	119.7	121.6	123.5	125.3	127.2	129.3	131.5	133.7	135.9	138.7	141.4	144.2	144.2
ROCKLAND DS	7.8	8.4	8.7	8.9	9.1	11.1	12.1	13.2	14.3	15.4	18.9	19.6	21.2	22.7	24.3	25.8	27.3	28.9	30.4	31.9	33.5
ROCKLAND EAST DS	15.5	15.5	16.2	16.6	17.2	17.7	18.3	18.8	19.3	19.8	20.4	20.9	21.6	22.3	23.0	23.6	24.3	25.0	25.2	25.6	26.0
RUSSELL DS	6.8	4.5	4.5	4.5	4.6	4.6	4.7	4.8	4.8	4.9	4.9	5.1	5.2	5.3	5.5	5.6	5.8	5.9	5.9	5.9	5.9
RUSSELL TS	72.7	74.2	78.9	79.0	79.8	80.4	81.2	81.6	82.2	82.8	83.6	84.2	84.7	85.1	85.6	86.1	96.7	97.5	98.4	99.3	99.3
SLATER TS	158.7	96.6	97.3	98.8	104.4	109.4	114.4	118.0	118.7	119.8	119.4	119.6	120.5	121.1	121.8	122.5	123.0	124.1	124.8	125.6	126.5
SOUTH GLOUCESTER DS	6.8	5.0	5.0	5.1	5.1	5.2	5.3	5.3	5.4	5.4	5.5	5.6	5.8	6.0	6.2	6.3	6.5	6.6	6.7	6.7	6.7
SOUTH MARCH TS	99.2	98.5	104.1	111.0	112.3	111.6	113.8	123.4	121.0	121.6	126.9	126.7	127.9	128.9	130.0	131.0	132.0	133.3	134.3	135.4	136.6
ST. ISIDORE TS	117.8	45.6	48.7	49.2	50.6	51.8	53.1	58.5	62.8	62.2	64.8	64.7	65.5	66.5	67.3	68.0	69.0	69.8	70.7	71.6	72.5
STEWARTVILLE TS	49.5	28.6	29.0	29.1	29.5	29.7	30.0	30.2	30.5	31.0	31.4	31.8	36.4	36.0	36.4	36.9	37.4	37.9	38.4	38.9	39.5
TERRY FOX MTS	91.7	63.6	64.7	65.2	66.1	66.7	67.6	66.9	66.9	66.9	66.9	67.0	66.6	66.4	66.2	65.9	65.9	66.5	67.1	67.5	68.0
UPLANDS MTS	57.6	29.8	35.6	45.2	44.5	45.7	46.0	46.7	47.3	48.0	48.7	49.7	50.7	51.2	52.1	52.8	53.5	53.6	54.0	54.3	54.7
WENDOVER DS	30.4	16.0	16.2	16.4	16.6	16.8	17.0	17.3	17.5	18.1	18.3	18.6	19.0	19.4	20.0	20.3	25.7	24.3	24.7	25.1	25.6
WILHAVEN DS	34.2	7.9	7.9	7.9	8.0	8.0	8.1	8.1	8.2	8.3	8.4	8.9	8.9	9.2	9.3	9.4	9.5	9.6	9.7	9.9	10.0
WOODROFFE TS	97.4	50.2	51.5	52.6	53.7	54.8	55.9	57.1	58.5	59.8	61.2	62.5	63.8	65.2	66.6	68.1	69.6	70.9	72.3	73.7	73.7

Table A.4: Greater Ottawa region – Winter - High Load Forecast

Name of Station	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
ALBION TS	101.7	71.2	78.6	85.7	92.9	99.8	106.8	111.3	115.8	120.5	125.1	129.7	135.1	140.6	145.8	151.0	156.3	161.2	166.0	170.9	170.9
ALMONTE TS	0.0	52.7	53.6	54.4	55.4	56.0	62.6	62.4	63.2	64.2	65.0	66.4	67.7	69.1	70.6	72.0	73.5	75.0	76.5	78.1	79.6
ARNPRIOR TS	59.4	39.6	40.0	40.4	41.6	42.3	42.4	43.0	44.8	44.8	45.3	45.9	46.6	47.3	48.0	48.7	49.4	50.1	50.8	51.6	52.2
BILBERRY CREEK TS	95.5	62.2	67.2	72.1	14.3	14.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BRIDLEWOOD MTS	23.5	20.5	22.6	24.6	26.7	28.6	30.6	32.0	33.4	34.8	36.3	37.7	39.3	40.9	42.5	44.0	45.6	47.1	48.6	50.1	50.1
CAMBRIAN MTS	123.5	56.0	62.5	68.9	85.2	91.2	97.2	101.3	121.8	126.0	130.3	134.6	138.3	142.0	145.6	149.3	153.0	157.7	162.5	167.3	167.3
CARLING TS	124.3	101.9	112.7	123.1	146.7	156.8	186.1	192.2	211.4	218.2	224.9	232.3	239.9	247.8	255.1	262.1	269.8	276.8	283.8	290.8	290.8
CENTREPOINT MTS	13.3	15.0	16.6	18.2	19.8	21.3	22.8	24.1	25.4	26.7	28.0	29.3	30.7	32.0	33.3	34.6	36.0	37.2	38.5	39.7	39.7
CLARENCE DS	10.5	2.3	2.3	2.3	2.4	2.4	2.4	2.5	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9	3.0	3.0	3.1	3.1
CUMBERLAND DS	8.6	5.3	5.3	5.4	5.5	5.5	5.6	5.6	5.7	5.8	5.9	6.0	6.1	6.2	6.3	6.4	6.5	6.6	6.8	6.9	7.0
CYRVILLE MTS	47.5	38.1	42.5	46.9	51.3	55.5	59.8	62.4	65.1	67.9	70.7	73.4	76.4	79.4	82.3	85.2	88.2	90.8	93.5	96.1	96.1
ELLWOOD MTS	47.0	48.3	53.3	58.3	63.2	68.0	72.8	76.7	80.7	84.7	88.6	92.5	96.5	100.4	104.2	107.9	111.8	115.4	119.1	122.7	122.7
FALLOWFIELD MTS	27.2	19.0	22.4	25.7	31.0	34.2	37.4	40.3	43.3	46.2	49.2	52.1	55.9	59.6	63.4	67.0	70.7	73.3	75.8	78.4	78.4
GREELY DS	25.2	27.4	27.6	27.9	28.4	28.6	29.3	29.5	29.9	30.3	30.8	31.7	32.7	33.7	34.7	35.6	36.6	37.0	37.3	37.1	37.1
HAWKESBURY MTS #1	18.0	13.2	13.7	14.2	14.7	15.1	15.5	15.9	16.4	16.9	17.4	17.7	18.1	18.6	19.1	19.5	20.0	20.5	21.0	21.5	22.1
HAWTHORNE TS	171.6	150.0	158.2	166.2	174.2	182.0	190.0	197.2	204.5	211.9	219.3	226.8	234.9	243.1	250.9	258.3	266.4	272.6	278.5	285.9	285.9
HINCHEY TS	95.0	67.8	76.7	85.3	93.9	102.3	110.7	116.2	121.9	127.6	133.3	138.9	145.0	151.1	157.0	162.7	168.7	174.0	179.2	184.5	184.5
HYDRO RD MTS	123.5	-	-	10.0	14.3	18.5	22.8	25.7	28.6	31.4	34.3	37.2	38.0	38.9	39.8	40.7	41.6	41.6	41.6	41.6	41.6
CTS-1	100.0	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8
KANATA MTS	51.5	60.3	63.1	71.2	73.9	76.5	79.1	81.1	83.1	85.2	87.2	89.2	92.0	94.9	97.6	100.2	103.0	105.4	107.9	110.3	110.3
KING EDWARD TS	90.3	108.4	119.5	130.2	141.0	151.4	162.0	172.2	181.3	190.4	199.4	208.3	218.6	228.9	238.8	248.4	258.6	267.8	277.0	286.2	286.2
LIMEBANK MTS	75.0	71.7	79.3	86.7	94.2	101.3	108.4	112.5	116.7	121.0	125.3	129.6	134.1	138.6	142.9	147.2	151.7	156.0	160.3	164.6	164.6
LINCOLN HEIGHTS TS	113.1	64.5	70.9	77.3	83.6	89.7	95.8	99.9	104.0	108.2	112.4	116.5	121.7	127.0	132.1	137.1	142.3	146.6	150.9	155.2	155.2
LISGAR TS	105.1	90.7	98.9	106.8	128.4	136.0	143.8	160.2	165.8	171.4	177.0	183.5	189.8	196.3	202.4	208.2	214.5	219.8	225.1	230.4	230.4
LONGUEUIL TS	133.0	51.2	54.8	57.4	58.6	58.5	59.2	59.9	60.6	61.3	62.2	63.2	64.2	65.4	66.5	67.7	68.9	70.1	71.2	72.5	73.7
MANORDALE MTS	9.6	11.6	12.8	13.9	15.1	16.2	17.3	18.3	19.2	20.1	21.1	22.0	23.0	24.1	25.1	26.0	27.0	28.0	29.0	29.9	29.9
MANOTICK DS	10.4	12.0	12.3	12.5	12.8	13.0	13.4	13.7	14.1	14.5	14.9	15.7	16.5	17.4	18.4	19.4	20.5	21.2	21.7	21.6	21.6
MARCHWOOD MTS	32.3	37.5	41.0	44.5	47.9	51.2	54.6	56.9	59.2	61.6	64.0	66.3	68.8	71.3	73.8	76.1	78.6	80.8	83.1	85.3	85.3

MARIONVILLE DS	13.5	18.4	18.6	18.9	19.2	19.7	19.9	20.5	20.8	21.2	21.7	22.2	23.2	24.4	25.7	27.0	28.4	30.1	30.9	31.4	31.4
Mer Bleue MTS	123.5	0.0	0.0	0.0	92.5	100.1	107.7	112.6	117.5	122.6	127.7	132.7	138.2	143.8	149.3	154.8	160.3	165.5	170.7	175.9	175.9
MERIVALE MTS	37.3	19.5	21.6	23.7	25.8	27.8	29.9	31.3	32.7	34.1	35.5	36.9	38.5	40.2	41.8	43.3	44.9	46.3	47.7	49.2	49.2
MOULTON MTS	32.0	22.0	24.1	26.2	42.0	43.9	45.9	47.3	48.7	50.2	51.7	53.1	54.7	56.2	57.7	59.2	60.8	62.1	63.4	64.8	64.8
CTS-2	14.0	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6
NRC TS	87.7	6.1	6.0	5.9	20.3	20.0	19.7	19.6	19.6	19.5	19.4	19.2	19.0	18.9	18.9	18.9	18.9	18.9	18.8	18.8	18.8
NAVAN DS	13.5	4.3	4.4	4.4	4.4	4.5	4.5	4.5	4.6	4.6	4.6	4.7	4.8	4.8	4.9	5.0	5.1	5.1	5.2	5.3	5.3
NEPEAN EPWORTH MTS	12.9	12.3	13.5	14.6	15.8	16.9	18.0	18.9	19.8	20.8	21.7	22.6	23.6	24.5	25.5	26.4	27.3	28.2	29.1	29.9	29.9
NEPEAN TS	160.7	138.9	152.2	165.2	178.1	190.8	203.6	212.1	220.6	229.3	237.8	246.1	255.9	265.8	275.1	284.0	293.7	303.5	313.4	323.2	323.2
ORLEANS TS	134.5	82.9	90.3	96.7	72.2	74.7	101.0	94.7	97.6	98.6	100.4	102.5	104.6	105.4	106.6	107.7	109.0	110.2	111.3	112.6	113.6
OVERBROOK TS	135.6	105.5	116.3	126.8	137.3	147.6	157.9	166.2	174.6	183.0	191.4	199.6	208.4	217.4	225.9	234.1	242.9	250.7	258.6	266.4	266.4
PIPERVILLE MTS	117.0	0.0	3.7	7.3	10.9	14.4	17.9	19.0	20.1	21.2	22.3	23.5	25.1	26.6	28.2	29.8	31.4	32.5	33.7	34.8	34.8
RICHMOND South MTS	49.0	21.6	23.7	47.0	55.3	57.0	58.9	60.4	61.9	63.4	72.2	73.8	75.4	77.1	78.7	80.3	81.9	83.5	85.1	86.7	86.7
RIVERDALE TS	117.0	112.3	123.7	134.9	146.0	156.8	167.7	175.5	183.4	191.4	199.2	207.0	215.3	223.8	231.9	239.7	248.0	255.7	263.2	270.8	270.8
ROCKLAND DS	10.5	7.0	7.3	7.5	7.8	9.8	10.8	12.0	13.1	14.2	17.8	18.6	20.1	21.7	23.3	24.8	26.4	28.0	29.5	31.1	32.6
ROCKLAND EAST DS	20.9	12.6	13.3	13.9	14.5	15.0	15.6	16.1	16.6	17.1	17.7	18.3	18.9	19.6	20.2	20.9	21.5	22.2	22.3	22.7	23.0
RUSSELL DS	8.6	5.3	5.4	5.5	5.6	5.7	5.8	6.0	6.1	6.2	6.4	6.5	6.8	7.2	7.6	8.1	8.5	9.0	9.2	9.4	9.4
RUSSELL TS	79.9	79.2	90.5	99.5	106.3	112.9	119.6	124.2	128.8	133.5	138.1	142.6	147.7	152.9	157.8	162.4	166.9	171.4	175.8	180.3	180.3
SLATER TS	163.0	100.4	105.7	110.9	116.0	121.0	126.0	130.5	134.9	139.5	143.9	148.3	153.8	159.4	164.6	169.6	175.1	179.4	183.7	187.9	187.9
SOUTH GLOUCESTER DS	8.6	5.9	6.0	6.1	6.2	6.4	6.5	6.7	6.8	6.9	7.1	7.3	7.6	8.1	8.6	9.1	9.6	10.1	10.4	10.6	12.5
SOUTH MARCH TS		100.1	110.2	114.8	123.5	125.9	136.5	148.7	149.3	152.6	162.2	164.4	170.9	175.5	181.8	186.4	192.7	196.1	201.2	205.6	210.6
ST. ISIDORE TS	124.5	48.2	51.7	52.7	54.3	55.6	57.1	58.5	60.2	61.0	63.7	63.8	64.7	65.7	66.7	67.6	68.8	69.8	70.7	68.6	70.6
STEWARTVILLE TS	56.7	28.0	28.4	28.7	29.2	29.4	29.7	30.1	30.4	30.8	31.2	31.7	36.1	35.3	35.8	36.4	36.9	37.5	38.0	38.5	39.0
TERRY FOX MTS	105.8	62.5	69.4	76.0	82.7	89.1	95.5	100.8	106.2	111.7	117.1	122.6	127.7	132.9	137.9	142.9	148.0	152.8	157.6	162.4	162.4
UPLANDS MTS	65.8	31.7	35.0	38.3	41.5	44.7	47.8	50.1	52.5	54.8	57.2	59.5	62.0	64.6	67.1	69.5	72.0	74.3	76.6	78.9	78.9
WENDOVER DS	35.1	16.4	16.7	17.0	17.3	17.5	17.8	18.1	18.4	19.0	19.2	19.6	20.0	20.5	20.9	21.3	21.8	22.3	22.7	23.0	23.5
WILHAVEN DS	41.4	7.4	7.5	7.6	7.6	7.7	7.7	7.8	7.9	7.9	8.0	8.1	8.2	8.4	8.5	8.6	8.7	8.9	9.0	9.1	9.2
WOODROFFE TS	102.4	57.9	64.1	70.2	76.2	82.0	87.9	92.2	96.5	100.9	105.3	109.6	113.7	117.8	121.7	125.5	129.6	133.8	138.1	142.3	142.3

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Albion TS	230	M30A, M31A
2	Almonte TS	230	E34M, T33E
3	Arnprior TS	115	W6CS, C7BM
4	Bilberry Creek TS**	115	A2, H9A
5	Bridlewood MTS	115	S7M
6	Cambrian MTS	230/115	S7M, E34M
7	Carling TS	115	M4G, M5G
8	Centrepoint MTS	115	C7BM
9	Clarence DS	115	79M1
10	CTS -1	230	B5D, D5A
11	CTS-2	115	A8M
12	Cumberland DS	115	H9A
13	Cyrville MTS	115	A2, A4K
14	Ellwood MTS	230	M30A, M31A
15	Fallowfield MTS	115	S7M
16	Greely DS	115	M1R
17	Hawkesbury MTS #1	115	79M1
18	Hawthorne TS*	230/115	A6R M30A A8M H9A D5A A42T M31A A3RM A4K A2 A41T A5RK L24A
19	Hinchey TS	115	F10MV, V12M
20	Kanata MTS	230	C3S, M32S
21	King Edward TS	115	A4K, A5RK
22	Limebank MTS	115	S7M
23	Lincoln Heights TS	115	C7BM, F10MV
24	Lisgar TS	115	M4G, M5G
25	Longueuil TS	230	B5D, D5A
26	Manotick DS	115	S7M
27	Marchwood MTS	115	S7M, W6CS
28	Marionville DS	115	L2M

29	Merivale MTS	115	-
30	Merivale TS*	230	M30A S7M E34M A8M M5G M32S M1R M31A F10MV C7BM A3RM M4G V12M L2M
31	Moulton MTS	115	A4K
32	National Research Council TS	115	A2
33	Navan DS	115	H9A
34	Nepean Epworth MTS	115	M5G M4G
35	Nepean TS	230	M32S
36	Orleans TS	230/115	D5A, H9A
37	Overbrook TS	115	A5RK, A6R
38	Richmond South MTS	115	S7M
39	Riverdale TS	115	A3RM, A5RK, A6R
40	Rockland DS	115	79M1
41	Rockland East DS	115	79M1
42	Russell DS	115	L2M, M1R
43	Russell TS	115	A5RK, A6R
44	Slater TS	115	A3RM, A5RK, M4G
45	South Gloucester DS	115	M1R
46	South March TS	230	C3S, M32S
47	St. Isidore TS	230	B5D, D5A
48	Stewartville TS	115	W3B, W6CS
49	Terry Fox MTS	230	E34M
50	Uplands MTS	115	A8M
51	Wendover DS	115	79M1
52	Wilhaven DS	115	H9A
53	Woodroffe TS	115	C7BM, F10MV

Appendix C: Lists of Transmission Circuits

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Hawthorne TS – Merivale TS	M30A, M31A	230
2	Hawthorne TS – St Isidore TS	D5A	230
3	Merivale TS – Almonte TS	E34M	230
4	Merivale TS – South March TS	M32S	230
5	South March SS – Chats Falls SS	C3S	230
6	Hawthorne TS – Bilberry Creek TS	A2	115
7	Hawthorne TS - Merivale TS	A3RM, A8M	115
8	Hawthorne TS – Overbrook TS	A4K, A5RK	115
9	Hawthorne TS – Riverdale TS	A6R	115
10	Hawthorne TS – Hawkesbury MTS	H9A/79M1	115
11	Merivale TS – Chats Falls TS	C7BM	115
12	Merivale TS – Hinchey TS	F10MV, V12M	115
13	Merivale TS – Lisgar TS	M4G, M5G	115
14	Merivale TS – South March SS	S7M	115
15	Stewartville TS – South March SS	W6CS	115
16	Stewartville TS – Barrett Chute TS	W3B	115
17	Hawthorne TS – Merivale TS	M30A, M31A	230
18	Hawthorne TS – St Isidore TS	D5A	230
19	Merivale TS – Almonte TS	E34M	230
20	Merivale TS – South March TS	M32S	230
21	South March SS – Chats Falls SS	C3S	230
22	Hawthorne TS – Bilberry Creek TS	A2	115
23	Hawthorne TS - Merivale TS	A3RM, A8M	115
24	Hawthorne TS – Overbrook TS	A4K, A5RK	115
25	Hawthorne TS – Riverdale TS	A6R	115
26	Hawthorne TS – Hawkesbury MTS	H9A/79M1	115

27	Merivale TS – Chats Falls TS	C7BM	115
28	Merivale TS – Hinchey TS	F10MV, V12M	115
29	Merivale TS – Lisgar TS	M4G, M5G	115
30	Merivale TS – South March SS	S7M	115
31	Stewartville TS – South March SS	W6CS	115
32	Stewartville TS – Barrett Chute TS	W3B	115

Appendix D: List of LDC's

Sr. no.	Name of LDC
1	Hydro One
2	Hydro Ottawa Ltd.
3	Hydro 2000 Inc.
4	Hydro Hawkesbury
5	Ottawa River Power Corporation
6	Renfrew Hydro Inc.

Appendix E: List of Municipalities in the region

Sr. no.	Name of Municipality
1	City of Ottawa
2	City of Clarence-Rockland
3	Town of Arnprior
4	Town of Carleton Place
5	Municipality of Mississippi Mills
6	Municipality of The Nation
7	Township of East Hawkesbury
8	Township of Champlain
9	Township of Alfred and Plantagenet
10	Township of Russell
11	Township of Beckwith
12	Township of Drummond/North Elmsley
13	Township of Tay Valley
14	Township of North Frontenac
15	Township of Lanark Highlands
16	Township of McNab/Braeside
17	Township of Greater Madawaska

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BESS	Battery Energy Storage System
BPS	Bulk Power System
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
eDSM	Electricity Demand Side Management
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	KiloVolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.

NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
RAS	Remedial Action Scheme
SS	Switching Station
TS	Transformer Station
TAO	Transmission Asset Owner
TWG	Technical Working Group