

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

June 12, 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-2026-0155 – Hydro One Networks Inc. Leave to Construct – Durham Kawartha Power Line Project – 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 line facilities (“**DKPL Project**” or the “**Project**”) located in Eastern Ontario between the County of Peterborough and the Municipality of Clarington.

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 OEB’s Regulatory Electronic Submission System.

Sincerely,



Pasquale Catalano

1

EXHIBIT LIST

Exhibit	Tab	Schedule	Attachment	Contents
A				
	1	1		Exhibit List
	1	2		Application Table of Concordance
	1	3		List of Acronyms and Abbreviations
B				
	1	1		Application
	2	1		Project Overview Documents
	2	1	1	General Area Map
	2	1	2	Schematic Diagram of Proposed Line Facilities
	2	1	3	Schematic Diagram of Proposed Dobbin TS Configuration
	2	1	4	Schematic Diagram of Proposed Clarington TS Configuration
	3	1		Evidence In Support of Need
	3	1	1	Order-in-Council
	3	1	2	Deputy Minister of Energy Letter to OEB
	3	1	3	Order-in-Council – Priority Project
	3	1	4	OEB Decision Order re: Transmission Licence Amendment
	3	1	5	Hydro One's Transmission Licence – as amended
	3	1	6	IESO Supplemental Evidence to Support the Need for the Project
	4	1		Project Categorization and Classification
	5	1		Cost Benefit Analysis and Options
	6	1		Quantitative and Qualitative Benefits of the Project
	7	1		Apportioning Project Costs and Risks
	8	1		Connection Projects Requiring Network Reinforcement
	9	1		Transmission Rate Impact Assessment
	10	1		Revenue Requirement Information and Deferral Account Requests
	11	1		Project Schedule

Exhibit	Tab	Schedule	Attachment	Contents
C				
	1	1		Descriptions of the Physical Design
D				
	1	1		Operational Details
E				
	1	1		Land Matters
	1	1	1	Detailed Route Map
	1	1	2	List of Properties and Permits Associated with the Project Route
	1	1	3	Early Access Agreement
	1	1	4	Option to Purchase a Limited Interest – Easement
	1	1	5	Compensation and Incentive Agreement – Easement
	1	1	6	Option to Purchase – Fee Simple
	1	1	7	Compensation and Incentive Agreement – Fee Simple
	1	1	8	Agreement for Temporary Rights
	1	1	9	Off Corridor Access
	1	1	10	Crop Land Out of Production Agreement
	1	1	11	Damage Claim Agreement/Waiver
F				
	1	1		System Impact Assessment
	1	1	1	Final IESO System Impact Assessment
G				
	1	1		Customer Impact Assessment
	1	1	1	Final Customer Impact Assessment
H				
	1	1		Regional and Bulk Planning
	1	1	1	IESO Bulk Report: Gatineau Corridor End-of-Life Study (December 2022)
	1	1	2	Peterborough to Kingston RIP (May 2022)
	1	1	3	Peterborough to Kingston IRRP (November 2021)

1

APPLICATION TABLE OF CONCORDANCE

Exhibit	Content	FR Section	Hydro One S.92 Application Section
A	The Index	4.3.1	A-01-01 – Exhibit List
			A-01-02 – Application Table of Concordance
B	The Application	4.3.2	
	Administrative Matters	4.3.2.1	B-01-01 – Application
	Project Overview	4.3.2.2	B-02-01 – Project Overview Documents C-01-01 – Descriptions of the Physical Design
	Evidence in Support of Need for the Project	4.3.2.3	B-03-01 – Evidence in Support of Need
	Project Categorization	4.3.2.4	B-04-01 – Project Categorization and Classification
	Analysis of Alternatives	4.3.2.5	B-05-01 – Cost Benefit Analysis and Options B-06-01 – Quantitative and Qualitative Benefits of the Project H-01-01 – Regional and Bulk Planning
	Project Costs	4.3.2.6	B-07-01 – Apportioning Project Costs and Risks B-09-01 – Transmission Rate Impact Assessment
	Risks	4.3.2.7	B-07-01 – Apportioning Project Costs and Risks
	Comparable Projects	4.3.2.8	B-07-01 – Apportioning Project Costs and Risks
	Connection Projects that Also Address a Network Need	4.3.2.9	B-08-01 – Connection Projects Requiring Network Reinforcement
	Connection Projects Requiring Network Reinforcement	4.3.2.10	B-08-01 – Connection Projects Requiring Network Reinforcement
	Transmission Rate Impact Assessment	4.3.2.11	B-09-01 – Transmission Rate Impact Assessment
	Establishment of Deferral Accounts	4.3.2.12	B-10-01 – Revenue Requirement Information and Deferral Account Requests
	Capital Contribution Period	4.3.2.13	B-09-01 – Transmission Rate Impact Assessment
	Project Schedule	4.3.2.14	B-11-01 – Project Schedule

Exhibit	Content	FR Section	Hydro One S.92 Application Section
C	Project Details	4.3.3	
	The Route	4.3.3.1	B-02-01 – Project Overview Documents
	Description of the Physical Design	4.3.3.2	C-01-01 – Descriptions of the Physical Design
	Maps	4.3.3.3	E-01-01 – Land Matters
D	Design Specification and Operational Data	4.3.4	
	Operational Details	4.3.4.1	D-01-01 – Operational Details
E	Land Matters	4.3.5	
	Description of Land Rights Required	4.3.5.1	E-01-01 – Land Matters
	Land Acquisition Process	4.3.5.2	E-01-01 – Land Matters
	Land-related Forms	4.3.5.3	E-01-01 – Land Matters
	Early Access to Land	4.3.5.4	E-01-01 – Land Matters
F	System Impact Assessment	4.3.6	F-01-01 – System Impact Assessment
G	Customer Impact Assessment	4.3.7	G-01-01 – Customer Impact Assessment
H	Regional and Bulk Planning	4.3.8	
	Integrated Regional Resource Plan	4.3.8.1	H-01-01 – Regional and Bulk Planning
	Regional Infrastructure Plan	4.3.8.2	H-01-01 – Regional and Bulk Planning
	Bulk System Plan	4.3.8.3	H-01-01 – Regional and Bulk Planning

1

LIST OF ACRONYMS AND ABBREVIATIONS

<u>Acronym or Abbreviation</u>	<u>Acronym or Abbreviation Expansion</u>
A	Amperes
AACE	Association for the Advancement of Cost Engineering
ACSR	Aluminium-Conductor Steel-Reinforced cable
ACSR/TW	Aluminium-Conductor Steel-Reinforced, trapezoidal shaped cable
AFUDC	Allowance for Funds Used During Construction
ATP	Affiliate Transmission Projects
AW	American Wire gauge
C	Celsius
CIA	Customer Impact Assessment
Class EA	Class Environmental Assessment
CSA	Canadian Standards Association
CxL	Chatham by Lakeshore Transmission Line
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DKPL	Durham Kawartha Power Line
EA	Environmental Assessment
ECI	Early Contractor Involvement
ECI-EPC	Refers to an ECI delivery model that engages the services of an external OE and the services of EPC contractors.
EPC	Engineering, Procurement and Construction
ESR	Environmental Study Report
EWT	East-West Tie
Hydro One	Hydro One Networks Inc. (HONI)
IEP	Integrated Energy Plan
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
ISOC	Integrated System Operating Center
JCT	Junction
kcmil	Kilo-circular mils (<i>unit of measure of the area of a wire with a circular cross section</i>)
km	Kilometer
kV	Kilovolt

<u>Acronym or Abbreviation</u>	<u>Acronym or Abbreviation Expansion</u>
kW	Kilowatt
LACP	Land Acquisition Compensation Principles
m	Meter
MECP	Ministry of the Environment, Conservation and Parks
MTS	Municipal Transformer Station
MW	Megawatt
MWHR / MWH	Megawatt-hour
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NPV	Net Present Value
OE	Owners Engineer
OEB	Ontario Energy Board (the Board)
OIC	Order in Council
OMA	Operations, Maintenance and Administrative costs
OPGW	Optical Ground Wire
PCT	Protection, Control, and Telecommunications
PV	Present Value
RFP	Request for Proposal
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
TSP	Transmission System Plan
UTR	Uniform Transmission Rates
XLPE	Cross-linked polyethylene cable

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 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.

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 of, among other things, 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 230 kV double-circuit transmission line from Dobbin TS to Clarington TS in Eastern Ontario. The approximate length of the transmission line is 55 km.
3. The Application is supported by written evidence which includes details of the Applicant's proposal for the construction of the proposed Project. The written evidence is prefiled and may be amended from time to time prior to the OEB's final decision on this Application.

- 1 4. Acronyms and abbreviations are used throughout the prefilled evidence and those
2 acronyms and abbreviations are defined at **Exhibit A, Tab 1, Schedule 3**.
3
- 4 5. In accordance with Order in Council No. 1532/2023 and Minister's Directive issued
5 October 19, 2023 ("**Directive**"), the Minister of Energy directed Hydro One to develop
6 and seek all necessary approvals for a new 230 kV double-circuit transmission line,
7 including associated expansions or upgrades required at the terminal stations.
8 Further, in accordance with section 96.1 of the Act, and Order in Council No.
9 1531/2023 that was also issued on October 19, 2023, the Lieutenant Governor in
10 Council declared the Project as a priority project. Copies of the Orders in Council and
11 correspondence from the Minister of Energy to the OEB (dated October 23, 2023) to
12 amend Hydro One's transmission licence in accordance with the Directive, are found
13 at **Exhibit B, Tab 3, Schedule 1, Attachments 1 to 3**.
14
- 15 6. The Project is required to increase the overall transfer capability of the bulk
16 transmission system to ensure sufficient supply capacity to the Peterborough to
17 Quinte West region and surrounding area, as recommended by the IESO in its report
18 titled the "*Gatineau Corridor End-of-Life Study*". The IESO's report is provided as
19 **Attachment 1** in **Exhibit H, Tab 1, Schedule 1**. The IESO further reaffirmed the need
20 for the Project in their supplemental evidence provided for the purposes of this
21 Application in **Attachment 6** of **Exhibit B, Tab 3, Schedule 1**. Given the above, the
22 Project has been identified as a non-discretionary development project in **Exhibit B,**
23 **Tab 4, Schedule 1**.
24
- 25 7. The Project is subject to the applicable Class EA process in accordance with the
26 *Ontario Environmental Assessment Act*. On January 30, 2026, Hydro One filed the
27 Final ESR¹ and Statement of Completion with the MECP.

¹ [Hydro One's Durham Kawartha Power Line Class EA Final ESR](#) (January 30, 2026).

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

4
5 9. Hydro One is committed to working with First Nations in a spirit of cooperation and
6 shared responsibility. Hydro One acknowledges that Indigenous governments and
7 communities have unique historic and cultural relationships with their land and a
8 unique knowledge of the natural environment. Forging meaningful relationships with
9 Indigenous governments and communities based upon trust, confidence, and
10 accountability is vital to advancing reconciliation and achieving Hydro One's
11 corporate objectives. Hydro One has been engaging with Indigenous governments
12 and communities since early in the development process and will continue that
13 engagement and involvement in project decisions throughout the life cycle of the
14 Project. Additionally, Hydro One has, and will continue to engage in economic
15 participation negotiations with impacted Indigenous communities throughout the
16 lifecycle of the Project, including through employment, training, contracting and equity
17 participation in the Project.

18
19 10. To advance action on reconciliation, impacted First Nations will have the opportunity
20 to invest in a 50 per cent equity stake in the transmission line component of the Project
21 through Hydro One's First Nations equity partnership model. Hydro One expects that
22 after completion of the Project, ownership of the applied-for transmission line facilities
23 will be transferred and owned by a limited partnership that will include ownership
24 interests held by the impacted First Nations.

25
26 11. As of the date of this Application, the limited partnership has not yet been finalized.
27 As negotiations are ongoing, Hydro One is not able to provide commercial details.
28 However, those details will be provided to the OEB once the limited partnership is
29 formed and through subsequent transmission licence and asset transfer applications
30 made to the OEB. In the circumstances, Hydro One proposes that the OEB-approved

ATP regulatory account² include the costs associated with the transmission line facilities instead of forming part of Hydro One's rate base. For reference, further information on the ATP regulatory account is provided at **Exhibit B, Tab 10, Schedule 1**. Hydro One is not anticipating that the limited partnership will impact the Project cost estimates provided at **Exhibit B, Tab 7, Schedule 1**.

12. The forecast total capital cost of the Project transmission facilities is \$428.2 million³. Details pertaining to these costs are provided at **Exhibit B, Tab 7, Schedule 1**.

13. The expected rate impact associated with the Project (using 2026 OEB-approved uniform transmission rates as filed in **Exhibit B, Tab 9, Schedule 1**) is a \$0.15/month increase on a typical residential customer's bill under RPP.

14. The 230 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**.

15. The IESO has completed a Final SIA. The 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 Final SIA is provided as **Exhibit F, Tab 1, Schedule 1, Attachment 1**.

16. Hydro One has completed a Final CIA in accordance with Hydro One's connection procedures. A copy of the Final CIA is provided as **Exhibit G, Tab 1, Schedule 1, Attachment 1**. 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.

² EB-2021-0169, OEB Decision and Order (October 7, 2021).

³ There will be an additional \$5.1M of OMA removal costs associated with constructing the Project.

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

5
6 18. New permanent land rights on properties between Dobbin TS and Clarington TS will
7 be required to accommodate the proposed 230 kV transmission facilities. The Project
8 will require Hydro One to acquire land rights from 183 directly impacted properties.
9 Temporary rights for construction purposes will also be required at specific locations
10 along the transmission corridor. These rights will be negotiated and acquired as and
11 when needed. Further information regarding the real estate needs to complete the
12 Project is provided in **Exhibit E, Tab 1, Schedule 1.**

13
14 19. This Application is also seeking approval of the forms of the agreement offered or to
15 be offered to affected landowners, pursuant to section 97 of the Act. These
16 agreements are substantively consistent with the forms of agreement previously
17 approved in prior Hydro One leave to construct proceedings. Any agreements that
18 have been altered from their last approval have all been explicitly identified in the
19 Application. The forms of the applied-for agreements are found as attachments to
20 **Exhibit E, Tab 1, Schedule 1.**

21
22 20. Based on the foregoing, and the information provided in the prefiled evidence, Hydro
23 One submits that the Project is in the public interest.

24
25 21. The relief requested herein is required to increase the overall transfer capability of
26 the bulk transmission system to ensure sufficient supply capacity to the Peterborough
27 to Quinte West region and surrounding area. The Project will also provide flexibility
28 and resiliency in meeting future changes in demand and mitigate upstream thermal
29 constraints limiting flows into the Ottawa region. These outcomes are consistent with
30 the IESO's recommendations as set out in its bulk system planning report.

Furthermore, future assessments of the bulk and regional system requirements for Eastern Ontario are predicated on the completion of the Project.

22. The Project has been declared a priority project by the provincial government for purposes of section 96.1 of the Act. Accordingly Hydro One is undertaking development and seeking approvals for the Project as a condition of Hydro One's transmission licence consistent with the Minister of Energy's direction and associated Orders in Council.⁴

23. By locating the new transmission line facilities predominately within an existing transmission corridor, the Project reduces its land use footprint and minimizes impacts on both natural and socio-economic environments.

24. Additionally, approval of the Application will provide meaningful opportunity for Indigenous participation. On June 12, 2025, the Government of Ontario released *Energy for Generations*, an IEP which provides a 25-year roadmap for powering Ontario's growth and economic development in accordance with the province's Affordable Energy Future Vision.⁵ The IEP highlighted the importance of creating opportunities for meaningful Indigenous participation in energy projects. The Project is a collaboration that supports Indigenous-led economic development. As previously stated, Hydro One expects that after completion of the DKPL Project, ownership of the transmission line facilities will be transferred to a limited partnership owned by Hydro One and either directly, or indirectly, First Nations partners. It is in the public interest to support Indigenous partnerships, as stated in the IEP.

25. Hydro One requests:

- a) An Order or Orders pursuant to section 92 of the Act granting leave to construct the Project;

⁴ As per documentation provided in Exhibit B, Tab 3, Schedule 1.

⁵ [Energy for Generations, Ontario's Integrated Plan](#) (June 12, 2025) – Chapter 8, pp. 129-137.

- 1 b) An approval of the forms of the agreement offered, or to be offered, to affected
2 landowners pursuant to section 97 of the Act; and
3 c) Such other relief as Hydro One may request or as the Board may direct.
4

5 26. Hydro One consents to the conditions outlined in the OEB's standard conditions of
6 approval for electricity transmission leave to construct applications⁶ for this Project.
7 Furthermore, Hydro One consents to the OEB proceeding by way of a written hearing
8 for this proceeding.
9

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

12 **a) The Applicant:**

13 Eryn MacKinnon

14 Regulatory Advisor

15 Hydro One Networks Inc.

16 Mailing Address: 7th Floor, South Tower
17 483 Bay Street
18 Toronto, Ontario M5G 2P5

19 Telephone: (437) 318-3700

20 Electronic access: Regulatory@HydroOne.com
21

22 **b) The Applicant's counsel:**

23 Mr. Evan J. Barz / Mr. Andrew Rintoul

24 Osler, Hoskin & Harcourt LLP

25 Mailing Address: Suite 6200, 1 First Canadian Place
26 100 King Street West, P.O Box 50
27 Toronto, Ontario M5X 1B8

28 Telephone: (416) 862-4209 / (416) 862-5963

29 Electronic access: ebarz@osler.com / arintoul@osler.com

⁶ [Electricity Leave to Construct Issues List](#) (December 16, 2025)

1	c) The Applicant's counsel:	
2	Laura Brazil	
3	Assistant General Counsel	
4	Hydro One Networks Inc.	
5	Mailing Address:	8th Floor, South Tower
6		483 Bay Street
7		Toronto, Ontario M5G 2P5
8	Telephone:	(416) 459-9817
9	Electronic access:	laura.brazil@hydroone.com

PROJECT OVERVIEW DOCUMENTS

Hydro One is seeking approval to construct and operate transmission facilities to meet the requirements set out in Hydro One's Transmission Licence as ordered by the OEB and outlined at **Exhibit B, Tab 3, Schedule 1, Attachment 4**. More specifically, the relief sought in this Application satisfies the direction of the Minister of Energy¹, as amended into Hydro One's Transmission Licence², *to develop and seek approvals for a new 230 kV transmission line from Dobbin TS to either Cherrywood TS or Clarington TS, including associated station facility expansions or upgrades required at the terminal stations*, necessary for the construction of this priority designated project.

As detailed in **Exhibit B, Tab 3, Schedule 1, Attachment 6**, the IESO supports the proposed Project – consisting of a new 230 kV double-circuit transmission line between Dobbin TS and Clarington TS – and confirms that it is necessary to maintain a reliable electricity supply to Eastern Ontario.

The following proposed facilities are subject to approval under Section 92 of the Act:

- Approximately 55 km of new 230 kV double-circuit transmission line (Circuits T40P/T41P) from Dobbin TS to Clarington TS, located predominantly within an existing transmission corridor.
- Terminal station modifications at Clarington TS and Dobbin TS, including upgrades at Dobbin TS to address increased fault levels and to implement necessary circuit reconfigurations, along with protection upgrades at four remote stations to accommodate the new 230 kV double-circuit transmission line.
- Upgrade approximately 8 km of skywire on the existing 230 kV single-circuit transmission line (Circuit X1P) emanating out of Dobbin TS to address increased fault levels from the addition of the new 230 kV double-circuit transmission line.

¹ Exhibit B, Tab 3, Schedule 1, Attachments 1 and 3.

² Exhibit B, Tab 3, Schedule 1, Attachment 5.

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

4
5 The Project is situated along what is known as the Gatineau transmission corridor, which
6 extends from the Durham Region to Peterborough and onto Ottawa. This transmission
7 corridor serves a number of purposes, including facilitating generation, enabling bulk
8 system transfer capability across eastern Ontario, and supplying loads in the
9 Peterborough to Quinte West and Ottawa areas. Reinforcement of the transmission
10 system is required to increase the overall transfer capability of the bulk transmission
11 system in the area and to address the system needs identified by the IESO, including the
12 upstream thermal limitation for the Ottawa area. The Project will meet the supply capacity
13 need in the long-term providing flexibility and resiliency in meeting future changes in
14 demand.

15
16 Further information on the overhead transmission line and the station facilities is provided
17 below.

18 **Overhead Transmission Line**

19
20 There are currently three 230 kV single-circuit transmission lines that connect into Dobbin
21 TS: (i) Circuit P15C from Cherrywood TS in the West; (ii) Circuit X1P from Chenaux TS in
22 the North; and (iii) Circuit C27P from the Ottawa area in the East. With the completion of
23 the Project, there will be a total of five 230 kV transmission circuits connecting into Dobbin
24 TS, which will improve supply capability and maintain a reliable electricity supply to
25 Eastern Ontario.

26
27 The proposed 230 kV double-circuit transmission line from Dobbin TS to Clarington TS
28 will pass through the townships of Selwin, Cavan-Monaghan, and Scugog; the City of
29 Kawartha Lakes; and the Municipality of Clarington. The total route length of the proposed
30 transmission line is approximately 55 km. Approximately 95% of the proposed
31 transmission line will be located within an existing transmission corridor. The remaining

1 5% will be located within a new transmission corridor, including a short underground
2 section of approximately 400 m near Regional Road 3 in Clarington to avoid crossing four
3 existing 230 kV single-circuit transmission lines. In addition, approximately 8 km of skywire
4 on the existing 230 kV single-circuit transmission line (Circuit X1P) emanating out of
5 Dobbin TS will be upgraded to a larger skywire to address increased fault levels from the
6 addition of the proposed transmission line.

7
8 Further details on the physical design for the line and routing are provided in **Exhibit C,**
9 **Tab 1, Schedule 1.** A schematic diagram showing the proposed configuration is provided
10 in **Exhibit B, Tab 2, Schedule 1, Attachment 2.**

11 12 **Dobbin TS Line Terminations and Station Facilities**

13 Dobbin TS is an existing station located in the Township of Selwin. The station will require
14 new and modified structures inside the station to accommodate the termination of the new
15 230 kV double-circuit transmission line. The Project will require reconfiguration of three
16 existing 230 kV transmission lines (Circuits P15C, X1P and C27P) to new positions to
17 create sufficient space to build a new diameter, including three new 230 kV breakers and
18 associated equipment, along with replacement of five existing 230 kV breakers due to
19 increasing fault levels at the station as a result of the addition of the new transmission line.

20
21 The Project will also require modifications and additions to the telecommunication,
22 protection and control, SCADA, and monitoring equipment at Dobbin TS, along with
23 corresponding protection and control modifications at Chat Falls SS, Havelock TS and
24 Merivale TS, in order to protect the new facilities and provide status and control capability
25 to Hydro One's ISOC, as well as status information to the IESO. All new facilities will be
26 built on Hydro One's existing owned property.

27
28 Further details on the physical design for the station are provided in **Section 4.0 of Exhibit**
29 **C, Tab 1, Schedule 1.** A schematic diagram showing the proposed configuration at
30 Dobbin TS is provided in **Exhibit B, Tab 2, Schedule 1, Attachment 3.**

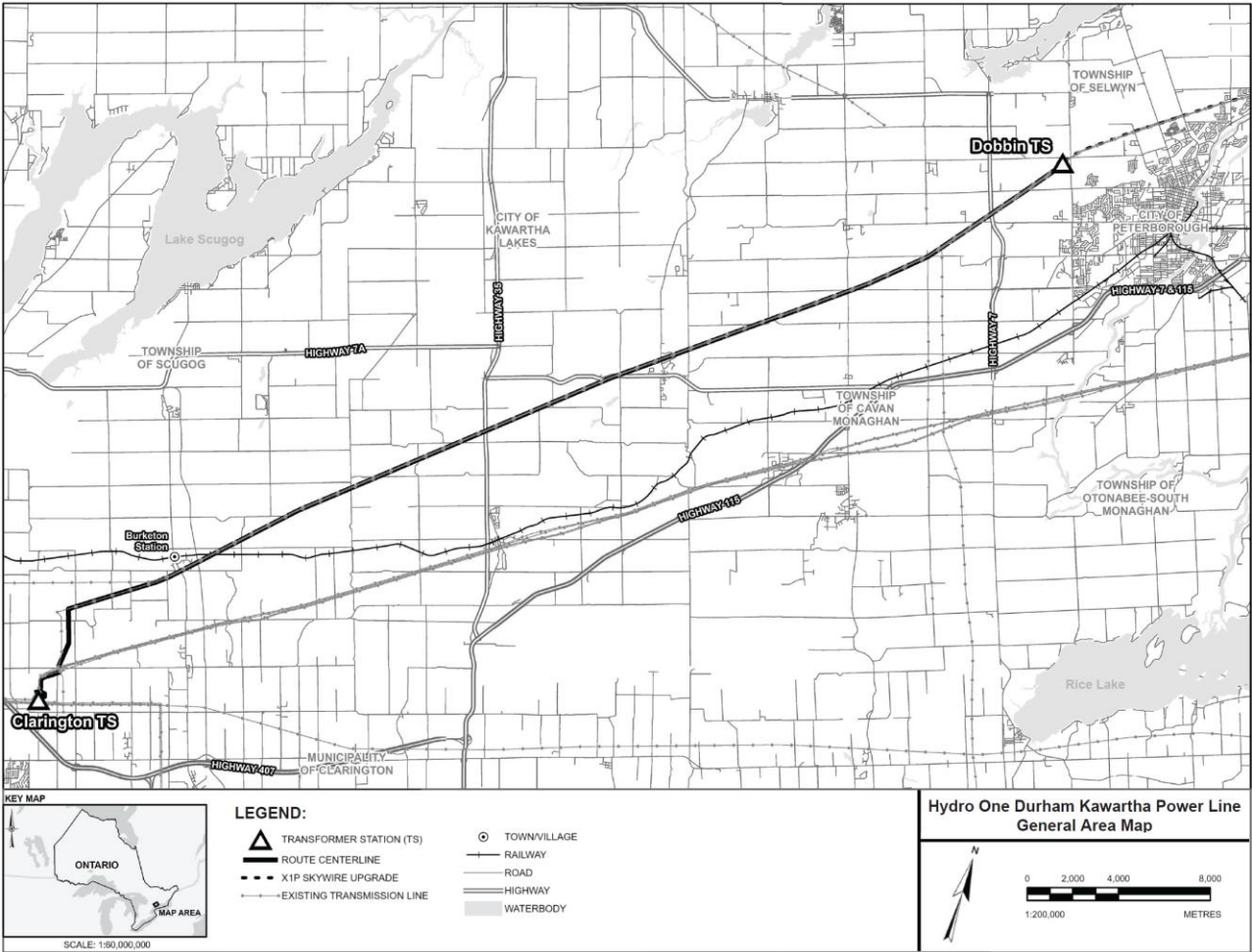
1 **Clarington TS Line Termination and Station Facilities**

2 Clarington TS is an existing station located in the Municipality of Clarington. The station
3 will require new and modified structures inside the station to accommodate the termination
4 of the new 230 kV double-circuit transmission line. The Project will require relocation of
5 an existing capacitor bank to create sufficient space to the build a new diameter, including
6 two new 230 kV breakers and associated equipment for the termination of one of the new
7 230 kV transmission circuits (Circuit T41P). The other new 230 kV transmission circuit
8 (Circuit T40P) will repurpose the existing diameter and termination point of the de-
9 energized section of the 230 kV transmission line (Circuit T28C).

10
11 The Project will also require modifications and additions to the telecommunication,
12 protection and control, SCADA, and monitoring equipment at Clarington TS, along with
13 corresponding protection and control modifications at Cherrywood TS for Circuit T28C, to
14 protect the new facilities and provide status and control capability to Hydro One's ISOC,
15 as well as status information to the IESO. All new facilities will be built on Hydro One's
16 existing owned property.

17
18 Further details on the physical design for the station are provided in **Section 4.0 of Exhibit**
19 **C, Tab 1, Schedule 1**. A schematic diagram showing the proposed configuration at
20 Clarington TS is provided in **Exhibit B, Tab 2, Schedule 1, Attachment 4**.

GENERAL AREA MAP

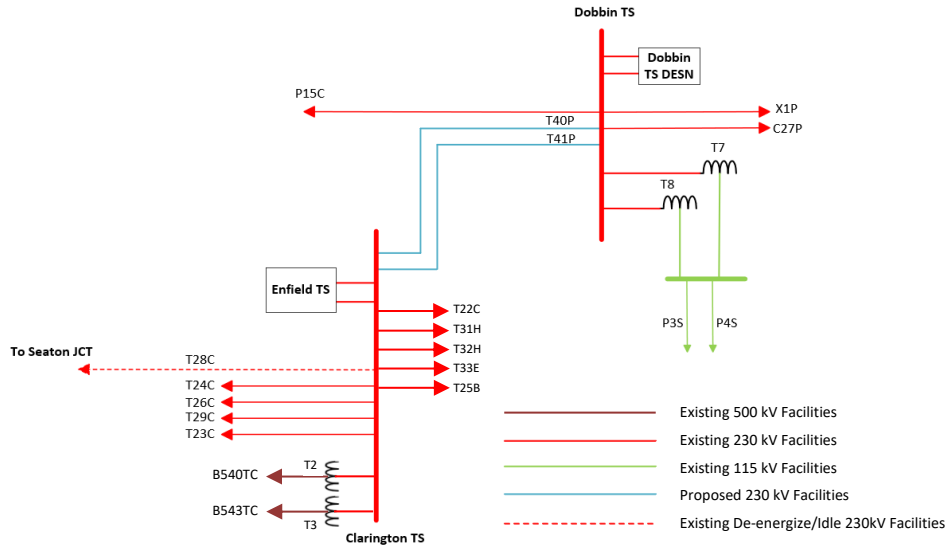


1

PROPOSED FACILITIES:

2

DOBBIN TS TO CLARINGTON TS LINE SCHEMATIC DIAGRAM

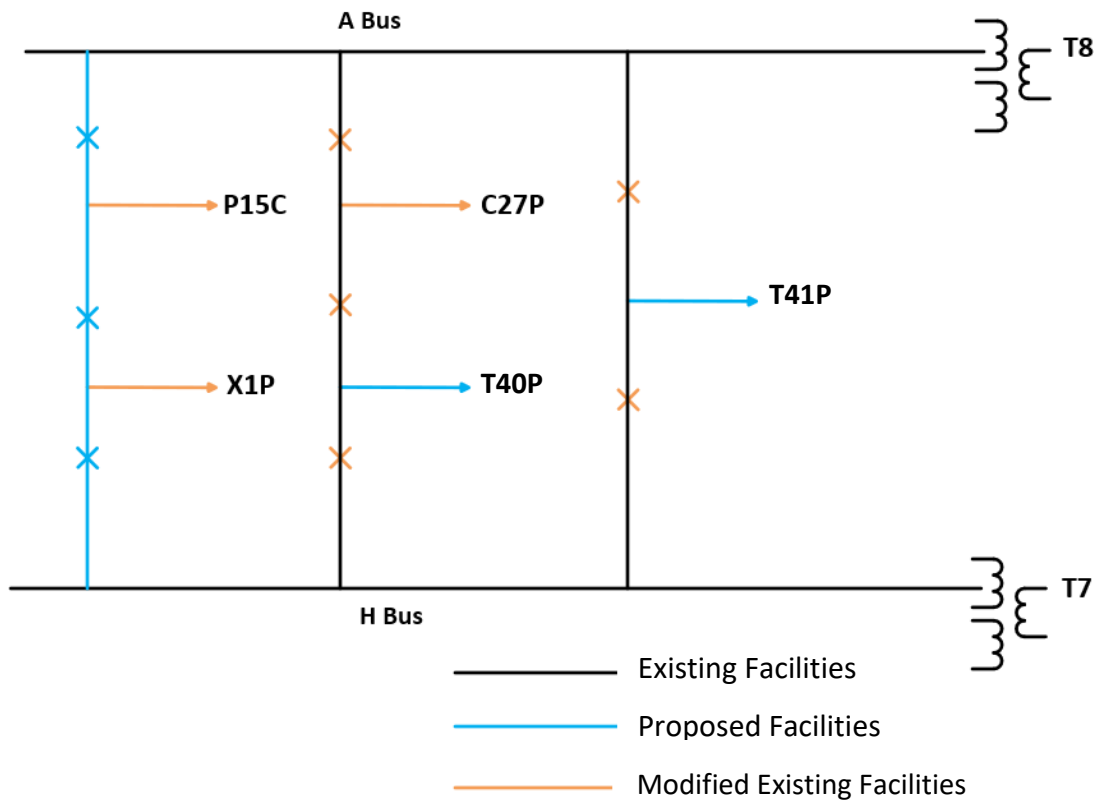


1

PROPOSED FACILITIES:

2

230 KV DOBBIN TS SIMPLIFIED SCHEMATIC DIAGRAM

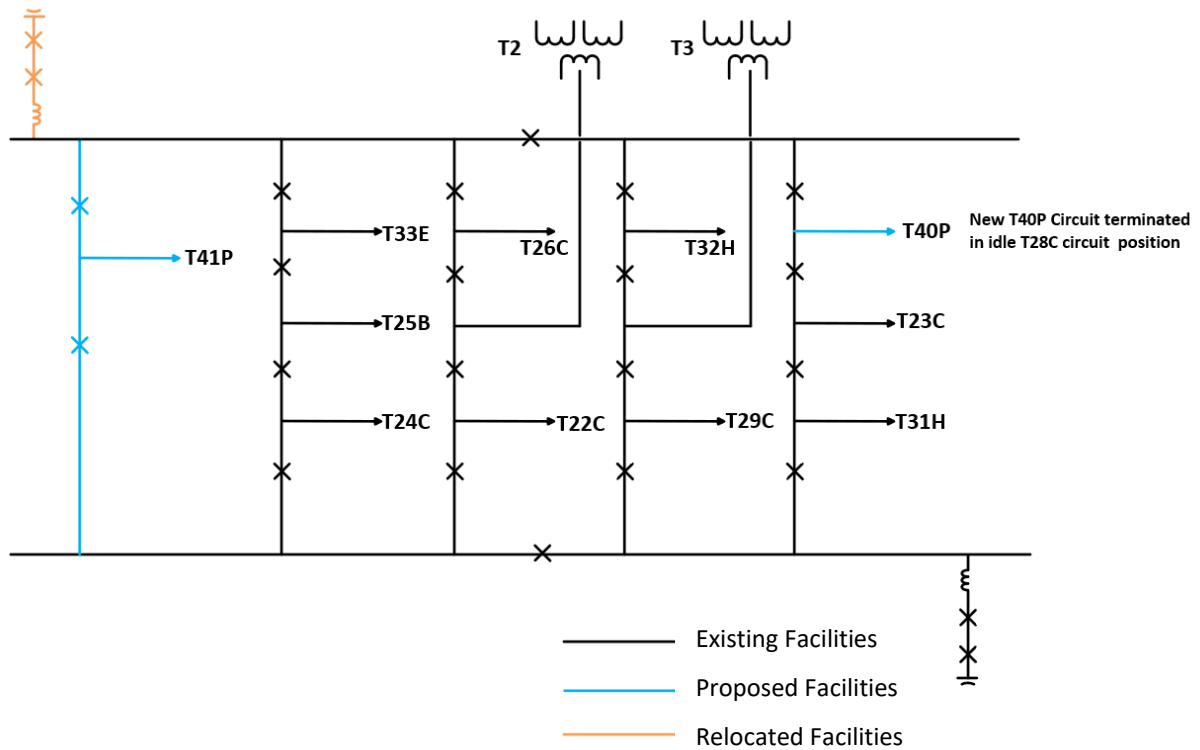


1

PROPOSED FACILITIES:

2

230 KV CLARINGTON TS SIMPLIFIED SCHEMATIC DIAGRAM



EVIDENCE IN SUPPORT OF NEED

In December 2022, the IESO published a bulk system report titled “*Gatineau Corridor End-of-Life Study*”, which is provided as **Attachment 1** in **Exhibit H, Tab 1, Schedule 1**. This report identifies the need to:

- Increase the overall transfer capability of the bulk transmission system;
- Ensure sufficient supply capacity to address the forecast load in the Peterborough to Quinte West region and surrounding area and provide flexibility and resiliency in meeting future changes in demand; and
- Mitigate upstream thermal constraints limiting flows into the Ottawa region.

The report concluded that transmission line options connecting Dobbin TS to either Cherrywood TS or Clarington TS would satisfy these needs, and termination at either station was comparable from a cost, scope and capability perspective.

Subsequently, on October 19, 2023, the Lieutenant Governor in Council issued Orders in Council, declaring that construction of the Project is needed in accordance with section 28.6.1 of the Act and that the Project has been determined to be a priority project for purposes of section 96.1(2) of the Act. Copies of the OICs (dated October 19, 2023) and correspondence from the Minister of Energy to the OEB (dated October 23, 2023) directing the OEB to amend Hydro One’s transmission licence in accordance with the OICs are included as **Attachments 1 through 3** of this Schedule. Under this authority, the OEB is required to accept the need for the Project for purposes of this Application.

On November 14, 2023, the OEB issued a Decision and Order (EB-2023-0319) ordering that Hydro One’s Transmission Licence (ET-2003-0035) be amended to include, among others, the following new conditions:

- Develop and seek approval for a new 230 kV transmission line from Dobbin TS to either Cherrywood TS or Clarington TS, including associated station facility expansions or upgrades required at the terminal stations; and

- Develop the project in accordance with the scope and timing recommended by the IESO and file with the OEB a copy of any recommendations from the IESO related to the scope and timing¹.

A copy of the OEB's Decision and Order and amended Hydro One Transmission Licence are included as **Attachment 4 and 5** of this Schedule, respectively.

The IESO supports the proposed Project, consisting of a new 230 kV double-circuit transmission line between Dobbin TS and Clarington TS, as set out in its report completed for this leave to construct application titled "*Supplemental Evidence to Support the Need for the Durham Kawartha Power Line Project*" dated April 2026. Moreover, the IESO reaffirmed the need for the Project as necessary to maintain a reliable electricity supply to Eastern Ontario and to provide the bulk system benefits as defined in this Application. A copy of this report is provided as **Attachment 6** of this Schedule.

¹ Refer to EB-2023-0319.



Ontario

**Executive Council of Ontario
Order in Council**

**Conseil exécutif de l'Ontario
Décret**

On the recommendation of the undersigned, the Lieutenant Governor of Ontario, by and with the advice and concurrence of the Executive Council of Ontario, orders that:

Sur la recommandation de la personne soussignée, le lieutenant-gouverneur de l'Ontario, sur l'avis et avec le consentement du Conseil exécutif de l'Ontario, décrète ce qui suit :

WHEREAS Ontario considers it critical to expand Ontario's transmission system to provide a reliable and adequate supply of electricity to Northeastern and Eastern Ontario to support economic growth and electrification initiatives in the region;

AND WHEREAS the Independent Electricity System Operator, the organization responsible for ensuring the reliability of Ontario's electricity grid, has published:

1. A bulk planning report dated October 27, 2022, entitled the "Need for Northeast Bulk System Reinforcements", which recommended a new transmission line running between Sault Ste. Marie and Sudbury and a new transmission line in the Sudbury region as the appropriate solution required to meet expected demand growth and system needs; and
2. A bulk planning report dated December 8, 2022, entitled the "Gatineau Corridor End-of-Life Study" which recommended a new transmission line between the Peterborough region and the Oshawa/Pickering area as the appropriate solution to meet forecast electricity demand growth and system needs.

AND WHEREAS the Government has determined that the development of the transmission projects should be undertaken by a transmitter that is best positioned to ensure that the infrastructure can be developed expediently and on a timeline that supports economic growth, and that has demonstrated commitment to and progress toward advancing economic participation opportunities for Indigenous communities;

AND WHEREAS the Government has determined that the preferred manner of proceeding is to require Hydro One Networks Inc. to undertake the development of the transmission projects, including taking any and all steps that are deemed to be necessary and desirable in order to seek required approvals and fulfilling, as part of the environmental assessment process and other applicable authorizations and permits, any procedural aspects of the Crown's duty to consult potentially impacted Indigenous communities that may be delegated to it;

AND WHEREAS the Minister of Energy has, with the approval of the Lieutenant Governor in Council, the authority to issue Directives pursuant to section 28.6.1 of the *Ontario Energy Board Act, 1998*, which relate to the construction, expansion or re-enforcement of transmission systems;

NOW THEREFORE the Directive attached hereto is approved and shall be and is effective as of the date hereof.

- - - - -

ATTENDU QUE l'Ontario considère qu'il est essentiel d'étendre le réseau de transport d'électricité de l'Ontario pour offrir un approvisionnement fiable et adéquat en électricité au Nord-Est et à l'Est de l'Ontario afin de soutenir la croissance économique et les projets d'électrification dans la région;

ET ATTENDU QUE la Société indépendante d'exploitation du réseau d'électricité (SIERE), l'organisation qui a la responsabilité de s'assurer de la fiabilité du réseau de distribution d'électricité de l'Ontario, a publié :

1. un rapport de planification d'ensemble du 27 octobre 2022, intitulé « Need for Northeast Bulk System Reinforcements », qui recommandait une nouvelle ligne de transport entre Sault Ste. Marie et Sudbury et une nouvelle ligne de transport dans la région de Sudbury à titre de solution appropriée requise pour répondre à la croissance prévue de la demande et aux besoins du réseau;
2. et un rapport de planification d'ensemble du 8 décembre 2022, intitulé « Gatineau Corridor End-of-Life Study », qui recommandait une nouvelle ligne de transport entre la région de Peterborough et celle d'Oshawa/Pickering à titre de solution appropriée pour répondre à la croissance prévue de la demande en électricité et aux besoins du réseau.

ET ATTENDU QUE le gouvernement a décidé que le développement des projets de transport doit être entrepris par le transporteur le mieux placé pour s'assurer que les infrastructures peuvent être mises en place rapidement et conformément à un calendrier qui soutient la croissance économique, et qui a montré la preuve de son engagement et de ses progrès pour faire avancer les occasions de participation économique pour les communautés autochtones;

ET ATTENDU QUE le gouvernement a décidé que la meilleure façon de procéder consiste à exiger qu'Hydro One Networks Inc. entreprenne le développement des projets de transport, y compris prendre toutes les mesures qui sont jugées nécessaires et souhaitables afin d'obtenir les approbations requises et de remplir, dans le cadre du processus d'évaluation environnementale et des autres autorisations et permis applicables, les aspects procéduraux de l'obligation de la Couronne de consulter les communautés autochtones potentiellement concernées, qui peuvent lui être délégués;

ET ATTENDU QUE le ministre de l'Énergie a, avec l'approbation du lieutenant-gouverneur en conseil, le pouvoir de donner des directives conformément à l'article 28.6.1 de la *Loi de 1998 sur la Commission de l'énergie de l'Ontario*, à l'égard de la construction, de l'extension ou du renforcement des réseaux de transport;

PAR CONSÉQUENT, la directive jointe aux présentes est approuvée et entre en vigueur à la date des présentes.



Recommended: Minister of Energy
Recommandé par : Le ministre de l'Énergie



Concurred: Chair of Cabinet
Appuyé par : Le président | la présidente du Conseil des ministres

Approved and Ordered: OCT 19 2023
Approuvé et décrété le :


Lieutenant Governor
La lieutenante-gouverneure

MINISTER'S DIRECTIVE

TO: THE ONTARIO ENERGY BOARD

I, Todd Smith, Minister of Energy, hereby direct the Ontario Energy Board ("Board") pursuant to section 28.6.1 of the *Ontario Energy Board Act, 1998* as follows:

1. The Board shall amend the conditions of the electricity transmission licence of Hydro One Networks Inc. ("Hydro One") to include a requirement that Hydro One proceed to do the following related to the construction, expansion or reinforcement of its transmission system:
 - i. Develop and seek approvals for the following transmission line projects:
 1. A new 230 kilovolt (kV) transmission line from Mississagi Transformer Station to Third Line Transformer Station, including associated station facility expansions or upgrades required at the terminal stations;
 2. A new 500 kV transmission line from Mississagi Transformer Station to Hanmer Transformer Station, including associated station facility expansions or upgrades required at the terminal stations; and
 3. A new 230 kV transmission line from Dobbin Transformer Station to either Cherrywood Transformer Station or Clarington Transformer Station, including associated station facility expansions or upgrades required at the terminal stations.
 - ii. The scope and timing for the transmission line projects listed in sub-paragraph i above, including the terminal point for the transmission line project listed in clause 3 of that sub-paragraph, shall accord with the recommendations of the IESO.
2. The Board shall require that Hydro One provide such reporting to the Board as the Board may consider appropriate, with respect to budget, timing, and risks in relation to the development of the transmission line projects listed in sub-paragraph 1 i.
3. The Board shall make the amendments to Hydro One's electricity transmission licence without holding a hearing.

DIRECTIVE DU MINISTRE

DESTINATAIRES : LA COMMISSION DE L'ÉNERGIE DE L'ONTARIO

Je, Todd Smith, ministre de l'Énergie, ordonne par les présentes à la Commission de l'énergie de l'Ontario (la « Commission ») conformément à l'article 28.6.1 de la *Loi de 1998 sur la Commission de l'énergie de l'Ontario* ce qui suit :

1. La Commission est tenue de modifier les conditions du permis de transport d'électricité d'Hydro One Networks Inc. (« Hydro One ») afin d'ajouter l'exigence qu'Hydro One procède à ce qui suit dans le cadre de la construction, de l'extension ou du renforcement de son réseau de transport :
 - i. Élaborer les projets de ligne de transport ci-dessous et obtenir les approbations :
 1. Une nouvelle ligne de transport de 230 kilovolts (kV) allant du poste de transformation de Mississagi au poste de transformation de Third Line, y compris les extensions des installations des postes associés ou les mises à niveau requises aux postes d'arrivée;
 2. Une nouvelle ligne de transport de 500 kV allant du poste de transformation de Mississagi au poste de transformation de Hanmer, y compris les extensions des installations des postes associés ou les mises à niveau requises aux postes d'arrivée;
 3. Et une nouvelle ligne de transport de 230 kV allant du poste de transformation de Dobbin au poste de transformation de Cherrywood ou au poste de transformation de Clarington, y compris les extensions des installations des postes associés ou les mises à niveau requises aux postes d'arrivée;
 - ii. La portée et le calendrier des projets de ligne de transport énumérés à l'alinéa i ci-dessus, y compris le point d'arrivée du projet de ligne de transport énuméré à la clause 3 de cet alinéa, doivent concorder avec les recommandations de la SIERE.
2. La Commission exigera qu'Hydro One lui fournisse les rapports qu'elle peut considérer comme appropriés concernant le budget, le calendrier et les risques liés au développement des projets de lignes de transport énumérés à l'alinéa 1 i.
3. La Commission apportera les modifications au permis de transport d'électricité d'Hydro One sans tenir une audience.

Ministry of Energy

Office of the Minister

77 Grenville Street, 10th Floor
Toronto ON M7A 2C1
Tel.: 416-327-6758

Ministère de l'Énergie

Bureau du ministre

77, rue Grenville, 10^e étage
Toronto ON M7A 2C1
Tél. : 416-327-6758



MC-994-2023-778

October 23, 2023

Mr. Glenn O'Farrell,
Chair of the OEB Board of Directors
Ontario Energy Board
2300 Yonge St, 27 Floor
PO Box 2319
Toronto ON M4P 1E4

Dear Mr. O'Farrell:

Electricity demand in northeast and eastern Ontario is projected to grow rapidly over the next decade due to community growth, electrification initiatives and economic development, including advanced manufacturing, Algoma Steel's conversion to electric arc furnaces, and mining for critical minerals. This has underscored the need to mitigate against regulatory delays in the approval processes for critical electricity transmission projects. As we have outlined in our *Powering Ontario's Growth* plan (July 2023), expanding the transmission system is critical to maintaining Ontario's clean energy advantage.

The Independent Electricity System Operator issued a bulk planning report entitled "Need for Northeast Bulk System Reinforcements" in October 2022 and a second bulk planning report entitled "Gatineau End of Life Study" in December 2022. These studies have recommended three new transmission lines come into service no later than 2029, two in northeast Ontario and one in eastern Ontario.

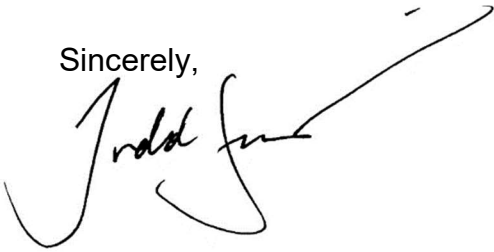
I am writing today to inform you that under the authority of section 96.1(1) of the *Ontario Energy Board Act, 1998* (the Act), the Lieutenant Governor in Council made an order declaring that the construction, expansion or reinforcement of these three transmission lines are needed as priority projects. The Order in Council, which is now effective, is attached to this letter.

...cont'd/

Furthermore, under the authority of section 28.6.1 of the Act, I am, with the approval of the Lieutenant Governor in Council pursuant to Order in Council No. 1532/2023, issuing a directive to the Ontario Energy Board (OEB) to amend Hydro One Networks Inc. (Hydro One)'s electricity transmission licence to include a requirement that it proceed to develop and seek all necessary approvals of these three priority projects. The licence amendments required by this directive will further support the timely development of these transmission lines.

Please do not hesitate to contact my office with any questions.

Sincerely,

A handwritten signature in black ink, appearing to read 'Todd Smith', with a long, sweeping horizontal stroke extending to the right.

The Honourable Todd Smith
Minister of Energy

c: Susanna Zagar, Chief Executive Officer, Ontario Energy Board
Jason Fitzsimmons, Deputy Minister, Ministry of Energy
David Lebeter, President and Chief Executive Officer, Hydro One Networks Inc.
Lesley Gallinger, President and Chief Executive Officer, Independent Electricity
System Operator



Ontario

**Executive Council of Ontario
Order in Council**

**Conseil exécutif de l'Ontario
Décret**

On the recommendation of the undersigned, the Lieutenant Governor of Ontario, by and with the advice and concurrence of the Executive Council of Ontario, orders that:

Sur la recommandation de la personne soussignée, le lieutenant-gouverneur de l'Ontario, sur l'avis et avec le consentement du Conseil exécutif de l'Ontario, décrète ce qui suit :

WHEREAS Ontario considers it critical to expand Ontario's transmission system to provide a reliable and adequate supply of electricity to support economic growth and electrification initiatives throughout Northeastern and Eastern Ontario;

AND WHEREAS Ontario considers the expansion of the electricity network in Northeastern and Eastern Ontario to support economic growth and electrification to be a priority;

AND WHEREAS the Independent Electricity System Operator, the organization responsible for ensuring the reliability of Ontario's electricity grid, has published:

1. A bulk planning report dated October 27, 2022, entitled the "Need for Northeast Bulk System Reinforcements", which recommended a new transmission line running between Sault Ste. Marie and Sudbury and a new transmission line in the Sudbury region as the appropriate solution required to meet expected demand growth and system needs; and
2. A bulk planning report dated December 8, 2022, entitled the "Gatineau Corridor End-of-Life Study" which recommended a new transmission line between the Peterborough region and the Oshawa/Pickering area as the appropriate solution to meet forecast electricity demand growth and system needs.

AND WHEREAS the Lieutenant Governor in Council may make an order under section 96.1 of the *Ontario Energy Board Act, 1998* (the "Act") declaring that the construction, expansion or reinforcement of an electricity transmission line specified in the order is needed as a priority project;

AND WHEREAS an order under section 96.1 of the Act requires the Ontario Energy Board, in considering an application under section 92 of the Act in respect of an electricity transmission line specified in the order, to accept that the construction, expansion or reinforcement is needed when forming its opinion under section 96 of the Act;

NOW THEREFORE it is hereby declared pursuant to section 96.1 of the Act that the construction, expansion or reinforcement of the following electricity transmission lines are needed as priority projects:

O.C. | Décret : 1531 / 2023

1. A new 230 kilovolt (kV) transmission line from Mississagi Transformer Station to Third Line Transformer Station, including associated station facility expansions or upgrades required at the terminal stations;
2. A new 500 kV transmission line from Mississagi Transformer Station to Hanmer Transformer Station, including associated station facility expansions or upgrades required at the terminal stations; and
3. A new 230 kV transmission line from Dobbin Transformer Station to either Cherrywood Transformer Station or Clarington Transformer Station, including associated station facility expansions or upgrades required at the terminal stations.

ATTENDU QUE l'Ontario considère qu'il est essentiel d'étendre le réseau de transport d'électricité de l'Ontario afin d'offrir un approvisionnement fiable et adéquat en électricité pour soutenir la croissance économique et les projets d'électrification dans le Nord-Est et l'Est de l'Ontario;

ET ATTENDU QUE l'Ontario considère l'extension du réseau électrique au Nord-Est et à l'Est de l'Ontario pour soutenir la croissance économique et l'électrification comme des priorités;

ET ATTENDU QUE la Société indépendante d'exploitation du réseau d'électricité (SIERE), l'organisation qui a la responsabilité de s'assurer de la fiabilité du réseau de distribution d'électricité de l'Ontario, a publié :

1. un rapport de planification d'ensemble du 27 octobre 2022, intitulé « Need for Northeast Bulk System Reinforcements », qui recommandait une nouvelle ligne de transport entre Sault Ste. Marie et Sudbury et une nouvelle ligne de transport dans la région de Sudbury à titre de solution appropriée requise pour répondre à la croissance prévue de la demande et aux besoins du réseau;
2. et un rapport de planification d'ensemble du 8 décembre 2022, intitulé « Gatineau Corridor End-of-Life Study », qui recommandait une nouvelle ligne de transport entre la région de Peterborough et celle d'Oshawa/Pickering à titre de solution appropriée pour répondre à la croissance prévue de la demande en électricité et aux besoins du réseau.

ET ATTENDU QUE le lieutenant-gouverneur en conseil peut, en vertu de l'article 96.1 de *Loi de 1998 sur la Commission de l'énergie de l'Ontario* (la « Loi »), par décret, déclarer que la construction, l'extension ou le renforcement d'une ligne de transport d'électricité précisée dans un décret est nécessaire à titre de projet prioritaire;

ET ATTENDU QU'un décret pris en vertu de l'article 96.1 de la Loi exige que la Commission de l'énergie de l'Ontario, lors de l'examen d'une requête présentée en vertu de l'article 92 de la Loi concernant une ligne de transport d'électricité précisée dans le décret, accepte le fait que la construction, l'extension ou le renforcement est nécessaire lorsqu'elle se fait une opinion dans le cadre de l'article 96;

PAR CONSÉQUENT, il est déclaré aux présentes que conformément à l'article 96.1 de La Loi, la construction, l'extension ou le renforcement des lignes de transport d'électricité ci-dessous sont nécessaires à titre de projets prioritaires :

1. Une nouvelle ligne de transport de 230 kilovolts (kV) allant du poste de transformation de Mississagi au poste de transformation de Third Line, y compris les extensions des installations des postes associés ou les mises à niveau requises aux postes d'arrivée.
2. Une nouvelle ligne de transport de 500 kV allant du poste de transformation de Mississagi au poste de transformation de Hanmer, y compris les extensions des installations des postes associés ou les mises à niveau requises aux postes d'arrivée.
3. Une nouvelle ligne de transport de 230 kV allant du poste de transformation de Dobbin au poste de transformation de Cherrywood ou au poste de transformation de Clarington, y compris les extensions des installations des postes associés ou les mises à niveau requises aux postes d'arrivée.



Recommended: Minister of Energy
Recommandé par : Le ministre de l'Énergie



Concurred: Chair of Cabinet
Appuyé par : Le président | la présidente du Conseil des ministres

Approved and Ordered:
Approuvé et décrété le : OCT 19 2023



Lieutenant Governor
La lieutenante-gouverneure



Ontario
Energy
Board | Commission
de l'énergie
de l'Ontario

DECISION AND ORDER

EB-2023-0319

Amending the Electricity Transmission Licence of Hydro One Networks Inc. to Require it to Develop and Seek Approvals for New Transmission Lines

BY DELEGATION, BEFORE: Brian Hewson
Vice President,
Consumer Protection & Industry Performance

November 14, 2023

INTRODUCTION AND SUMMARY

Further to a directive from the Minister of Energy (Minister), the Ontario Energy Board (OEB), of its own motion, is commencing this proceeding to amend the electricity transmission licence¹ of Hydro One Networks Inc. (Hydro One) to require it to develop and seek approvals for three new transmission line projects.

BACKGROUND

Under section 28.6.1 of the *Ontario Energy Board Act, 1998* (Act), the Minister may issue directives to the OEB requiring the OEB to take such steps as are specified in the directive relating to the construction, expansion or reinforcement of transmission systems. Such a directive may, among other things, require the OEB to amend the licence conditions of a transmitter to require the transmitter to take the actions specified in the directive in relation to its transmission system. Such a directive may also specify whether the OEB is to hold a hearing for the purposes of implementing the directive.

The OEB received a [directive](#) under section 28.6.1 of the Act (Directive) from the Minister, which was approved by the Lieutenant Governor in Council on October 19, 2023 as Order in Council No. 1532/2023. The Directive requires the OEB to amend Hydro One's electricity transmission licence to require Hydro One to develop and seek approvals for the following three transmission line projects (collectively referred to as the Projects):

1. A new 230 kilovolt (kV) transmission line from Mississagi Transformer Station to Third Line Transformer Station, including associated station facility expansions or upgrades required at the terminal stations;
2. A new 500 kV transmission line from Mississagi Transformer Station to Hanmer Transformer Station, including associated station facility expansions or upgrades required at the terminal stations; and
3. A new 230 kV transmission line from Dobbin Transformer Station to either Cherrywood Transformer Station or Clarington Transformer Station, including associated station facility expansions or upgrades required at the terminal stations.

The Order in Council accompanying the Directive states that it is critical to expand Ontario's transmission system to provide a reliable and adequate supply of electricity to Northeastern and Eastern Ontario to support economic growth and electrification initiatives in the region.

¹ ET-2003-0035

The Directive also requires that the scope and timing for the development of the Projects accord with the recommendations of the IESO, and further directs the OEB to require that Hydro One provide such reporting to the OEB as the OEB may consider appropriate with respect to budget, timing and risks in relation to the development of the Projects.

In accordance with the Directive, the OEB is required to amend Hydro One's electricity transmission licence without a hearing.

This Decision and Order is being issued by Delegated Authority without a hearing.

DECISION

Further to the Directive, the OEB is amending Hydro One's electricity transmission licence to require it to develop and seek approvals for the Projects in accordance with the recommendations of the IESO.

With respect to reporting requirements, as an initial step, the OEB is requiring Hydro One to file a copy of any recommendations received from the IESO related to the scope and timing of the development of the Projects. Further reporting requirements to enable the OEB to monitor Hydro One's progress towards the implementation of the conditions being added to its electricity transmission licence today, including budget and risks, will be addressed at a later date.

IT IS ORDERED THAT:

1. Hydro One Networks Inc.'s electricity transmission licence ET-2003-0035 is amended by adding the following new conditions:

19.9.1 The Licensee shall develop and seek approval for the following three transmission line projects:

- a) A new 230 kilovolt (kV) transmission line from Mississagi Transformer Station to Third Line Transformer Station, including associated station facility expansions or upgrades required at the terminal stations;
- b) A new 500 kV transmission line from Mississagi Transformer Station to Hanmer Transformer Station, including associated station facility expansions or upgrades required at the terminal stations; and

- c) A new 230 kV transmission line from Dobbin Transformer Station to either Cherrywood Transformer Station or Clarington Transformer Station, including associated station facility expansions or upgrades required at the terminal stations.

19.9.2 The scope and timing for the development of the projects set out in condition 19.9.1, including the terminal point for the transmission line project listed in c), shall accord with the recommendations of the Independent Electricity System Operator.

- 2. Hydro One Networks Inc. shall, no later than December 20, 2023, file with the OEB a copy of any recommendations received from the Independent Electricity System Operator related to the scope and timing of the development of the projects.

DATED at Toronto, November 14, 2023

ONTARIO ENERGY BOARD



Brian Hewson
Vice President, Consumer Protection & Industry Performance



Electricity Transmission Licence

ET-2003-0035

Hydro One Networks Inc.

Valid Until

October 30, 2043

A handwritten signature in black ink, appearing to be "BH", with a long horizontal line extending to the right.

Brian Hewson
Vice President, Consumer Protection & Industry Performance
Ontario Energy Board

Date of Issuance: October 31, 2023
Date of Amendment: November 14, 2023

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th Floor
Toronto, ON M4P 1E4

Commission de l'énergie de l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4

LIST OF AMENDMENTS

OEB File No.	Date of Amendment
EB-2002-0501	August 11, 2004
EB-2011-0055	February 28, 2011
EB-2013-0437	January 9, 2014
EB-2015-0262	November 26, 2015
EB-2015-0270	November 26, 2015
EB-2020-0309	December 23, 2020
EB-2022-0142	April 6, 2022
EB-2022-0085	May 6, 2022
EB-2023-0275	October 31, 2023 – licence renewal date
EB-2023-0319	November 14, 2023

	Table of Contents	Page No.
1	Definitions	1
2	Interpretation	2
3	Authorization	2
4	Obligation to Comply with Legislation, Regulations and Market Rules	2
5	Obligation to Comply with Codes	2
6	Requirement to Enter into an Operating Agreement	2
7	Obligation to Provide Non-discriminatory Access	3
8	Obligation to Connect.....	3
9	Obligation to Maintain System Integrity	3
10	Transmission Rates and Charges.....	3
11	Separation of Business Activities	4
12	Expansion of Transmission System.....	4
13	Provision of Information to the Board.....	4
14	Restrictions on Provision of Information	4
15	Term of Licence	5
16	Transfer of Licence	5
17	Amendment of Licence	5
18	Fees and Assessments.....	5
19	Expansion and Upgrading of Transmission System Further to Ministerial Directive.....	5

20	Communication	7
21	Copies of the Licence.....	7
SCHEDULE 1 SPECIFICATION OF TRANSMISSION FACILITIES.....		8
SCHEDULE 2 LIST OF CODE EXEMPTIONS		9

1 Definitions

In this Licence:

“Accounting Procedures Handbook” means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

“Act” means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

“Affiliate Relationships Code for Electricity Distributors and Transmitters” means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

“Board” means the Ontario Energy Board;

“Electricity Act” means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

“Licensee” means Hydro One Networks Inc.;

“Market Rules” means the rules made under section 32 of the Electricity Act;

“Performance Standards” means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

“Rate Order” means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

“transmission services” means services related to the transmission of electricity and the services the Board has required transmitters to carry out for which a charge or rate has been established in the Rate Order;

“Transmission System Code” means the code approved by the Board and in effect at the relevant time, which, among other things, establishes the obligations of a transmitter with respect to the services and terms of service to be offered to customers and provides minimum technical operating standards of transmission systems;

“wholesaler” means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

- 2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens. Where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

- 3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence to own and operate a transmission system consisting of the facilities described in Schedule 1 of this Licence, including all associated transmission equipment.

4 Obligation to Comply with Legislation, Regulations and Market Rules

- 4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.
- 4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

- 5.1 The Licensee shall at all times comply with the following Codes (collectively the “Codes”) approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the Licensee are set out in Schedule 2 of this Licence. The following Codes apply to this Licence:
- a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; and
 - b) the Transmission System Code.
- 5.2 The Licensee shall:
- a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and
 - b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Requirement to Enter into an Operating Agreement

- 6.1 The Licensee shall enter into an agreement (“Operating Agreement”) with the IESO providing for the direction by the IESO of the operation of the Licensee’s transmission system. Following a request made by the IESO, the Licensee and the IESO shall enter into an Operating Agreement

within a period of 90 business days, unless extended with leave of the Board. The Operating Agreement shall be filed with the Board within ten (10) business days of its completion.

- 6.2 Where there is a dispute that cannot be resolved between the parties with respect to any of the terms and conditions of the Operating Agreement, the IESO or the Licensee may apply to the Board to determine the matter.

7 Obligation to Provide Non-discriminatory Access

- 7.1 The Licensee shall, upon the request of a consumer, generator, distributor or retailer, provide such consumer, generator, distributor or retailer, as the case may be, with access to the Licensee's transmission system and shall convey electricity on behalf of such consumer, generator, distributor or retailer in accordance with the terms of this Licence, the Transmission System Code and the Market Rules.

8 Obligation to Connect

- 8.1 If a request is made for connection to the Licensee's transmission system or for a change in the capacity of an existing connection, the Licensee shall respond to the request within 30 business days.
- 8.2 The Licensee shall process connection requests in accordance with published connection procedures and participate with the customer in the IESO's Connection Assessment and approval process in accordance with the Market Rules, its Rate Order(s) and the Transmission System Code.
- 8.3 An offer of connection shall be consistent with the terms of this Licence, the Market Rules, the Rate Order, and the Transmission System Code.
- 8.4 The terms of such offer to connect shall be fair and reasonable.
- 8.5 The Licensee shall not refuse to make an offer to connect unless it is permitted to do so by the Act or any Codes, standards or rules to which the Licensee is obligated to comply with as a condition of this Licence.

9 Obligation to Maintain System Integrity

- 9.1 The Licensee shall maintain its transmission system to the standards established in the Transmission System Code and Market Rules, and have regard to any other recognized industry operating or planning standards required by the Board.

10 Transmission Rates and Charges

- 10.1 The Licensee shall not charge for the connection of customers or the transmission of electricity except in accordance with the Licensee's Rate Order(s) as approved by the Board and the Transmission System Code.

11 Separation of Business Activities

- 11.1 The Licensee shall keep financial records associated with transmitting electricity separate from its financial records associated with distributing electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

12 Expansion of Transmission System

- 12.1 The Licensee shall not construct, expand or reinforce an electricity transmission system or make an interconnection except in accordance with the Act and Regulations, the Transmission System Code and the Market Rules.

13 Provision of Information to the Board

- 13.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.
- 13.2 Without limiting the generality of paragraph 13.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) business days past the date upon which such change occurs.

14 Restrictions on Provision of Information

- 14.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator, obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.
- 14.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:
- a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;
 - b) for billing, settlement or market operations purposes;
 - c) for law enforcement purposes; or
 - d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.
- 14.3 Information regarding consumers, retailers, wholesalers or generators may be disclosed where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.
- 14.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.
- 14.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information is not be used for any other purpose except the purpose for which it was disclosed.

15 Term of Licence

- 15.1 This Licence shall take effect on October 31, 2023 and expire on October 30, 2043. The term of this Licence may be extended by the Board.

16 Transfer of Licence

- 16.1 In accordance with subsection 18(2) of the Act, this Licence is not transferable or assignable without leave of the Board.

17 Amendment of Licence

- 17.1 The Board may amend this Licence in accordance with section 74 of the Act or section 38 of the Electricity Act.

18 Fees and Assessments

- 18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Expansion and Upgrading of Transmission System Further to Ministerial Directive

- 19.1 The Licensee shall, for the purposes of accommodating the safe connection of renewable energy generation facilities, immediately following February 28, 2011 work in co-operation with the Ontario Power Authority to establish the scope and timing of the transmission projects referred to in paragraphs 19.2 and 19.3.
- 19.2 The Licensee shall develop and seek approvals for the following transmission projects, the scope and timing of which shall be in accordance with the recommendations of the Ontario Power Authority made in the course of the Ontario Power Authority's transmission planning activities conducted in accordance with its objects, as well as those identified in a Directive issued to the Ontario Power Authority by the Minister of Energy on February 17, 2011 under section 25.30 of the *Electricity Act, 1998*:
- a) upgrade one or more existing transmission lines west of the City of London; and
 - b) a new transmission line west of the City of London.
- 19.3 The Licensee shall develop and implement the following transmission projects, the scope and timing of which shall be in accordance with the recommendations of the Ontario Power Authority made in the course of the Ontario Power Authority's transmission planning activities conducted in accordance with its objects, as well as those identified in a Directive issued to the Ontario Power Authority by the Minister of Energy on February 17, 2011 under section 25.30 of the *Electricity Act, 1998*:
- a) one or more devices to enhance transfer capability, such as series or static var compensation or other similar devices, in Southwestern Ontario; and
 - b) increase short circuit and/or transformer capacity at up to fifteen of the Licensee's transmission stations during the forty-eight month period beginning February 28, 2011 , to enable the connection of small-scale renewable energy generation facilities.

- 19.4 Paragraph 19.3 in no way limits the obligation of the Licensee to obtain all necessary approvals for the transmission projects referred to in that paragraph.
- 19.5 Immediately following January 9, 2014 the Licensee shall, for the purposes of accommodating load due to forecast demand growth over the long term, promoting the use of clean and renewable energy sources from Ontario's supply mix, and enhancing opportunities for the development and connection of new renewable generation facilities over the long term, work in co-operation with the Ontario Power Authority to establish the scope and timing of the transmission project referred to in paragraph 19.6.
- 19.6 The Licensee shall develop and seek approvals for the expansion or reinforcement of a portion or portions of the Licensee's electricity transmission network in the area west of Thunder Bay (the "Northwest Bulk Transmission Line Project"). The scope and timing of the Northwest Bulk Transmission Line Project shall be in accordance with the recommendations of the Ontario Power Authority made in the course of the Ontario Power Authority's transmission planning activities conducted in accordance with its statutory mandate, objects and responsibilities under the *Electricity Act, 1998*, including with any transmission planning activities identified in any direction issued, or to be issued, by the Minister of Energy to the Ontario Power Authority pursuant to Part II.2 of the *Electricity Act, 1998*.
- 19.7 The Licensee shall develop and seek approvals for a new 230 kilovolt double-circuit transmission line from the existing Chatham Switching Station to the new Lakeshore Transformer Station to be located at Leamington Junction (Chatham to Lakeshore Line), including associated station facilities to connect the Chatham to Lakeshore Line at the terminal stations. Development of the Chatham to Lakeshore Line shall accord with the project scope and timing recommended by the Independent Electricity System Operator.
- 19.8.1 The Licensee shall develop and seek approvals for the following four transmission line projects:
- a) A new 230 kilovolt (kV) transmission line from Lambton Transformer Station to Chatham Switching Station, including associated station facility expansions or upgrades required at the terminal stations;
 - b) A new 500 kV transmission line from Longwood Transformer Station to Lakeshore Transformer Station, including associated station facility expansions or upgrades required at the terminal stations;
 - c) A second new 500 kV transmission line from Longwood Transformer Station to Lakeshore Transformer Station, including associated station facility expansions or upgrades required at the terminal stations; and
 - d) A new 230 kV transmission line that connect the Windsor area to the Lakeshore Transformer Station, including associated station facility expansions or upgrades required at the terminal stations.
- 19.8.2 Development of the projects set out in condition 19.8.1 shall accord with the project scope and timing recommended by the Independent Electricity System Operator.
- 19.9.1 The Licensee shall develop and seek approval for the following three transmission line projects:

- a) A new 230 kilovolt (kV) transmission line from Mississagi Transformer Station to Third Line Transformer Station, including associated station facility expansions or upgrades required at the terminal stations;
- b) A new 500 kV transmission line from Mississagi Transformer Station to Hanmer Transformer Station, including associated station facility expansions or upgrades required at the terminal stations; and
- c) A new 230 kV transmission line from Dobbin Transformer Station to either Cherrywood Transformer Station or Clarington Transformer Station, including associated station facility expansions or upgrades required at the terminal stations.

19.9.2 The scope and timing for the development of the projects set out in condition 19.9.1, including the terminal point for the transmission line project listed in c), shall accord with the recommendations of the Independent Electricity System Operator.

20 Communication

- 20.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.
- 20.2 All official communication relating to this Licence shall be in writing.
- 20.3 All written communication is to be regarded as having been given by the sender and received by the addressee:
- a) when delivered in person to the addressee by hand, by registered mail or by courier;
 - b) ten (10) business days after the date of posting if the communication is sent by regular mail; and
 - c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

21 Copies of the Licence

- 21.1 The Licensee shall:
- a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and
 - b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

SCHEDULE 1 SPECIFICATION OF TRANSMISSION FACILITIES

This Schedule specifies the facilities over which the Licensee is authorized to transmit electricity in accordance with paragraph 3 of this Licence.

1. The transmission system and facilities of Hydro One Networks Inc. are depicted in the attached diagram and include transmission lines, transformation stations and all associated facilities. Hydro One may alter this diagram from time to time and shall file it with the Board, upon receipt of which the updated diagram shall be deemed to be the specification of transmission facilities under this schedule.

SCHEDULE 2 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the licensee has been exempted.

1. The Licensee is exempted from Section 1.2.1 of Schedule E of Appendix 1 of the Transmission System Code so as to allow the Licensee:
 - to enter into a connection agreement with certain proposed customers on terms and conditions other than those set forth in the said section 1.2.1; and
 - to amend connection agreements already entered into by the licensee with customers, such that they may be amended to contain terms and conditions other than those set forth in the said section 1.2.1.
2. The modifications to the connection agreement are attached as Schedules 3 and 4 to this Licence. Schedule 3 contains changes needed to address legacy system configuration issues as well as operating concerns affecting all generating stations owned by OPG and Bruce Power. Schedule 4 contains changes needed to comply with the operational requirements of nuclear generating facilities, facilitate compliance with Power Reactor Operating Licences, issued by the Canadian Nuclear Safety Commission ("CNSC").
3. The Licensee is exempted from Sections 4.1.1 and 4.1.2 of the Transmission System Code for the purpose of entering into a Transmission Connection Agreement with Oneida Energy Storage LP for the connection of a 250 MW battery energy storage facility to its transmission system in the form approved in the OEB's Decision and Order in EB-2022-0085.

Supplemental Evidence to Support the Need for the Durham-Kawartha Power Line Project

Independent Electricity System Operator

Summary

The Independent Electricity System Operator ("IESO") provides this evidence in accordance with Chapter 4, Section 4.3.2.3 of the Ontario Energy Board's ("OEB's") Filing Requirements for Electricity Transmission Applications (the "Filing Requirements") to identify the linkages and interdependencies between Hydro One Networks Inc.'s ("Hydro One") proposed construction of the Durham-Kawartha Power Line Project (the "Project") and the findings of applicable IESO planning studies. It also provides additional information on the need for the Project.

The Project involves the development of a new 230 kV double-circuit transmission line between Clarington Transformer Station ("TS") and Dobbin TS to provide an additional bulk electricity supply path into the Peterborough-to-Quinte West area.

The IESO supports the proposed Project as it aligns with the outcomes of IESO regional and bulk electricity system planning activities for Eastern Ontario. Forecast electricity demand growth in the Peterborough-to-Quinte West area was identified through the IESO's [2021 Peterborough-to-Kingston Integrated Regional Resource Plan \(IRRP\)](#), which concluded that additional transmission supply would be required to meet future needs. The identification and development of solutions to address this growth were undertaken through the subsequent 2022 Gatineau Corridor End-of-Life Study ("Gatineau EOL Study"). The study evaluated technically and economically feasible options to address this need and identified the Project as a key transmission component of the recommended integrated solution, supporting reliable electricity supply to the Peterborough-to-Quinte West and Ottawa areas and the secure operation of the broader Eastern Ontario bulk system.

Relationship to regional plans and/or IESO bulk plans

Linkages and Interdependencies

The need for additional electricity supply capability in the Peterborough-to-Quinte West area was identified through the IESO's 2021 Peterborough-to-Kingston Integrated Regional Resource Plan. Given that addressing this need required upstream bulk system reinforcements, solution options were subsequently evaluated through the 2022 Gatineau EOL Study, a bulk electricity system planning study. The Gatineau EOL Study identified an integrated solution, of which the Durham-Kawartha Power Line Project is a key transmission component. The recommendations of the Gatineau EOL Study included the Project, refurbishment of all 800 km of 230 kV circuits on the Gatineau Corridor identified as nearing EOL,¹ up to 230 MW of additional energy efficiency and expanding the remedial action schemes (RAS)².

¹ Achieved through a Like-for-Like System Impact Assessment (SIA).

² Achieved through the SIA.

The Gatineau EOL Study also identified the need for a new 230 kV double circuit transmission line to provide an additional bulk electricity supply path between the Greater Toronto Area East and the Peterborough-to-Quinte West areas. The Gatineau EOL Study evaluated two feasible termination points for the Project in the Greater Toronto Area East – Cherrywood TS and Clarington TS – and concluded that both options could be developed at a comparable cost while providing similar system benefits. Accordingly, the selection of the preferred termination point was delegated to Hydro One in its role as transmitter. Following its assessment, Hydro One determined that termination at Clarington TS was the preferred option.

Subsequent regional and bulk electricity system planning activities undertaken by the IESO, including the ongoing regional planning activities for Peterborough-to-Kingston IRRP and the ongoing bulk planning activities for Eastern Ontario Bulk Plan, have been completed on the basis that the Project will proceed. This consistent treatment across planning studies reflects the Project's established role in addressing identified regional needs and maintains alignment between regional and bulk electricity system planning for Eastern Ontario.

Costs

Project cost estimates are provided in Table 4 of the Gatineau EOL Study. The estimated cost for the recommended solution is between \$600 million and \$650 million (2021 dollars). This integrated solution includes both the cost of the Project and the like-for-like refurbishment of two existing circuits that are approaching EOL and terminate further east in the Ottawa and Chats Falls areas.

Electricity system benefits

The [Gatineau EOL study](#) states that the integrated package of solutions, including the Project, is needed to ensure the Peterborough to Quinte West area and Ottawa have a reliable supply of electricity that can meet future needs, with both load areas explicitly identified as requiring improved supply capability.

Specifically, the Project would provide key system benefits by ensuring reliability in the Peterborough to Quinte West area is sufficient for the next 20 years, including through improving the area's Load Meeting Capability from approximately 270 MW to 440 MW. This enhanced system would support the forecasted demand growth and enable continued economic growth across the region.

Conclusion

The IESO supports the Project as necessary to maintain a reliable electricity supply to Eastern Ontario. The Project is consistent with regional planning for the Peterborough-to-Kingston region, including the 2021 IRRP and the ongoing IRRP, as well as with broader bulk system planning for Eastern Ontario such as the Gatineau EOL Study and the ongoing Eastern Ontario bulk study. The Project continues to be reflected in regional and bulk system planning studies, contributing to alignment and consistency across the IESO's long-term planning framework for Eastern Ontario. Based on these considerations, the IESO supports the development of the Project in accordance with the recommendations of the Gatineau EOL Study.

**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](https://twitter.com/IESO_Tweets)

 [linkedin.com/company/IESO](https://www.linkedin.com/company/IESO)

PROJECT CATEGORIZATION AND CLASSIFICATION

PROJECT CATEGORIZATION

Subsection 4.3.2.4 of the OEB'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 proposed Project is properly categorized as a non-discretionary project as it is a priority transmission project declared by the Lieutenant Governor in Council and is being undertaken to comply with a mandatory requirement to satisfy obligations specified by the OEB in Hydro One's Transmission Licence as described in **Exhibit B, Tab 3, Schedule 1**.

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 sufficient supply capacity to address the forecast load in the region, while providing flexibility and resiliency to meet future changes in demand and maintain a reliable electricity supply to Eastern Ontario.

Categorization and Classification

		Project Need	
		Non-Discretionary	Discretionary
Project Class	Development	X	
	Connection		
	Sustainment		

COST BENEFIT ANALYSIS AND OPTIONS

There are no practical alternatives to the scope of work for which Hydro One is seeking the OEB's approval. As described in **Exhibit B, Tab 3, Schedule 1**, with the approval of the Lieutenant Governor in Council, as recommended by the Minister of Energy, the Project was designated as a priority project. Furthermore, Hydro One completed the mandated Class EA process in accordance with the *Ontario Environmental Assessment Act*, and the Project route was determined in accordance with those requirements.

An analysis of the alternatives to meet the system needs in the region was undertaken by the IESO, including both wires and non-wires alternatives, as documented in Section 7 of the IESO bulk system report in **Exhibit H, Tab 1, Schedule 1, Attachment 1**. The IESO concluded that construction of a 230 kV transmission line from Dobbin TS to either Cherrywood TS or Clarington TS was the most effective way to address the long-term capacity needs in the region. The IESO further highlighted that terminating the transmission line at either Cherrywood TS or Clarington TS was comparable from a cost, scope and capability perspective.

As documented in **Exhibit B, Tab 3, Schedule 1, Attachment 6**, the IESO supports the proposed Project as defined in this Application. Moreover, the IESO has confirmed the need for the Project to maintain a reliable electricity supply to Eastern Ontario. Since the IESO's recommendation specifies what is required to address the system need (i.e., a 230 kV double-circuit transmission line from Dobbin TS) no other alternatives were considered.

1.0 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 region, and b) 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 – 795 kmil ACSR conductor
2. Alternative 2 – 997.2 kmil ACSR/TW conductor
3. Alternative 3 – 1192.5 kmil ACSR conductor
4. Alternative 4 – 1443.7 kmil ACSR/TW conductor

Analysis and Recommendations

All conductor alternatives listed above address the supply capacity needs in the region while maintaining the reliable and secure operation of the electricity system. 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.¹

Table 1 - Screening Analysis

	Alt. #1 (795 kmil ACSR)	Alt. #2 (997.2 kmil ACSR/TW)	Alt. #3 (1192.5 kmil ACSR)	Alt. #4 (1443.7 kmil ACSR/TW)
Net Capital Cost ^[2] (\$M)	343.43	340.08	341.72	335.21
Losses at Peak Flow ^[3] (MW)	13.92	11.44	9.96	8.26
Losses at System Peak (MW)	0.66	0.54	0.47	0.39
Annual Revenue Costs (\$M)	26.01	25.76	25.88	25.39
Annual Cost of Capital to Cover Losses (\$M)	0.11	0.09	0.08	0.06
Annual Cost of Energy Losses (\$M)	6.48	5.33	4.64	3.85
Annual Cost of Losses ^[4] (\$M)	6.59	5.42	4.72	3.91
Total Annual Cost ^[5] (\$M)	32.60	31.17	30.60	29.30

¹ As filed in proceeding EB-2023-0197, Exhibit I, Tab 2, Schedule 1, Attachment 1.

² Net Capital Cost is the total line cost to deliver the Project net of removals, based on a project definition equivalent to a Class 3 under the AACE estimate classification system for all alternatives.

³ Losses based on 2039 forecast flows.

⁴ 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).

⁵ Total Annual Cost is the summation of Annual Revenue Costs and Annual Cost of Losses.

The screening analysis resulted in no change in alternative ranking; however, the transmission line losses were deemed to be material given the line loss differential between the alternatives. As such, Hydro One conducted a detailed 50-year NPV analysis, using a 5.65% discount rate, to evaluate which conductor alternative provided the best NPV result. 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 \$164,052/MW consistent with Hydro One's Transmission Line Loss Guideline.

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

Table 2 - NPV Sensitivity Analysis of Alternatives

	Alt. #1 (795 kcmil ACSR)	Alt. #2 (997.2 kcmil ACSR/TW)	Alt. #3 (1192.5 kcmil ACSR)	Alt. #4 (1443.7 kcmil ACSR/TW)
Net Capital Cost ^[6] (\$M)	343.43	340.08	341.72	335.21
Annual Losses (MWHR)	27,623	22,688	19,762	16,382
Losses at System Peak (MW)	0.66	0.54	0.47	0.39
Net Present Value (\$M)				
Price	Alt. #1 (795 kcmil ACSR)	Alt. #2 (997.2 kcmil ACSR/TW)	Alt. #3 (1192.5 kcmil ACSR)	Alt. #4 (1443.7 kcmil ACSR/TW)
Energy Price of \$53.16/MWHR and Capacity Price of \$164,052/MW	-332.52	-322.93	-320.33	-310.19
Energy Price of \$120/MWHR ^[7] and Capacity Price of \$164,052/MW	-376.70	-359.21	-351.93	-336.38

The NPV analysis shows that Alternative #4 is the most economic alternative. All four alternatives meet the capacity needs for the region but based on the analysis above, Alternative #4 is selected as the preferred and recommended alternative.

⁶ Net Capital Cost is the total line cost to deliver the Project net of removals, based on a project definition equivalent to a Class 3 under the AACE estimate classification system for all alternatives.

⁷ 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 bulk system report and supplemental need evidence provided as **Attachment 1 of Exhibit H, Tab 1, Schedule 1** and **Attachment 6 of Exhibit B, Tab 3, Schedule 1**, respectively.

In summary, the proposed Project's transmission line facilities will ensure sufficient bulk transfer capability to reliably supply the increasing electricity demand in the Peterborough to Quinte West region and surrounding area, while providing flexibility and resiliency in meeting future changes in demand. The new 230 kV transmission line will also mitigate upstream thermal constraints limiting Ottawa. As highlighted by the IESO, the Project is a key transmission component of their recommended integrated solution for the Gatineau transmission corridor, supporting reliable electricity supply to the Peterborough to Quinte West and Ottawa regions and the secure operation of the broader Eastern Ontario bulk transmission system, in the most feasible and cost-effective manner.

The selected transmission corridor route, established in the Final ESR¹, sustainably minimizes overall impacts to the natural and socio-economic environment by utilizing existing transmission corridor lands along approximately 95% of the 55 km line length. This approach of repurposing existing infrastructure and facilities aligns with the Ministry of Municipal Affairs and Housing's *Provincial Planning Statement, 2024*²; which encourages the reuse of corridors and co-location of linear infrastructure where appropriate.

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 ASCR/TW conductor is the most prudent conductor alternative to meet the needs of

¹ [Hydro One's Durham Kawartha Power Line Class EA Final ESR](#) (January 30, 2026).

² Ministry of Municipal Affairs and Housing's Provincial Planning Statement, 2024, under the Planning Act, Policy 3.3.4 and 3.3.5, p. 17.

1 the Project. The results of that analysis are further discussed in **Exhibit B, Tab 5,**
2 **Schedule 1.**

3
4 Furthermore, the Project will bring both short-term and long-term employment, training,
5 and business opportunities to the region. This includes opportunities for both Indigenous
6 and non-Indigenous communities, governments, and businesses to benefit from the
7 construction, operation, and maintenance of the Project. Hydro One is collaborating with
8 Indigenous communities and governments in the region. To advance action on
9 reconciliation, seven local First Nations will have the opportunity to invest in a 50 per cent
10 equity stake in the transmission line component of the Project through Hydro One's First
11 Nations equity partnership model. The Project will meet Provincial energy needs while
12 providing innovative and lasting benefits to Indigenous governments and communities in
13 procurement, employment, economic benefits and investment opportunities.

APPORTIONING PROJECT COSTS AND RISKS

The estimated total capital cost of the proposed Project is \$428.2¹. 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	37,747
Labour	49,212
Equipment Rental & Contractor Costs	112,947
Sundry	17,725
Contingencies	28,640
Overhead ²	6,185
Allowance for Funds Used During Construction ³	25,826
Real Estate	56,925
Total Line Work ⁴	\$335,207

Table 2 - Station Cost

	Estimated Cost (\$000's)
Materials	20,528
Labour	32,974
Rental Equipment & Contractor Costs	14,421
Sundry	1,017
Contingencies	12,990
Overhead ²	4,994
Allowance for Funds Used During Construction ³	6,033
Real Estate	0
Total Station Work ⁵	\$92,957

¹ There will be an additional \$5.1M of OMA removal costs associated with constructing this Project.

² Overhead Costs allocated to the Project are for corporate services costs. These overhead costs are charged through an ECI-EPC overhead capitalization rate (EB-2023-0198) for the line costs of the Project and Hydro One's standard overhead capitalization rate (EB-2021-0110) for the station costs. As such, they are considered "Indirect Overhead".

³ AFUDC is calculated using the OEB's approved interest rate methodology (EB-2016-0160) to the Project's forecast monthly cash flow and carrying forward closing balances from the preceding month.

⁴ The Total Line Cost includes the skywire upgrades required on the transmission line (Circuit X1P) emanating out of Dobbin TS due to increased fault levels resulting from the construction of the proposed Project.

⁵ The Total Station Cost includes modifications at the terminal stations (including upgrades at Dobbin TS to address increased fault levels and to implement necessary circuit reconfigurations), along with protection upgrades at four remote stations to accommodate the construction of the proposed Project.

1 The cost of the work provided in Tables 1 and 2 of this Schedule is predicated on the
2 timing of the approval, design and construction activities provided in the Project Schedule
3 at **Exhibit B, Tab 11, Schedule 1**. This cost estimates and similarly the Project Schedule,
4 are based on a project definition equivalent to a Class 3⁶ under the AACE International
5 (formerly the Association for the Advancement of Cost Engineering) estimate classification
6 system⁷. Accordingly, the Project has proceeded with selection and procurement of long
7 lead materials, detailed engineering and design activities, and topographical and
8 subsurface verification through lidar surveys and geotechnical studies. The preferred route
9 for the Project has been established and the Final ESR and Statement of Completion have
10 been filed with the MECP. The real estate component of the cost estimate has been
11 informed by a number of site-specific appraisals finalized to date, as further described in
12 **Exhibit E, Tab 1, Schedule 1** and Hydro One has achieved voluntary early access
13 agreements for 98% of the properties affected by the corridor.

14
15 The Project cost estimate for the transmission line is based on a fixed price EPC contract
16 with the selection of the EPC contractor using a two-stage process (known as the ECI-
17 EPC methodology)⁸. The first stage was to utilize an external owners engineer to qualify
18 EPC bidders, based on experience and capacity, and to perform many of the development
19 functions that under the standard Hydro One EPC delivery model would be performed
20 internally by Hydro One. During the second stage, EPC contractors developed
21 independent competitive proposals. This process allowed the EPC contractors to advance
22 and optimize line design, obtain competitive market pricing from their suppliers and
23 vendors and to identify and evaluate engineering, procurement and construction risks and
24 opportunities during the development of their offers. Thus, the cost estimate reflects
25 current market-tested EPC pricing to deliver the Project. Hydro One has entered into an
26 agreement with the selected EPC contractor for the transmission line and has commenced

⁶ An estimate range of -20%/+30%

⁷ As per 96r-18 Cost Estimate Classification System – EPC Power Transmission Line Infrastructure Industries recommended practice document.

⁸ For detailed explanation of the ECI-EPC methodology and supporting third party analysis by Atrium refer to EB-2023-0198 Exhibit B, Tab 7, Schedule 1 and Attachment 1 of the same Schedule.

1 early activities to advance the contractors' long lead procurement process, as well as the
2 engineering and permitting program.

3
4 The Project cost estimate for the station work at Clarington TS was also based on a fixed
5 price EPC contract; however, the selection of the EPC contractor was based on Hydro
6 One's standard RFP bid process. Conversely, the Project cost estimate for the station
7 work at Dobbin TS, which will be undertaken by Hydro One construction, was developed
8 using a multi-faceted approach involving internal cost estimate tools and techniques, and
9 a risk management model for the contingency allowance.

10 11 **1.0 RISKS AND CONTINGENCIES**

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

17
18 The Project risks that predominantly contribute to the total contingency suggested for this
19 Project include the following:

- 20 • **Approvals, Permits and Authorizations:** Risk of delays or cost escalation in
21 obtaining required approvals and necessary permits including leave to construct, and
22 all necessary land rights (e.g., should property owners refuse Hydro One's voluntary
23 agreements leading to the need to seek authority to expropriate) that may cause delay
24 or disruption to the construction schedule and additional cost.
- 25 • **Outage Constraints:** There is a risk of securing required transmission system
26 outages due to system instability, weather or environmental reasons, insufficient
27 generation, competing transmission system outages in the area, or critical load
28 requirements. Time-of-year can also dictate the outages schedule and potential for
29 cancellations. Outage delays or cancellations may cause schedule disruptions and
30 increased costs.

- 1 • **Subsurface Conditions:** Risk that the actual subsurface or environmental conditions
2 are different from the ones determined through preliminary studies (e.g., if
3 archaeological assessments determine potential for significant archaeological sites on
4 the route, or identification of underground obstructions and/or unsuitable/unexpected
5 soil conditions) that may require additional mitigations which would have a cost impact
6 and could delay or stop the Project's progress.

7
8 To mitigate these risks Hydro One has:

- 9 1. Proactively submitted all regulatory applications, permits and authorizations well
10 in advance of the construction start of the Project, including the Final ESR with the
11 MECP and this leave to construct application. Hydro One also initiated early
12 engagement with impacted landowners in the development of the Project and
13 produced a project-specific principles-based acquisition program to govern
14 positive discussions and promote voluntary land right settlements.
- 15 2. Factored outage planning into the initial planning and scheduling phase of the
16 Project to develop an outage sequencing plan with input from Hydro One System
17 Operations and the IESO to establish outage dates for critical activities.
- 18 3. Performed preliminary studies and testing to identify subsurface conditions to
19 develop implementation plans to address the risk if encountered during
20 construction, as well as prioritized archaeological assessment areas on the route
21 that have a higher risk of being sites of significant archaeological potential.

22
23 Cost contingencies that have not been included in the total contingency suggested for this
24 Project, due to the unlikelihood or uncertainty of occurrence, include:

- 25 • Labour disputes;
- 26 • Safety or environmental incidents;
- 27 • Significant changes in costs and/or availability of materials and equipment beyond
28 Hydro One's control, including impacts from changes in government policy, the
29 introduction of new tariffs in addition to those already in effect, or disruptions arising
30 from geopolitical instability; and
- 31 • 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 other recent comparable projects.

- **Woodstock Area Transmission Reinforcement:** Upgrade of an existing 115 kV double-circuit transmission line (W7W/W12W) to construct a new 230 kV double-circuit transmission line between Ingersoll and Woodstock (approximately 13.6 km) to address capacity needs in the Woodstock area. The new 230 kV double-circuit transmission line was connected to the existing 230 kV double-circuit transmission line (M32W/M33W) at Ingersoll TS and replaced approximately 12 km of the existing 115 kV ROW from Ingersoll TS to the new Karn TS and extended from Karn TS to Woodstock TS along the existing ROW. Leave to construct approval for this project was provided under OEB docket EB-2007-0027.
- **Power South Nepean Project:** Upgrade of an existing 115 kV single-circuit transmission line to construct a new 230 kV double-circuit transmission line (approximately 12.2 km) to address capacity needs in the South Nepean area of Ottawa. The new 230 kV double-circuit transmission line replaced approximately 10.9 km of the existing 115 kV single-circuit transmission line (S7M) from West Hunt Club Road to Cambrian Road and extended an additional approximate 1.3 km from Cambrian Road to the new MTS. Leave to construct approval for this project was provided under OEB docket EB-2019-0077
- **Chatham by Lakeshore Transmission Line:** Construction of an approximately 49 km new 230 kV double-circuit transmission line from Chatham SS to Lakeshore TS to increase the transmission capability to the Windsor-Essex area. The 230 kV double-circuit transmission line was built on a combination of a new corridor and approximately 16 km of widened existing idle 115 kV transmission corridor (K6Z) between Chatham and Tilbury. Leave to construct approval for this project was provided under OEB docket EB-2022-0140.

1 These projects were selected as reasonable comparables because they are all 230 kV
2 double-circuit transmission lines utilizing predominantly lattice steel towers and included
3 a rebuild of an existing 115 kV transmission corridor. Additionally, the Woodstock Area
4 Transmission Reinforcement and Chatham by Lakeshore Transmission Line projects
5 were selected as reasonable comparable projects because they were projects utilizing the
6 same sized 1443.7 kcmil ACSR/TW conductor as contemplated for the DKPL Project.

7
8 For the purposes of the comparison, Hydro One has excluded costs associated with real
9 estate. As well, adjustments were also applied to account for technical and execution-
10 related differences between the projects (e.g., temporary bypass arrangements, variations
11 in foundation / conductor / structure types, skywire upgrades, circuit reconfigurations,
12 underground line sections), as well as to reflect the impact of newly enacted tariffs.

13
14 Hydro One has excluded the real estate costs from all comparable projects because these
15 are project-specific requirements and not directly comparable across projects. Although
16 real estate costs are excluded from the comparison provided in Table 3, the costs are
17 reasonable as the real estate estimate for the DKPL Project is supported by third party
18 appraisals, agriculture expert analysis of commodity prices and a contingency amount that
19 is reserved for potential expropriation.

20
21 Further adjustments were made for regional topography that would impact construction,
22 notably the use of micropile foundations based on terrain characteristics along the corridor
23 on the Power South Nepean Project. In addition, an adjustment was made for the use of
24 a temporary line bypass required for the project-specific construction execution plans for
25 the Woodstock Area Transmission Reinforcement and Power South Nepean projects due
26 to load/outage constraints. Similarly, adjustments were made for variations in the
27 conductor and structure types used for the comparator projects, specifically an adjustment
28 for the incremental cost of steel pole structures utilized along sections of the Woodstock
29 Area Transmission Reinforcement and Power South Nepean projects route, and the
30 incremental cost between the 997.2 kcmil ACSR/TW conductor utilized for the Power
31 South Nepean project relative to of the larger ampacity conductor (i.e., 1443.7 kcmil

1 ACSR/TW) required for the Woodstock Area Transmission Reinforcement, Chatham by
2 Lakeshore Transmission Line, and DKPL projects.

3
4 Hydro One also adjusted the DKPL Project costs to reflect the additional project-specific
5 scope requirements relative to the comparable projects associated with terminating the
6 proposed transmission line at Dobbin TS. Specifically, the reconfiguration of the line entry
7 of three existing 230 kV transmission lines to create sufficient space for the new
8 transmission lines entry into the station and required upgrades to the skywire on the
9 existing 230 kV transmission line (Circuit X1P) emanating out of Dobbin TS to address
10 increased fault levels from the addition of the new transmission line. Further, an
11 adjustment was made to account for a short segment of underground line required for the
12 DKPL Project to avoid clearance limitation constraints associated with crossing over four
13 existing 230 kV transmission lines near Clarington. These elements are unique to the
14 DKPL Project and not comparable to the other projects.

15
16 Additionally, an adjustment was made to the DKPL Project to account for incremental
17 costs associated with new tariffs effective December 26, 2025, whereby the Government
18 of Canada imposed a 25% tariff on imported steel derivative products, including tower
19 steel structures, conductors and tower foundation steel materials.⁹

20
21 The variances in the unadjusted per/km cost to execute these projects is driven by the
22 timing differences in the in-service date. Therefore, Table 3 has been adjusted to show
23 comparable projects in 2029 dollars utilizing inflation values for future years consistent
24 with the inflation parameters provided by the OEB.

25
26 When considering the adjusted comparable cost per km ratio for all other transmission line
27 costs in Table 3, the comparable projects demonstrate that the estimate for the Project is
28 consistent with the cost to complete comparable transmission line works and is
29 reasonable.

⁹ [Government of Canada's List of steel derivative products subject to 25% tariffs effective December 26, 2025](#)

1

Table 3 - Costs of Comparable Line Projects

Project	Woodstock Area Reinforcement (Line Cost)	Power South Nepean Project (Line Cost)	Chatham x Lakeshore Transmission Line (Line Cost)	Durham Kawartha Power Line (Line Cost)
Circuit Operating Designation(s)	M32W/M31W plus K12/K7	S7M and E34M	C87H and C88H	T40P and T41P
Voltage	230 kV	230 kV	230 kV	230 kV
Structure Type	Steel Lattice and Steel Pole	Steel Lattice and Steel Pole	Steel Lattice	Steel Lattice
Single or Double Circuit	Double	Double	Double	Double
Conductor	1443.7 kcmil ACSR/TW	997.2 kcmil ACSR/TW	1443.7 kcmil ACSR/TW	1443.7 kcmil ACSR/TW
Location	Southwest Ontario	Eastern Ontario	Southwest Ontario	Eastern Ontario
Project Surroundings	Urban/Rural	Urban/Rural	Mostly Rural	Urban/Rural
In-Service Year	2012	2021	2024	2029
Estimate or Actual	Actual	Actual	Actual	Estimate
OEB-Approved Cost Estimate	\$42.9M ¹⁰	\$58.8M ¹¹	\$235.3M ¹²	–
Total Cost	\$35,600K	\$51,276K	\$208,280K	\$335,207K
Less Adjustments:				
<i>Real Estate</i>	\$500K	\$2,229K	\$73,619K	\$78,174K ¹³
<i>Temporary Bypass</i>	\$4,300K	\$1,419K	N/A	N/A
<i>Micropile Foundation</i>	N/A	\$6,730K	N/A	N/A
<i>Incremental Conductor Cost</i>	N/A	(\$168K)	N/A	N/A
<i>Incremental Steel Pole Cost</i>	\$466K	\$2,192K	N/A	N/A
<i>Circuit Reconfigurations</i>	N/A	N/A	N/A	\$4,814K ¹⁴
<i>X1P Skywire Upgrade</i>	N/A	N/A	N/A	\$2,410K ¹⁵
<i>Underground Line</i>	N/A	N/A	N/A	\$17,126K ¹⁶
<i>Newly Enacted Tariff Impact</i>	N/A	N/A	N/A	\$4,968K
Comparable Costs, before Escalation	\$30,334K	\$38,874K	\$134,661K	\$227,715K
Escalation Adjustment¹⁷	\$18,768K	\$13,088K	\$25,944K	N/A
Total Adjusted Comparable Cost	\$49,102K	\$51,962K	\$160,605K	\$227,715K
Approximate Length	13.6 km	12.2 km	49 km	55 km
Unit Cost	\$3,610/km	\$4,259K/km	\$3,278K/km	\$4,140K/km

¹⁰ As per Section 92 leave to construct proceeding EB-2007-0027.

¹¹ As per Section 92 leave to construct proceeding EB-2019-0077.

¹² As per Section 92 leave to construct proceeding EB-2022-0140.

¹³ This amount includes the direct real estate costs of \$56,925K plus contingency carried for expropriation, interest and overhead.

¹⁴ Cost to reconfigure the existing 230 kV transmission lines (Circuits P15C, X1P and C27P) at Dobbin TS to create sufficient space to build the new diameter required for connection of the proposed transmission line. This amount includes the direct costs plus interest, overhead, and contingency.

¹⁵ Cost to upgrade the skywire on the existing 230 kV transmission line (Circuit X1P) emanating out of Dobbin TS to address increased fault levels from the addition of the proposed transmission line. This amount includes the direct costs plus interest, overhead, and contingency.

¹⁶ Cost to construct the short underground section near Clarington to avoid crossing four existing 230 kV transmission lines. This amount includes the direct costs plus interest, overhead, and contingency.

¹⁷ Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.

3.0 COSTS OF COMPARABLE PROJECTS – STATIONS

For station cost comparison purposes, Table 4 below shows the cost, construction, and technical comparisons of the proposed terminal station modifications at Dobbin TS and Clarington TS to the completed station work at Wawa TS and Lakehead TS undertaken for the East West Tie project, and the completed station work at Chatham SS undertaken for the Chatham by Lakeshore Transmission Line project, respectively.

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.

With acknowledgement to these limitations, the comparable projects selected are considered reasonable because the scope of work is materially similar when compared to other 230 kV line terminal station modification projects (i.e., all involve the installation of a new diameter, 230 kV circuit breakers, 230 kV disconnect switches, etc.) as documented in Table 4. The projects were also executed in predominantly rural environments with comparable constructability and permitting conditions.

For the purposes of comparison in Table 4, Hydro One has adjusted the comparable projects to exclude the the cost of real estate required for Wawa TS and Lakehead TS and the addition of new relay buildings at Chatham SS, Wawa TS, and Lakehead TS as these are project-specific requirements and not comparable to Dobbin TS and Clarington TS where PCT modifications are required within existing buildings, and all new facilities will be built on Hydro One's existing owned property.

An adjustment was also made to Lakehead TS to exclude the cost of the new shunt reactor, capacitor bank and associated equipment, which were required to ensure sufficient level of reactive support with the addition of the new transmission lines. This requirement was project-specific and not comparable across all projects.

1 Adjustments were also made to the Dobbin TS and Clarington TS cost estimates to
2 exclude the protection upgrades at remote stations as this is a project-specific
3 requirement, and to exclude the incremental cost of the tariffs on imported steel products
4 that was newly enacted by the Government of Canada.

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

9
10 When considering the adjusted comparable station costs in Table 4, it should be noted
11 that the scope of work at Dobbin TS exceeds that of the comparable projects and, as such,
12 results in slightly higher costs. As previously noted, the unique site conditions and station
13 configuration make individual station cost component comparisons difficult. While Hydro
14 One has not undertaken projects of identical size and scope to enable a direct
15 comparison, the available recent comparator projects nevertheless support the conclusion
16 that the estimated costs for the terminal station modifications at Dobbin TS and Clarington
17 TS are consistent with those for comparable work and are therefore reasonable.

1

Table 4 - Costs of Comparable Station Projects

Project	Chatham SS (CxL Project)	Wawa TS (EWT Project)	Lakehead TS (EWT Project)	Dobbin TS (DKPL Project)	Clarington TS (DKPL Project)
Technical	Add one new diameter, (3) 230 kV circuit breakers, (8) switches, new relay building	Add two new diameters, (6) 230 kV circuit breakers, (14) switches, new relay building	Add one new diameter, (5) 230 kV circuit breakers, (16) switches, (1) shunt reactor and capacitor bank, new relay building	Add one new diameter, (3) 230 kV circuit breakers, (11) switches; replace (5) 230 kV circuit breakers & (10) switches; PCT modifications	Add one new diameter, (2) 230 kV circuit breakers, (5) switches; relocate existing capacitor bank; PCT modifications
Location	Southwest Ontario	Northern Ontario	Northern Ontario	Eastern Ontario	Eastern Ontario
Project Surroundings	Mostly Rural	Rural	Rural	Rural	Rural
In-Service Year	2024	2022	2022	2029	2029
Estimate or Actual	Actual	Actual	Actual	Estimate	Estimate
OEB-Approved Cost Estimate	\$28.8M ¹⁸	\$44.8M ¹⁹	\$50.9M ²⁰	-	-
Total Cost	\$28,788K	\$51,700K	\$57,700K	\$68,823K	\$24,134K
Less Adjustments:					
<i>Real Estate</i>	N/A	\$169K	\$4K	N/A	N/A
<i>Relay Building</i>	\$3,634K	\$8,972K	\$4,339K	N/A	N/A
<i>Reactor and Capacitor Bank</i>	N/A	N/A	\$3,649K	N/A	NA
<i>Remote Station Work</i>	N/A	N/A	N/A	\$420K	\$140K
<i>Newly Enacted Tariff Impacts</i>	N/A	N/A	N/A	\$861K	\$682K
Comparable Costs, before Escalation	\$25,154K	\$42,559K	\$49,708K	\$67,542K	\$23,312K
Escalation Adjustment²¹	\$4,846K	\$13,888K	\$16,220K	N/A	N/A
Total Adjusted Comparable Cost	\$30,000K	\$56,447K	\$65,928K	\$67,542K	\$23,312K

¹⁸ As per Section 92 leave to construct proceeding EB-2022-0140.

¹⁹ As per Section 92 leave to construct proceeding EB-2017-0194.

²⁰ As per Section 92 leave to construct proceeding EB-2017-0194.

²¹ Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.

1 **CONNECTION PROJECTS REQUIRING NETWORK REINFORCEMENT**

2

3 This is not a connection project. Facilities being constructed as part of this Project are
4 limited to those discussed in the details of the work being undertaken in **Exhibit C, Tab**
5 **1, Schedule 1.**

Filed: 2026-06-12
EB-2026-0155
Exhibit B
Tab 8
Schedule 1
Page 2 of 2

1

This page has been left blank intentionally.

TRANSMISSION RATE IMPACT ASSESSMENT

1.0 ECONOMIC FEASIBILITY

The Project costs will be included in the network pool 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 \$433.3 million¹, plus the assumed impact on the future capital cost allowance, Hydro One's corporate income tax and approximately \$13.0 million in annual incremental network revenue utilizing the 2026 UTR over a 25-year evaluation period, the Project will have a negative net present value of \$254.7 million as seen in Tables 1 and 2 below.

2.0 COST RESPONSIBILITY

Network Pool

The proposed Project will establish a new 230 kV transmission line connection between Dobbin TS and Clarington TS to address the long-term capacity needs and support the reliable supply and secure operation of the bulk system serving the Peterborough to Quinte West and Ottawa regions. The Project is not associated with any specific load increase or customer load application. As identified by the IESO bulk report², there is a need to:

- Increase the overall transfer capability of the bulk transmission system to ensure a load meeting capability of 440 MW;
- Ensure sufficient supply capacity to address the forecast load in the Peterborough to Quinte West region and surrounding area and provide flexibility and resiliency in meeting future changes in demand; and

¹ Initial network costs of \$433.3 million include \$428.2 million of up-front capital costs plus \$5.1 million cost of removals

² Exhibit H, Tab 1, Schedule 1, Attachment 1.

- Mitigate upstream thermal constraints limiting flows into the Ottawa region.

Both Dobbin TS and Clarington TS are existing network stations, hence the new 230 kV transmission line is to be included in the Network Pool as it directly connects these network stations and addresses the above stated IESO-identified system needs. No customer capital contribution is required, consistent with the provisions of Section 6.3.5 of the TSC.

3.0 RATE IMPACT ASSESSMENT

The analysis of the 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 Uniform Transmission Rate Schedules. The Network pool revenue requirements would be affected by the Project based on the project cost allocation.

Network Pool

Based on the estimated initial cost of \$433.3 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 the transmission rate base at the projected in-service date of December 30, 2029. Over a 25-year time horizon, the 2026 OEB-approved rate of \$6.39 per kW/month increases to \$6.44 per kW/month in the 1st year, then increases further to \$6.48 per kW/month between the 2nd and 16th year, then decreases to \$6.47 per kW/month in the 17th year and then decreases further to \$6.46 per kW/month in the 23rd year. The detailed analysis illustrating the calculation of the incremental network revenue and rate impact is provided in Tables 3 and 4 below.

Impact on Typical Residential Customer

Based on the load forecast, initial capital costs and ongoing maintenance costs, adding the costs of the required facilities to the network pool will cause a \$0.15 per month increase in 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.

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	0.00%
G. Impact on Transformation Connection Pool Provincial Uniform Rates	0.00%
H. Impact on Network Connection Pool Provincial Uniform Rates	1.41%
I. Increase in Transmission costs for typical monthly bill (C x F + D x G + E x H)	\$0.15 per month or \$1.78 per year
J. Net increase on typical residential customer bill (I / A)	0.09%

2

Table 1 - Net Present Value, Network Pool page 1

Date: 5-May-26		SUMMARY OF CONTRIBUTION CALCULATIONS											
Project #		Network Pool - Estimated cost											
Facility Name:		Durham Kawartha Power Line											
Description:		Durham Kawartha Power Line											
Customer:													
		In-Service Date <----- Project year ended - annualized from In-Service Date -----> Month Year Dec-30 Dec-30 Dec-30 Dec-30 Dec-30 Dec-30 Dec-30 Dec-30 Dec-30 Dec-30 Dec-30 Dec-30 Dec-30 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)		170.0											
Load adjustments (MW)		0.0											
Tariff Applied (\$/kW/Month)		170.0											
Incremental Revenue - \$M		6.39											
Removal Costs - \$M		(5.1)											
On-going OM&A Costs - \$M		0.0											
Municipal Tax - \$M		(1.4)											
Net Revenue/(Costs) before taxes - \$M		(5.1)											
Income Taxes		1.4											
Operating Cash Flow (after taxes) - \$M		(3.6)											
Cumulative PV @ 5.65%		171.1											
PV Operating Cash Flow (after taxes) - \$M (A)		(3.8)											
Capital Expenditures - \$M													
Upfront - capital cost before overheads & AFUDC		(385.1)											
- Overheads		(11.2)											
- AFUDC		(31.9)											
Total upfront capital expenditures		(428.2)											
On-going capital expenditures		0.0											
PV On-going capital expenditures		0.0											
Total capital expenditures - \$M		(428.2)											
Capital Expenditures - \$M													
PV CCA Residual Tax Shield - \$M		2.4											
PV Working Capital - \$M		(0.0)											
PV Capital (after taxes) - \$M (B)		(425.8)											
Cumulative PV Cash Flow (after taxes) - \$M (A) + (B)		(254.7)											

Discounted Cash Flow Summary

Economic Study Horizon - Years:

25

Discount Rate - %

5.65%

\$M

PV Incremental Revenue

177.2

PV OM&A Costs

(9.9)

PV Municipal Tax

(19.1)

PV Income Taxes

(39.3)

PV CCA Tax Shield

64.6

PV Capital - Upfront

(428.2)

Add: PV Capital Contribution

0.0

PV Capital - On-going

0.0

PV Working Capital

(0.0)

PV Surplus / (Shortfall)

(254.7)

Profitability Index*

0.4

Other Assumptions

In-Service Date:

30-Dec-29

Payback Year:

2054

No. of years required for payback:

25

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

1

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

Date: 5-May-26		SUMMARY OF CONTRIBUTION CALCULATIONS													
Project #		Network Pool - Estimated cost													
Facility Name:		Durham Kavartha Power Line													
Description:		Durham Kavartha Power Line													
Customer:															
		Project year ended - annualized from In-Service Date													
Month		Dec-30	Dec-30	Dec-30	Dec-30	Dec-30	Dec-30	Dec-30	Dec-30	Dec-30	Dec-30	Dec-30	Dec-30	Dec-30	Dec-30
Year		2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2054
		13	14	15	16	17	18	19	20	21	22	23	24	25	25
Revenue & Expense Forecast															
Load Forecast (MW)		170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
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	0.0
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	6.39
Incremental Revenue - \$M		13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Removal Costs - \$M															
On-going OM&A Costs - \$M		(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Municipal Tax - \$M		(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)
Net Revenue/(Costs) before taxes - \$M		11.3	11.3	11.3	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
Income Taxes		0.4	0.2	(0.1)	(0.3)	(0.5)	(0.7)	(0.8)	(1.0)	(1.2)	(1.3)	(1.4)	(1.5)	(1.5)	(1.6)
Operating Cash Flow (after taxes) - \$M		11.7	11.5	11.2	11.0	10.7	10.6	10.4	10.2	10.1	9.9	9.8	9.7	9.6	9.6
PV Operating Cash Flow (after taxes) - \$M (A)		5.9	5.4	5.0	4.7	4.3	4.0	3.8	3.5	3.3	3.0	2.8	2.7	2.5	2.5
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	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)		(299.8)	(294.4)	(289.3)	(284.6)	(280.3)	(276.3)	(272.5)	(269.0)	(265.8)	(262.7)	(259.9)	(257.2)	(254.7)	(254.7)

Revenue Requirement and Network Pool Rate Impact		(Before Capital Contribution)
Revenue requirement	100.00	100.00
Network pool rate impact	100.00	100.00
Total	200.00	200.00

Durham Kawartha Power Line		Project YE											
		30-Dec 2030	30-Dec 2031	30-Dec 2032	30-Dec 2033	30-Dec 2034	30-Dec 2035	30-Dec 2036	30-Dec 2037	30-Dec 2038	30-Dec 2039	30-Dec 2040	30-Dec 2041
Calculation of Incremental Revenue Requirement (\$ millions)		1	2	3	4	5	6	7	8	9	10	11	12
In-service date	30-Dec-29												
Capital Cost	428.2												
Less: Capital Contribution Required	-												
Net Project Capital Cost	428.2												
Average Rate Base		209.8	415.3	406.8	398.2	389.7	381.2	372.6	364.1	355.5	347.0	338.4	329.9
Incremental OM&A Costs		0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Grants in Lieu of Municipal tax		1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Depreciation		8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Interest and Return on Rate Base		13.3	26.3	25.8	25.3	24.7	24.2	23.6	23.1	22.6	22.0	21.5	20.9
Income Tax Provision		0.1	(2.6)	(1.8)	(1.1)	(0.5)	0.1	0.6	1.0	1.5	1.8	2.2	2.5
REVENUE REQUIREMENT PRE-TAX		23.6	34.0	34.2	34.4	34.5	34.6	34.5	34.5	34.3	34.2	34.0	33.7
Incremental Revenue		13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
SUFFICIENCY/(DEFICIENCY)		(10.6)	(21.0)	(21.2)	(21.3)	(21.4)	(21.5)	(21.5)	(21.4)	(21.3)	(21.1)	(20.9)	(20.7)
Network Pool Revenue Requirement including sufficiency/(deficiency)	Base Year 1,495	1,518	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,528
Network MW	234	236	236	236	236	236	236	236	236	236	236	236	236
Network Pool Rate (\$/kw/month)	6.39	6.44	6.48	6.48	6.48	6.48	6.48	6.48	6.48	6.48	6.48	6.48	6.48
Increase/(Decrease) in Network Pool Rate (\$/kw/month), relative to base year		0.05	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
RATE IMPACT relative to base year		0.78%	1.41%	1.41%	1.41%	1.41%	1.41%	1.41%	1.41%	1.41%	1.41%	1.41%	1.41%
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%	86.9% Class 47 assets except for Land											

Table 4 - Revenue Requirement and Network Pool Rate Impact, page 2

Revenue Requirement and Network Pool Rate Impact							(Before Capital Contribution)							
Durham Kawartha Power Line		30-Dec	30-Dec	30-Dec	30-Dec	30-Dec	30-Dec	30-Dec	30-Dec	30-Dec	30-Dec	30-Dec	30-Dec	30-Dec
Calculation of Incremental Revenue Requirement (\$ millions)		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
In-service date	30-Dec-29													
Capital Cost	428.2													
Less: Capital Contribution Required	-													
Net Project Capital Cost	428.2													
Average Rate Base		321.3	312.8	304.2	295.7	287.1	278.6	270.0	261.5	252.9	244.4	235.8	227.3	218.7
Incremental OM&A Costs		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Grants in Lieu of Municipal tax		1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Depreciation		8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Interest and Return on Rate Base		20.4	19.8	19.3	18.8	18.2	17.7	17.1	16.6	16.0	15.5	15.0	14.4	13.9
Income Tax Provision		2.7	3.0	3.2	3.4	3.6	3.7	3.8	3.9	4.0	4.1	4.1	4.2	4.2
REVENUE REQUIREMENT PRE-TAX		33.5	33.2	32.8	32.5	32.1	31.7	31.3	30.9	30.4	30.0	29.5	29.0	28.5
Incremental Revenue		13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
SUFFICIENCY/(DEFICIENCY)		(20.4)	(20.1)	(19.8)	(19.5)	(19.1)	(18.7)	(18.3)	(17.8)	(17.4)	(16.9)	(16.4)	(15.9)	(15.4)
Network Pool Revenue Requirement including sufficiency/(deficiency)	Base Year 1,495	1,528	1,528	1,528	1,527	1,527	1,527	1,526	1,526	1,525	1,525	1,524	1,524	1,523
Network MW	234	236	236	236	236	236	236	236	236	236	236	236	236	236
Network Pool Rate (\$/kw/month)	6.39	6.48	6.48	6.48	6.48	6.47	6.47	6.47	6.47	6.47	6.47	6.46	6.46	6.46
Increase/(Decrease) in Network Pool Rate (\$/kw/month), relative to base year		0.09	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.07
RATE IMPACT relative to base year		1.41%	1.41%	1.41%	1.41%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.10%	1.10%	1.10%

Table 5 - 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 need for the Project was not identified in the TSP submitted as part of Hydro One's most recent 2023 to 2027 transmission revenue requirement application.¹ The Project is a result of an emergent bulk system need that was subsequently recognized through the East Ontario bulk planning process. The East Ontario bulk planning process commenced with an initial public engagement session on April 14, 2022, and concluded with the release of the East Ontario bulk plan report titled "*Gatineau Corridor End-of-Life Study*" in December 2022.² The IESO formally recommended the need for the Project in this bulk plan report, which is provided in **Exhibit H, Tab 1, Schedule 1, Attachment 1**. The IESO's final recommendation and report, as well as the subsequent Orders in Council³ declaring that construction of the Project is needed occurred after Hydro One's most recent revenue requirement application had concluded.

Detailed information regarding the Project's capital expenditures and in-service rate base additions for the terminal station modification work at Dobbin TS and Clarington TS (as outlined in Table 2 of **Exhibit B, Tab 7, Schedule 1**) will be provided in Hydro One's upcoming transmission rate application for the 2028 to 2032 period. Conversely, the Project's new transmission line is expected to be owned by, and included in, the rate base of a new future transmission partnership licenced by the OEB. As of the date of this Application, the new partnership has not yet been finalized. As such, the transmission line project costs (as outlined in Table 1 of **Exhibit B, Tab 7, Schedule 1**) will be tracked in Hydro One's OEB-approved ATP regulatory account. Hydro One notified the OEB on November 21, 2023⁴, of the inclusion of the DKPL Project in the ATP regulatory account in accordance with the OEB's direction in the ATP regulatory account Decision and Order.⁵

¹ EB-2021-0110, OEB Decision and Order (November 29, 2022).

² [IESO's East Ontario Bulk Planning - Gatineau Corridor End-Of-Life Study engagement](#).

³ Orders in Council, O.C. 1531/2023 and O.C. 1532/2023 (October 19, 2023).

⁴ EB-2023-0319, HONI's Letter to OEB - Notification of Intention to Use the Regulatory Account for Three New Affiliate Transmission Line Projects (November 21, 2023).

⁵ EB-2021-0169, OEB Decision and Order (October 7, 2021).

1 **DEFERRAL ACCOUNT REQUEST INFORMATION**

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

1

PROJECT SCHEDULE

TASK	START	FINISH
Section 92 Approval	Jun-2026	Jan-2027
LINES¹		
Receipt of Other Key Permits and Approvals	Jun-2024	Jan-2027
Voluntary Property Rights Acquisition ²	Nov-2025	Mar-2027
Detailed Engineering	Mar-2026 ³	Mar-2027
Procurement	Jun-2026	Dec-2027
Construction	Mar-2027	Jul-2029
Commissioning	Oct-2028	Nov-2029
In Service	N/A	Dec-2029
Site Remediation	Jul-2029	May-2030
STATIONS⁴		
Receipt of Other Key Permits and Approvals	Jun-2024	Jan-2027
Detailed Engineering	Jan-2026	Dec-2026
Procurement	Jul-2025	Jun-2027
Construction	Feb-2027	Sep-2029
Commissioning	Aug-2027	Nov-2029
In Service	N/A	Dec-2029
Site Remediation	Oct-2029	May-2030

¹ The proposed lines schedule reflects the key milestones for both the construction of the proposed transmission line and the skywire upgrades required on existing transmission line (Circuit X1P).

² 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.

³ Based on the conceptual engineering and design work that commenced in 2024.

⁴ The proposed stations schedule reflects the key milestones for the terminal station modifications at Clarington TS and Dobbin TS and the protection modifications required at four remote stations.

1 The table above outlines the forecast schedule for the Project and has been predicated
2 on Hydro One successfully securing leave to construct approval by January 2027, and
3 voluntary land right agreements by March 2027. Station construction is set to commence
4 in February 2027, followed by line construction in March 2027. The cost evidence provided
5 in **Exhibit B, Tab 7, Schedule 1** is underpinned by this schedule. If Hydro One is
6 unsuccessful in securing voluntary agreements required along the ROW, within a short
7 period following leave to construct approval, Hydro One intends to seek expropriation
8 authority from the OEB in accordance with section 99 of the *OEB Act, 1998*. As identified
9 in **Exhibit B, Tab 7, Schedule 1**, delays in regulatory approvals beyond those
10 contemplated in the project schedule documented above could materially impact the cost
11 of the Project. Contingency has been carried on the Project to account for minor deviations
12 to this schedule, however, material delays in securing approvals could have significant
13 impacts that have not been carried in contingency. Project timelines have been based on
14 recent OEB processing timelines and take into consideration the OEB's Performance
15 Standards for Processing Leave to Construct Applications.

DESCRIPTIONS OF THE PHYSICAL DESIGN

1.0 ROUTE DESCRIPTION

The proposed 230 kV double-circuit transmission line will be located in Eastern Ontario, passing through the townships of Selwin, Cavan-Monaghan, and Scugog; the City of Kawartha Lakes; and the Municipality of Clarington. The transmission line will run between two existing Hydro One stations, Dobbin TS and Clarington TS, with an overall length of approximately 55 km and ROW width between 30 m to 46 m. Approximately 95% of the proposed transmission line will be located within existing transmission corridors, and the remaining 5% will be located along a new transmission corridor.

1.1 ROUTE DETAILS

- i. The Project route starts at Dobbin TS in the Township of Selwin located in the County of Peterborough. From the station, the route runs southwest for approximately 45 km towards Burketon Station on a 30 m ROW located within an existing transmission corridor. The initial section (approximately 6 km) will be located between Circuit P15C to the north and Circuits P3S/P4S to the south, whereas the latter section (approximately 39 km) will run parallel to Circuit P15C on the south side.
- ii. At Burketon Station, the route deviates south of Circuit P15C continuing along an existing transmission corridor for approximately 4 km until just west of Enfield Road. This 4 km section of the route will utilize a 46 m ROW.
- iii. At this point, the route turns 90 degrees and runs southerly along a new 46 m ROW for approximately 2.5 km until reaching Regional Road 3.
- iv. At Regional Road 3, the route continues south underground for 400 m until Langmaid Road, due to overhead clearance concerns with crossing over four existing 230kV circuits (Circuits T31H, T32H, T33E, and T22C) in the area.
- v. At Langmaid Road, the route turns 90 degrees and runs west for approximately 1 km on a new 46 m ROW parallel to the four existing 230 kV circuits.
- vi. At this point, the route turns 90 degrees and runs southerly parallel to the four existing 230 kV circuits for another 1 km along Hydro One owned lands before

entering the north side of Clarington TS, located in the Municipality of Clarington.

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 proposed 230 kV transmission line will have two (2) circuits, comprised of one 1443.7 kcmil ACSR/TW “Superior” conductor per phase, and two (2) OPGW shieldwires (i.e., one per circuit), primarily supported on self-supporting lattice towers. Further, the transmission line will have the following attributes:

- i. The line will have a continuous ampacity of 1145 A (summer rating at 35°C);
- ii. Glass insulators will be used for both suspension and tension applications in accordance with Hydro One standards;
- iii. Stockbridge-type vibration dampers will be used on both the line conductors and the OPGW shieldwires, in accordance with Hydro One standards. The placement of all dampers will be based on the final line configuration and per manufacturer's design;
- iv. The structures will be supported by either helical pile type or concrete drilled caissons foundations. The foundation type will be selected based on site-specific geotechnical conditions and the tower design;
- v. The line will make use of a total of 180 transmission line towers; including 165 self-supported lattice suspension towers with nominal spans of 320 m (refer to Figure 1), and 15 dead-end/angle tower structures (refer to Figure 2); and
- vi. Approximately 400 m of 230 kV-rated XLPE underground cables and associated components, including concrete-encased duct banks, splice chambers, grounding systems, and thermal backfill. To facilitate the connection between the overhead conductor and underground cable, transition termination structures (refer to Figure 3) will be installed on either side of Regional Road 3.

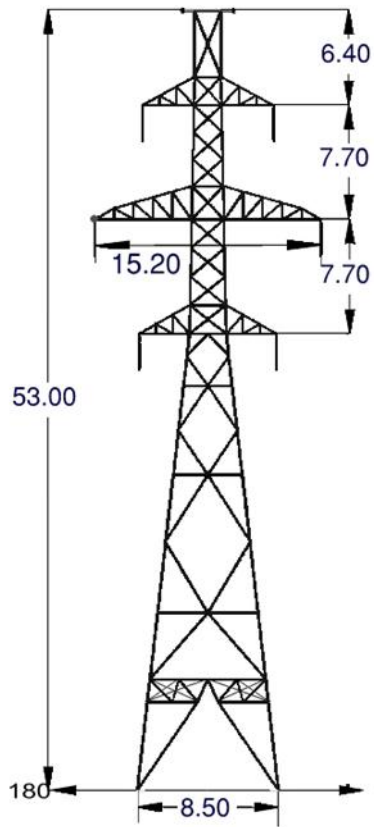


Figure 1: Suspension Tower Structure

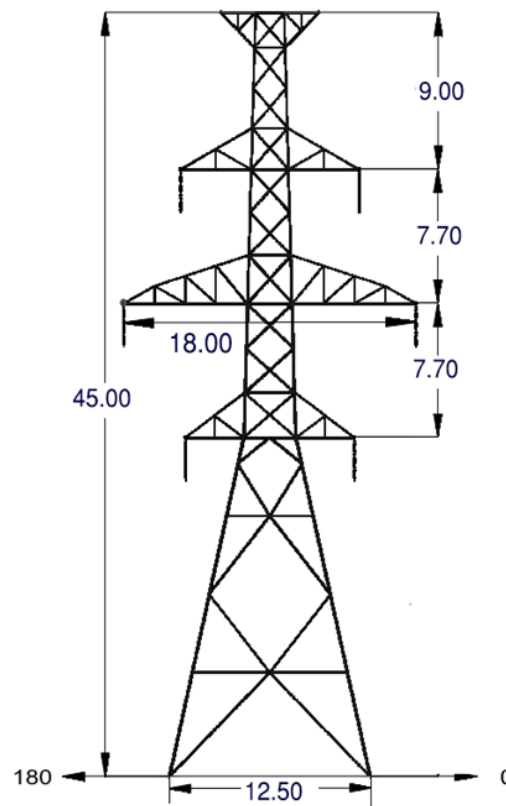


Figure 2: Dead-end/Angle Tower Structure

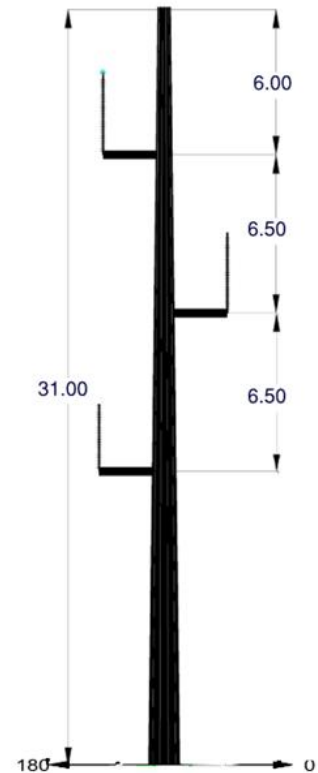


Figure 3: Termination Structure

Furthermore, approximately 8 km of skywire on the existing 230 kV single-circuit transmission line (Circuit X1P) emanating out of Dobbin TS will be upgraded to a larger sized skywire (i.e., from AW7#10 to AW7#8) to address increased fault levels from the addition of the proposed transmission line. Tower peak modifications will also be required to strengthen the tower structures for this larger sized skywire.

3.0 LINE REMOVAL

The Project will repurpose portions of existing transmission line corridors (approximately 50 km in total), as part of the route defined through the Class EA process. This will include the removal of approximately 196 transmission structures, conductor and associated components; as well as foundation removal to a depth of 1.5 m below grade, with backfilling to restore the lands. There will also be one single span of 230 kV Circuit T28C

removed at Clarington TS to accommodate the safe connection of the new Circuit T40P into its termination point at the station.

4.0 STATION WORK

The transmission station work will consist of terminal station modifications at Dobbin TS and Clarington TS, along with minor PCT modifications at remote stations, to accommodate the new transmission line. All expansion work at the stations is taking place within the existing station fence. The following outlines the specific work required at each of the facilities:

Dobbin TS

The scope of work to expand the existing station to facilitate the connection of the new 230 kV transmission line includes:

- Installation of one (1) new 230 kV diameter with three (3) new 230 kV circuit breakers, six (6) new breaker disconnect switches, and five (5) new line disconnect switch;
- Replacement of five (5) existing 230 kV circuit breakers and ten (10) new breaker disconnect switches to accommodate the increase in fault levels with the addition of the new 230 kV transmission line;
- Reconfiguration of the line entrances for three (3) existing 230 kV transmission lines (Circuits P15C, X1P and C27P) and re-terminate the lines into different breaker positions within the switchyard to accommodate the new 230 kV transmission line (Circuits T40P and T41P) into the station;
- Installation of one (1) new 230 kV entry for Circuit T41P and new bus work designed to have the same rating as the existing buses; and
- Installation of telecommunications, protection, control, SCADA and monitoring equipment within the existing relay building.

Clarington TS

The scope of work to expand the existing station to facilitate the connection of the new 230 kV transmission line includes:

- Installation of one (1) new 230 kV diameter with two (2) new 230 kV circuit breakers, four (4) new breaker disconnect switches, and one (1) new line disconnect switch to accommodate the connection of the new Circuit T41P;
- Repurpose the existing diameter and termination point of the de-energized section of the 230 kV Circuit T28C to accommodate the connection of the new Circuit T40P;
- Relocation of one (1) existing capacitor bank and associated equipment north of its current position to create sufficient space to build a new diameter;
- Installation of new bus work extending to the east of the 230 kV yard to complete the bus expansion and reconfigurations for line entrances into the station; and
- Installation of telecommunications, protection, control, SCADA and monitoring equipment within the existing relay building.

Remote Station Facilities

The scope of work includes updating relay protection, control, and telecommunication settings at Chat Falls SS, Havelock TS and Merivale TS resulting from the reconfiguration of the three existing 230 kV circuits at Dobbin TS; as well as updating the relay protection, control, and telecommunication settings at Cherrywood TS for the repurposing of the T28C breaker position for the new transmission line.

This page has been left blank intentionally.

OPERATIONAL DETAILS

The proposed facilities will be part of the East Ontario bulk transmission system and are required to increase bulk transfer capability to address the long-term capacity needs and support the reliable supply and secure operation of the bulk system serving the Peterborough to Quinte West and Ottawa regions. Hydro One protection, control and telecom facilities installed as part of the Project will protect the proposed 230 kV double-circuit transmission line by detecting faults and isolating faulted elements. The proposed facilities will be operated by Hydro One's ISOC as directed by the IESO. The terminal stations for the proposed 230 kV double-circuit transmission line will be Dobbin TS and Clarington TS, as described in the Application.

LAND MATTERS

1.0 THE ROUTE

The proposed 230 kV transmission line corridor, as established in the Class EA process in accordance with the *Ontario Environmental Assessment Act*, will be approximately 55 km in length extending from Dobbin TS (in the Township of Selwin) in a southwesterly direction to Clarington TS (in the Municipality of Clarington). The proposed transmission line will be sited within a ROW varying from 30 m to 46 m in width and passes primarily through agricultural lands, along with two small rural residential subdivisions in Burketon Station and Bethany. The majority of the transmission line corridor will be sited on privately owned lands; however, approximately 95% of the route will utilize and re-purpose portions of existing transmission line corridors for the proposed Project. Utilizing existing infrastructure and facilities is consistent with the Ministry of Municipal Affairs and Housing's *Provincial Planning Statement, 2024*¹ under the Planning Act, which states that the reuse of corridors that maintain the corridors integrity and co-location of linear infrastructure should be promoted, where appropriate.

2.0 DESCRIPTION OF LAND RIGHTS

The proposed Project will require Hydro One to acquire land rights from 183 directly impacted properties, consisting of 171 privately held properties (including 7 Conservation Authority properties), 10 municipally held properties, 1 provincially held property, and 1 railway property. The majority of properties will require Hydro One to acquire easement or fee simple interests, at the property owner's election. Hydro One is working with directly impacted property owners to acquire amicable voluntary agreements.

No new land rights are required for the modifications at the terminal stations as Hydro One's existing land rights are sufficient to accommodate the new transmission facilities.

¹ Ministry of Municipal Affairs and Housing's Provincial Planning Statement, 2024, under the Planning Act, Policy 3.3.4 and 3.3.5, p. 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 ²	195	92.90%
Municipal Lands	1	0.47%
Provincial Lands	0.1	0.05%
Railway Lands	0.1	0.05%

The transmission corridor will also rely on approximately 5 hectares of existing rights under Hydro One owned lands; as well as approximately 9 hectares of road allowance, in which Hydro One will rely on the land rights afforded by section 41 of the *Electricity Act*.

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 lot and concession numbers 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 owned lands (no new land rights required);
- Easement or fee simple rights (new land rights required);
- Rail crossing agreements (new land rights required); and
- Temporary access and/or construction rights on provincially owned, municipally owned and private properties for access roads, temporary work headquarters, laydown areas, and material storage facilities (new land rights required).

² Private Lands includes the seven Conservation Authority properties.

Hydro One will document all required new land rights for the proposed Project 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 – Fee Simple;
- Compensation and Incentive Agreement – Fee Simple;
- Rail Crossing Agreement (provided by rail company at a later date);
- Encroachment Permit (provided by Ministry of Transportation at a later date);
- Agreement for Temporary Rights;
- Off Corridor Access;
- Crop Land Out of Production Agreement; 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 per section 41(9) of the *Electricity Act*. All road crossings will be designed to meet CSA vertical clearance standards. Structures shall be located so that tower legs and guy wire anchor locations (above ground) are at least 18 m from the edge of parallel or crossing roads.

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 provincially owned, municipally owned and 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 transmission 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. To facilitate the required access to the properties affected by the transmission corridor in advance of Leave to Construct approval, Hydro One has been and will continue to enter into early access agreements with affected property owners. As of May 31, 2026, Hydro One has achieved voluntary early access agreements on approximately 98% of the privately held properties that require new land rights.

6.0 LAND ACQUISITION PROCESS

Hydro One is seeking voluntary property rights agreements with affected property owners along the proposed 230 kV transmission line corridor 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 acts 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 need 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 property owners since July 2024. 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. Hydro One began providing offers to affected property owners in March 2026.

As of May 31, 2026, 13 voluntary property settlement offers have been made, and 1 offer has been accepted. All remaining offers will be extended to affected property owners on an as-ready basis. All offers that have been extended to date are being reviewed by property owners and/or their legal counsel. 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 agreements.

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 31, 2026)

Property Type	Number of Properties	Early Access Agreement Offered	Early Access Agreement Achieved	Voluntary Settlement Agreements Offered	Voluntary Settlement Agreements Achieved	Issues	Resolution Approach
Private Lands ³	171	171	167	12	1	Tower design/ placement	Accommodate minor design requests, where feasible
Municipal Lands	10	10	10	1	0	None to date	N/A
Provincial Lands	1	1	1	0	0	None to date	N/A
Railway Lands	1	0	0	0	N/A	None to date	N/A

³ Private Lands includes the seven Conservation Authority properties.

7.0 LAND-RELATED FORMS

Provided as **Attachments 3 through 11** of this Schedule, are the land rights agreements that Hydro One intends to utilize to obtain the required new land rights for the proposed transmission corridor and for related Project activities. Table 3 below indicates the proceeding where the form of these agreements were previously approved.

Table 3 - Forms of Agreement Remaining Materially Unchanged

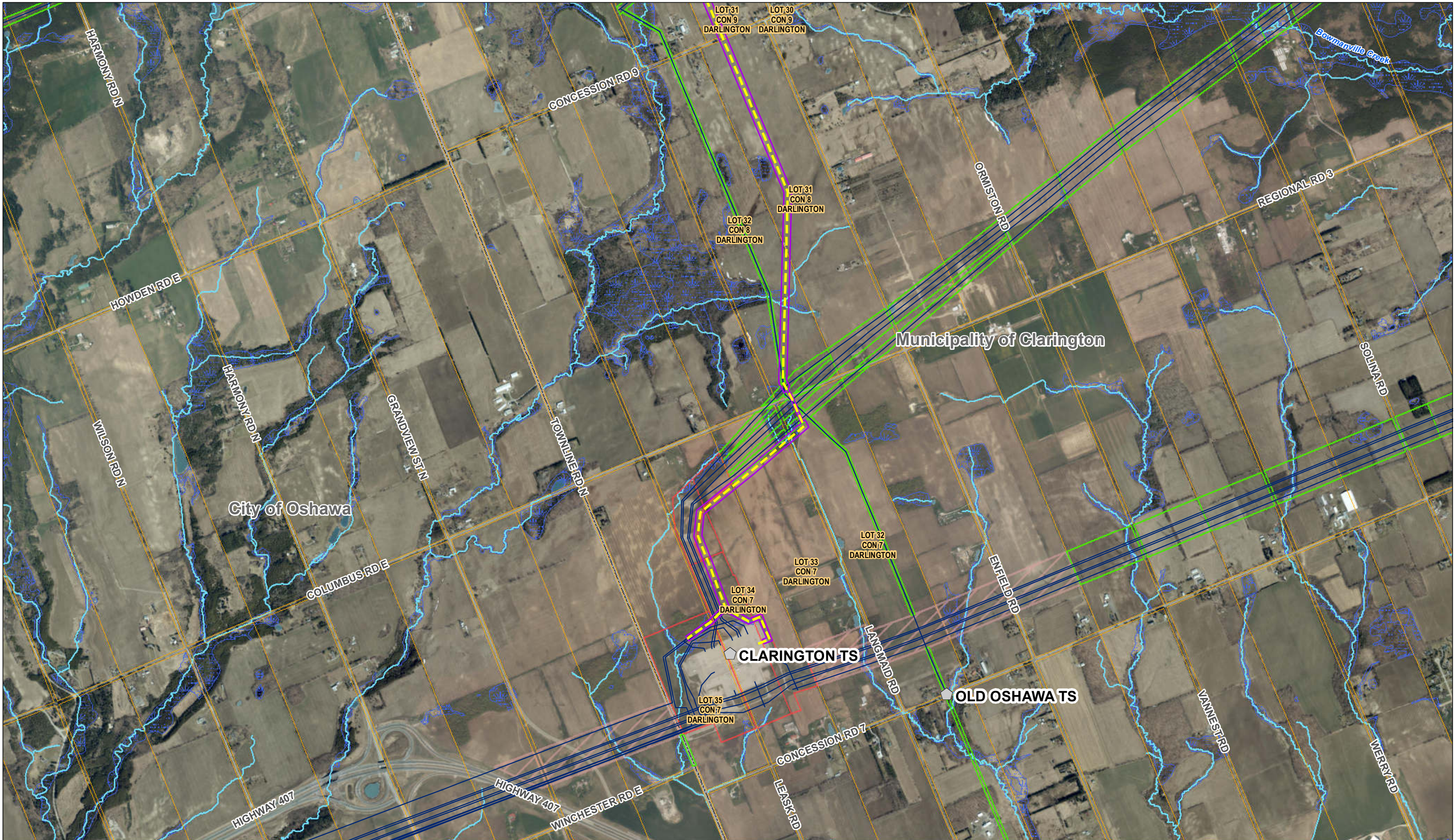
Form of Agreement	Attachment No.	Previous OEB Docket
Early Access Agreement	3	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 3
Option to Purchase a Limited Interest – Easement	4	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 4
Compensation and Incentive Agreement – Easement	5	EB-2024-0155, 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
Cropland Out of Production Agreement	10	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 11
Damage Claim Agreement/Waiver	11	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 12

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

- **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 agreement;
- **Compensation and Incentive Agreement – Easement:** This agreement is the same as approved in proceeding EB-2024-0155 with the exception of the trigger and timing for market value top-up in Clause 1 (b) and the Woodlot Compensation clause under Clause 2 (d) of the form of agreement;

- 1 • **Compensation and Incentive Agreement – Fee Simple:** This agreement is the
2 same as approved in proceeding EB-2024-0155 with the exception of the trigger
3 and timing for market value top-up in Clause 1 (b); the confirmation of actual lands
4 by survey under Clause 1 (c); the removal of the premium above fair market value
5 wording in Clause 2 (c); and the Woodlot Compensation clause under Clause 2 (d)
6 of the form of agreement; and
- 7 • **Crop Land Out of Production Agreement:** This agreement is the same as
8 approved in proceeding EB-2024-0155 with the exception of the inclusion of the
9 background “whereas” clauses and the payment terms framework.

DETAILED ROUTE MAP



Produced By: Hydro One Networks Inc., GIS Services
Date: May 26, 2026
Map24-025_DKPL_May2026_Section92_TileMap_PIN

Key Map

Title 1 of 10

Centerline for Proposed Project

ROW for Proposed Project

Station

Existing Transmission Line

Idle Transmission Line

Hydro One Owned Lands

Hydro One Existing Easement

Bill 58

Lot / Con

Railway

Watercourse

Wetlands

Waterbody

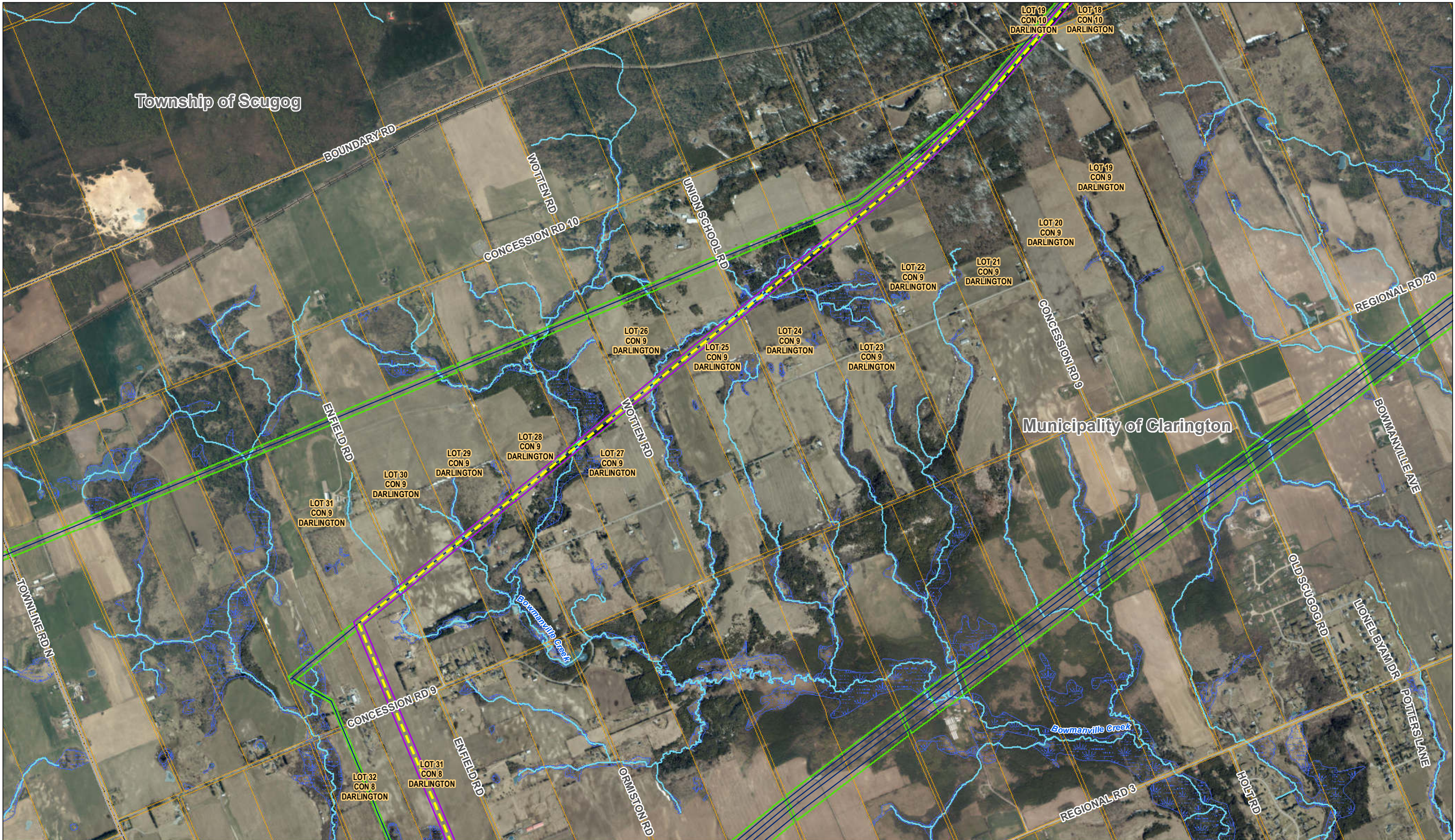
Municipal Boundary

Durham Kawartha Power Line Project

Detailed Route Map

1:20,000

0 0.5 1 km



Produced By: Hydro One Networks Inc., GIS Services
Date: May 26, 2026
Map24-025_DKPL_May2026_Section92_TileMap_PIN

Key Map

Tile 2 of 10

Centerline for Proposed Project	Station	Hydro One Owned Lands	Railway	Municipal Boundary
ROW for Proposed Project	Existing Transmission Line	Hydro One Existing Easement	Watercourse	
	Idle Transmission Line	Bill 58	Wetlands	
		Lot / Con	Waterbody	

**Durham Kawartha Power Line Project
Detailed Route Map**

1:20,000



Produced By: Hydro One Networks Inc., GIS Services
Date: May 25, 2025
Map24-025_DKPL_May2025_Section92_TitleMap_PIN

Key Map

Tile 3 of 10

Centerline for Proposed Project	Station	Hydro One Owned Lands	Railway	Municipal Boundary
ROW for Proposed Project	Existing Transmission Line	Hydro One Existing Easement	Watercourse	
	Idle Transmission Line	Bill 58	Wetlands	
		Lot / Con	Waterbody	

**Durham Kawartha Power Line Project
Detailed Route Map**

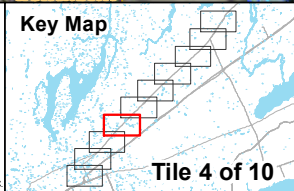
1:20,000





Produced By: Hydro One Networks Inc., GIS Services
Date: May 25, 2026
Map24-025_DKPL_May2026_Section92_TileMap_PIN

Key Map

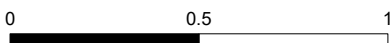


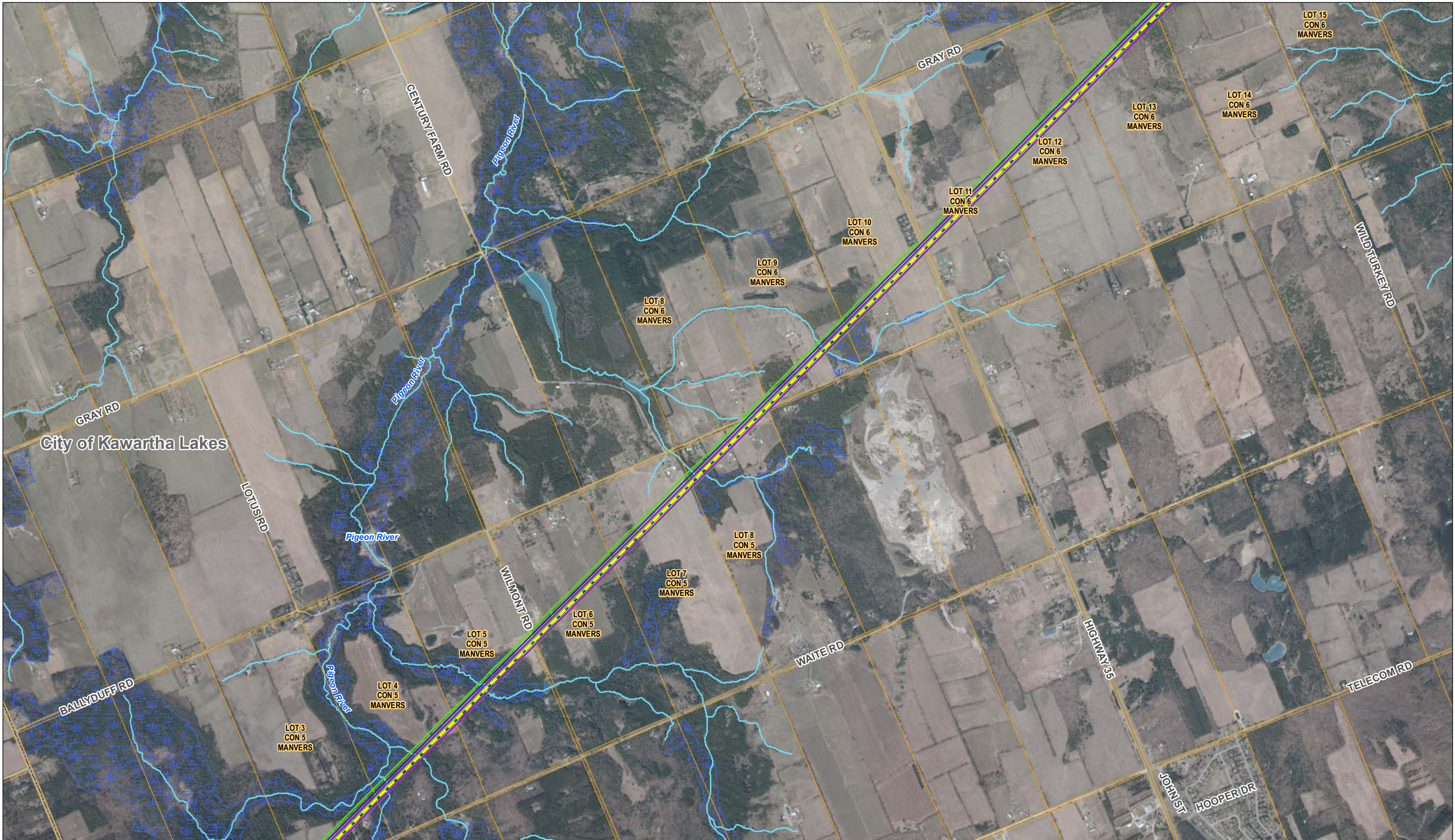
Tile 4 of 10

 Centerline for Proposed Project	 Station	 Hydro One Owned Lands	 Railway	 Municipal Boundary
 ROW for Proposed Project	 Existing Transmission Line	 Hydro One Existing Easement	 Watercourse	 Wetlands
	 Idle Transmission Line	 Bill 58	 Waterbody	
		 Lot / Con		

**Durham Kawartha Power Line Project
Detailed Route Map**

1:20,000





Produced By: Hydro One Networks Inc., GIS Services
Date: May 26, 2026
Map24-025_DKPL_May2026_Section92_TileMap_PIN

Key Map

Title 5 of 10

Centerline for Proposed Project	Station	Hydro One Owned Lands	Railway	Municipal Boundary
ROW for Proposed Project	Existing Transmission Line	Hydro One Existing Easement	Watercourse	
	Idle Transmission Line	Bill 58	Wetlands	
		Lot / Con	Waterbody	

**Durham Kawartha Power Line Project
Detailed Route Map**

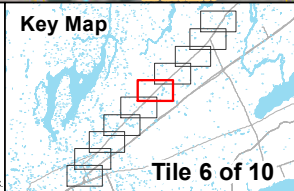
1:20,000





Produced By: Hydro One Networks Inc., GIS Services
Date: May 25, 2020
Map24-025_DKPL_May2020_Section92_TileMap_PIN

Key Map

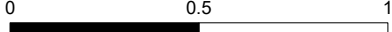


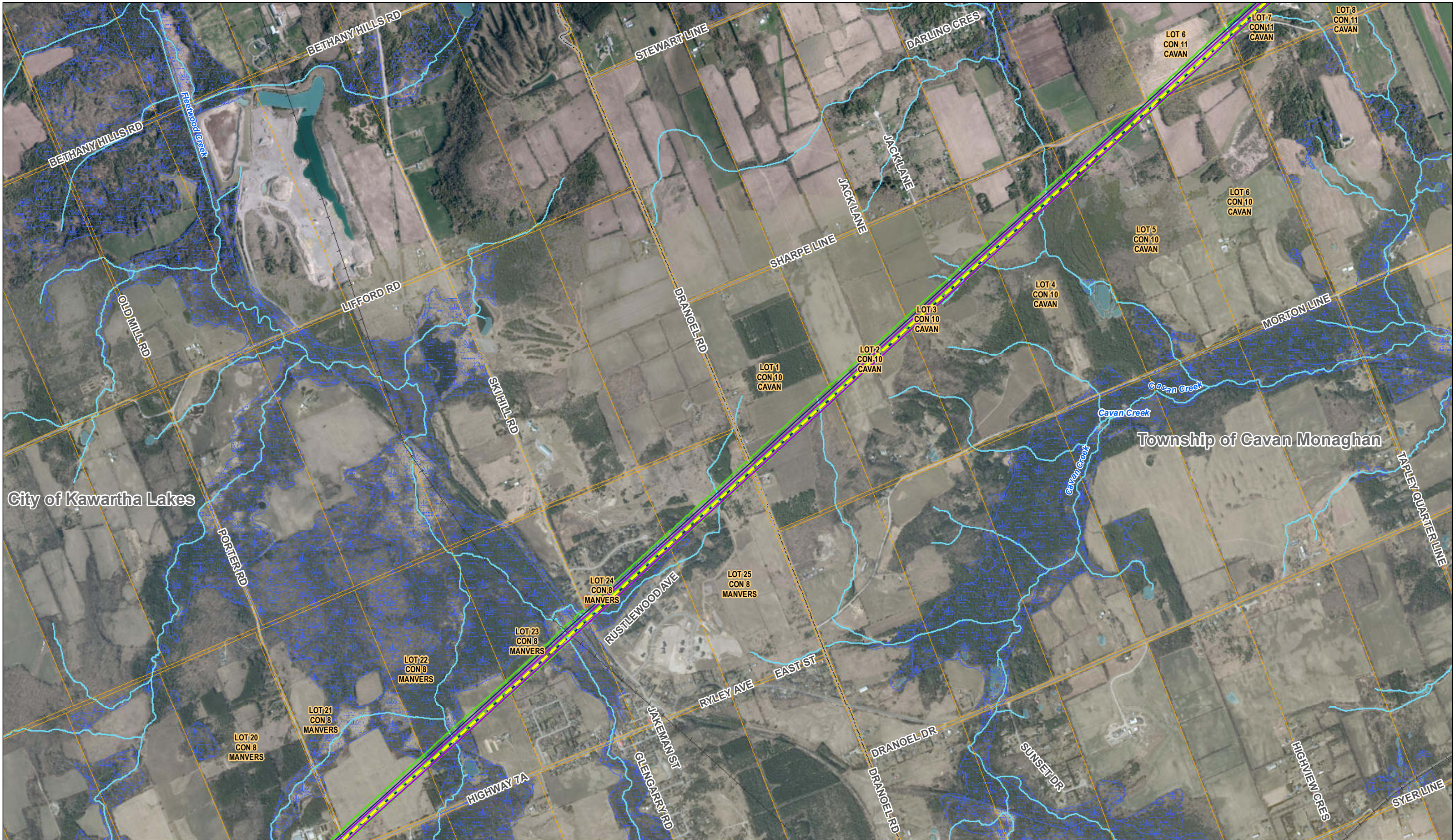
Title 6 of 10

 Centerline for Proposed Project	 Station	 Hydro One Owned Lands	 Railway	 Municipal Boundary
 ROW for Proposed Project	 Existing Transmission Line	 Hydro One Existing Easement	 Watercourse	
	 Idle Transmission Line	 Bill 58	 Wetlands	
		 Lot / Con	 Waterbody	

**Durham Kawartha Power Line Project
Detailed Route Map**

1:20,000





Produced By: Hydro One Networks Inc., GIS Services
Date: May 25, 2025
Map24-025_DKPL_May2025_Section92_TileMap_PIN

Key Map

Title 7 of 10

Centerline for Proposed Project	ROW for Proposed Project	Station	Existing Transmission Line	Idle Transmission Line
Hydro One Owned Lands	Hydro One Existing Easement	Bill 58	Lot / Con	

Railway	Municipal Boundary
Watercourse	Wetlands
Waterbody	

**Durham Kawartha Power Line Project
Detailed Route Map**

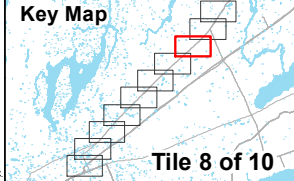
1:20,000





Produced By: Hydro One Networks Inc., GIS Services
Date: May 26, 2026
Map24-025_DKPL_May2026_Section92_TileMap_PIN

Key Map

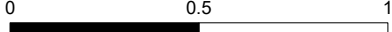


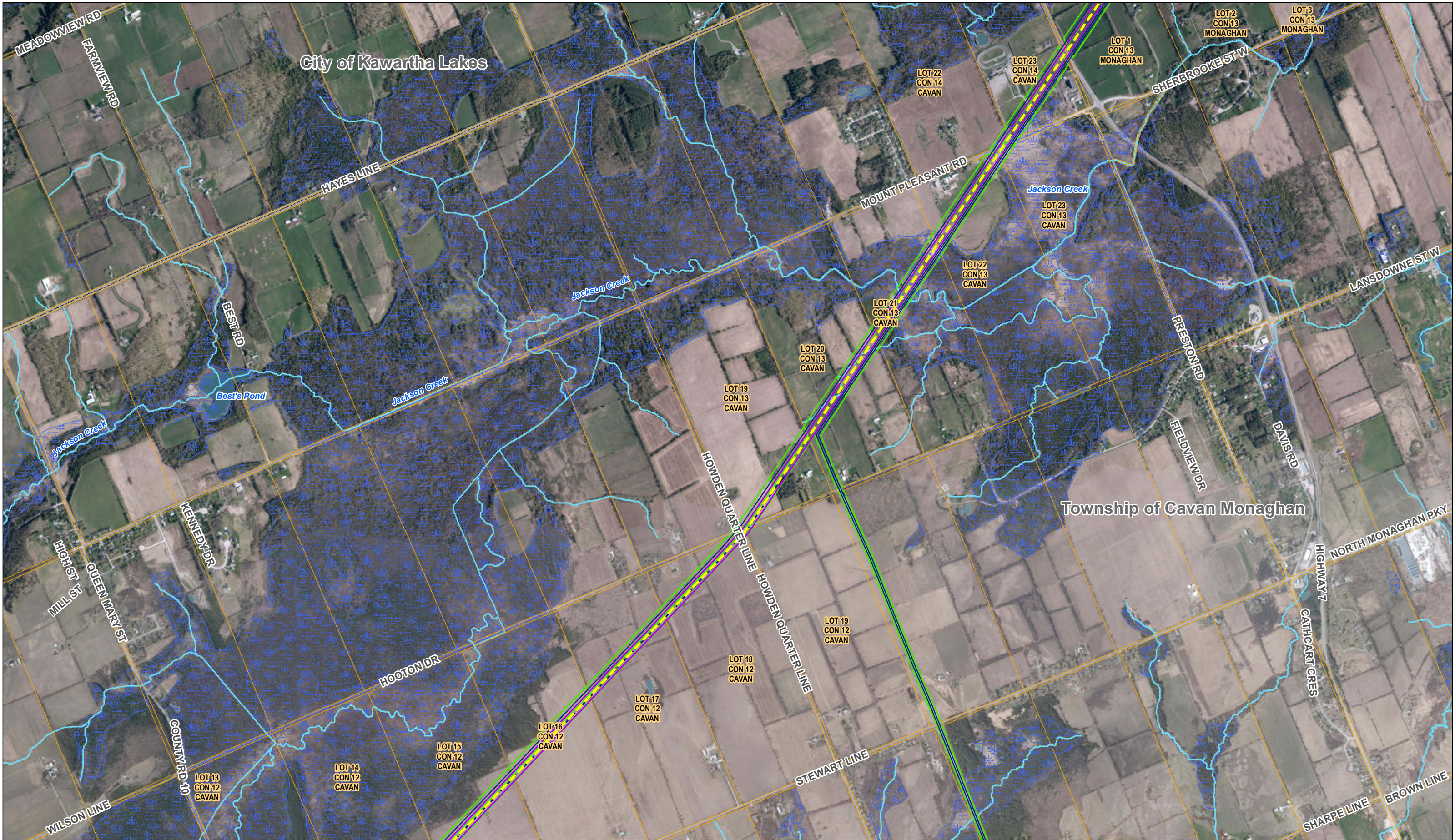
Title 8 of 10

 Centerline for Proposed Project	 Station	 Hydro One Owned Lands	 Railway	 Municipal Boundary
 ROW for Proposed Project	 Existing Transmission Line	 Hydro One Existing Easement	 Watercourse	
	 Idle Transmission Line	 Bill 58	 Wetlands	
		 Lot / Con	 Waterbody	

**Durham Kawartha Power Line Project
Detailed Route Map**

1:20,000





Produced By: Hydro One Networks Inc., GIS Services
Date: May 26, 2026
Map24-025_DKPL_May2026_Section92_TileMap_PIN

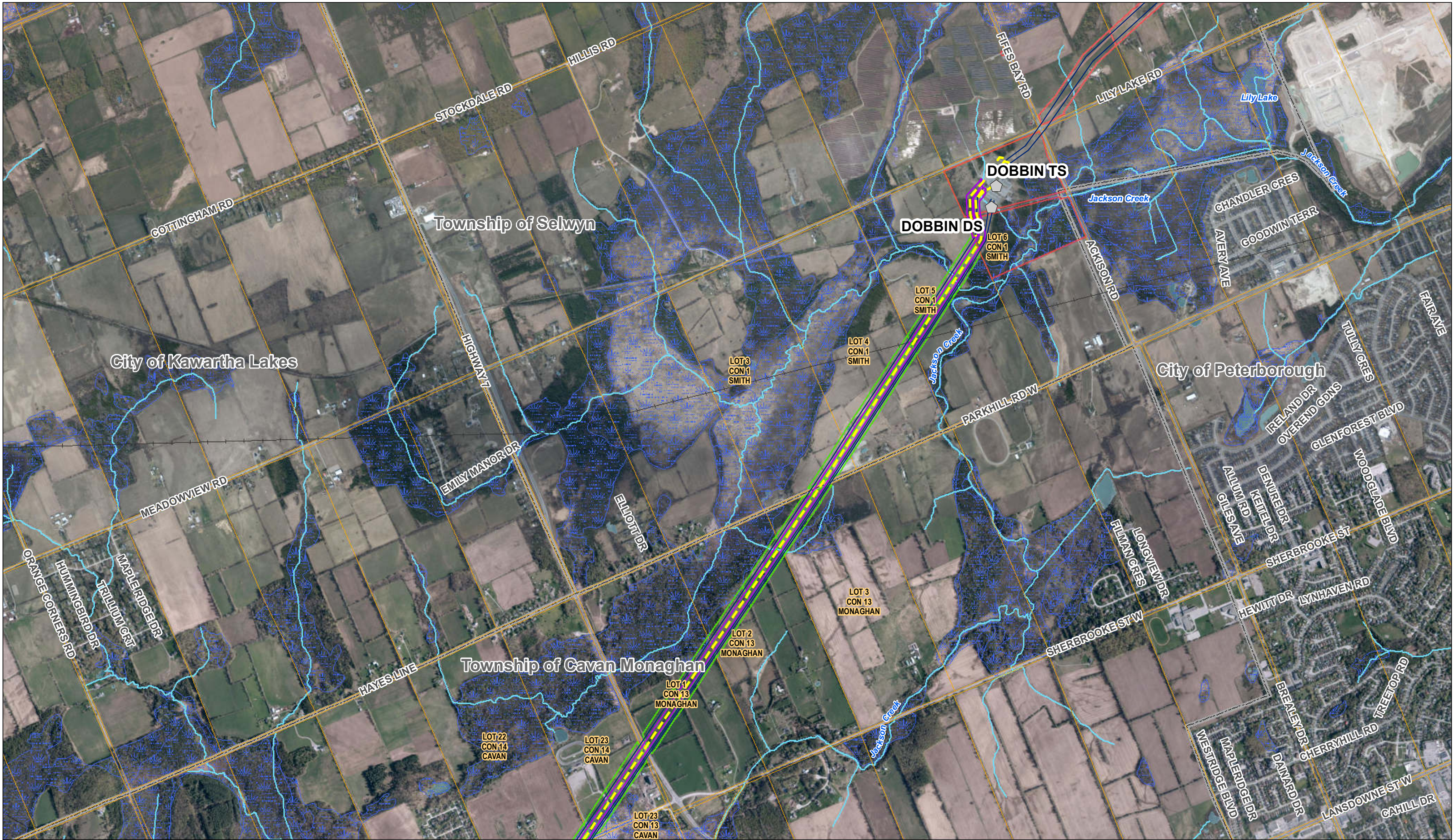
Key Map

Title 9 of 10

Centerline for Proposed Project	Station	Hydro One Owned Lands	Railway	Municipal Boundary
ROW for Proposed Project	Existing Transmission Line	Hydro One Existing Easement	Watercourse	
	Idle Transmission Line	Bill 58	Wetlands	
		Lot / Con	Waterbody	

**Durham Kawartha Power Line Project
Detailed Route Map**

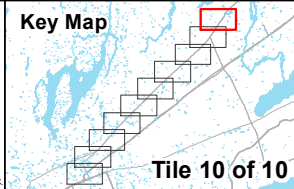
1:20,000





Produced By: Hydro One Networks Inc., GIS Services
Date: May 26, 2026
Map24-025_DKPL_May2026_Section92_TileMap_PIN

Key Map

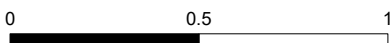


Tile 10 of 10

 Centerline for Proposed Project	 Station	 Hydro One Owned Lands	 Railway	 Municipal Boundary
 ROW for Proposed Project	 Existing Transmission Line	 Hydro One Existing Easement	 Watercourse	
	 Idle Transmission Line	 Bill 58	 Wetlands	
		 Lot / Con	 Waterbody	

**Durham Kawartha Power Line Project
Detailed Route Map**

1:20,000



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							
CL01	267390188	PART LOT 33 CONCESSION 7 DARLINGTON; PART LOT 34 CONCESSION 7 DARLINGTON AS IN N158815, SAVE AND EXCEPT PARTS 1,2,3,4, EXPROPRIATION PLAN DR2195168 SUBJECT TO AN EASEMENT AS IN DN19324 MUNICIPALITY OF CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL02	267390185	PART LOT 32 CON 7 DARLINGTON AS IN N117773 EXCEPT PARTS 12, 13 AND 14, 43R31093; S/T DN18852, DN19324 MUNICIPALITY OF CLARINGTON	Private	Yes	Fee Simple	Offer Accepted	
CL03	267390196	PART LOT 32 CONCESSION 7 DARLINGTON AS IN D497709 EXCEPT PARTS 15 & 16, 40R31093; S/T DN18852, DN19324 MUNICIPALITY OF CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL04	267390198	PART LOT 32 CONCESSION 8 AND PART ROAD ALLOWANCE BETWEEN LOTS 32 & 33 CONCESSION 8 DARLINGTON, PARTS 1 TO 11 40R19190, SAVE AND EXCEPT PARTS 1, 2, 3, 4, 5 & 6 40R31093; SUBJECT TO AN EASEMENT AS IN DN18735; SUBJECT TO AN EASEMENT AS IN DN19438; TOGETHER WITH AN EASEMENT AS IN N44310; MUNICIPALITY OF CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL05	267390169	FIRSTLY: PART LOT 32 CON 8 DARLINGTON; PART LOT 33 CON 8 DARLINGTON; PART ROAD ALLOWANCE BETWEEN LOTS 32 & 33 CON 8 DARLINGTON AS IN N89473, SAVE EXCEPT PARTS 1, 2 & 3, 40R27741 & PT 2, 40R29081; SUBJECT TO AN EASEMENT AS IN DN18868; SECONDLY: PT LT 33 & 34, CON 8, DARLINGTON PARTS 3 & 4, 40R29081 SUBJECT TO AN EASEMENT AS IN DN18868 MUNICIPALITY OF CLARINGTON	Conservation Authority	Yes	Easement Release	N/A	
CL05B	267390013	PT LT 31 CON 8 DARLINGTON AS IN N158816; S/T N158816; S/T DN19292; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL06	267400023	PT LT 32 CON 9 DARLINGTON PARTS 4, 5, 6, 7, 8 & 9 40R30094; S/T DN18836, DN20345 MUNICIPALITY OF CLARINGTON	Private	Yes	Easement Release	N/A	
CL06B	267390009	PT LT 31 CON 8 DARLINGTON AS IN N111304; T/W N44310; MUNICIPALITY OF CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL07	267400028	PT RDAL BTN LOTS 30 & 31 CON 9 DARLINGTON; PT LT 31 CON 9 DARLINGTON AS IN N28557 MUNICIPALITY OF CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL08	267400044	PT LT 30 CON 9 DARLINGTON PTS 1-3 40R18560; S/T DN19333; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL09	267400057	PT LT 29 CON 9 DARLINGTON PTS 1, 2 & 3 10R2131; S/T DN19175; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL10	267400098	RDAL BTN LTS 28 & 29 CON 9 DARLINGTON; PT LT 28 CON 9 DARLINGTON BEING TRAVELLED RD 5 OF PT 1 40R16505 & W OF PT 1 10R162; CLARINGTON	Municipal	Yes	Permanent Easement	Offer Pending	
CL11	267400065	PT LT 27 CON 9 DARLINGTON; PT LT 28 CON 9 DARLINGTON PTS 1, 2 & 3, 40R16505 & PT 1, 10R162; S/T DN19013, DN19333; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL12	267400100	PT LT 27 CON 9 DARLINGTON PTS 1-3, 10R2444, S/T DN18867 MUNICIPALITY OF CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL13	267400077	PT LT 27 CON 9 DARLINGTON AS IN N30103 (FIRSTLY) EXCEPT D417700, 10R2444; S/T DN18866, DN18867, DN20376; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL14	267400203	FIRSTLY: PART LOT 26 CONCESSION 9 DARLINGTON AS IN N137331; SUBJECT TO AN EASEMENT AS IN DN18866, DN20322, DN20376; CLARINGTON; SECONDLY: PART OF LOTS 25 AND 26, CONCESSION 9 DARLINGTON, BEING PARTS 2, 3, 4, 5 AND 6 ON 40R30654 SUBJECT TO AN EASEMENT OVER PART 3, 40R30654 AS IN DN20322 SUBJECT TO AN EASEMENT OVER PART 4, 40R30654 AS IN DN18936 MUNICIPALITY OF CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL15	267400083	PT LT 26 CON 9 DARLINGTON AS IN N98253, S/T RESERVATIONS OF MINES & MINERALS AS IN N98253; S/T DN18865, DN18866; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL16	267420097	PT LT 24 CON 9 DARLINGTON BEING TRAVELLED RD; RDAL BTN LTS 24 & 25 CON 9 DARLINGTON BTN CONCESSION RD 9 & CONCESSION RD 10; CLARINGTON	Municipal	Yes	Permanent Easement	Offer Pending	
CL17	267420099	PT LT 23 CON 9 DARLINGTON; PT LT 24 CON 9 DARLINGTON AS IN N19393 EXCEPT N41235; S/T DN18936, DN19042; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL18	267420098	PT LT 23 CON 9 DARLINGTON; PT LT 24 CON 9 DARLINGTON AS IN D396371; S/T DN18936, DN19042, DN20281, DN20443; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL19	267420101	PT LT 23 CON 9 DARLINGTON PTS 2-6, 10R2778; S/T DN18834, DN20453; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL20	267420154	RDAL BTN LTS 22 & 23 CON 9 DARLINGTON LYING N OF CONCESSION RD 9; CLARINGTON	Municipal	Yes	Permanent Easement	Offer Pending	
CL21	267420104	PT LT 22 CON 9 DARLINGTON AS IN D512650 LYING N OF THE TRAVELLED RD; S/T DN18965, DN20282; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL22	267420108	PT LT 21 CON 9 DARLINGTON AS IN D460505; S/T D460502; S/T DEBTS IN D460505; S/T DN18925, DN20284; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL23	267420153	RDAL BTN LTS 20 & 21 CON 9 DARLINGTON; CLARINGTON	Municipal	Yes	Permanent Easement	Offer Pending	
CL24	267420110	PT LT 20 CON 9 DARLINGTON AS IN D387793; S/T DN18833, DN20320; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL25	267420113	PT LT 19 CON 9 DARLINGTON; PT LT 20 CON 9 DARLINGTON AS IN N69544; S/T DN18925, DN20284; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL26	267420117	PT LT 19 CON 9 DARLINGTON AS IN D491791; S/T DN18925, DN20284; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL27	267420196	PT LT 19 CON 9 DARLINGTON AS IN D430924; S/T DN20319; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL28	267410058	PCL 12-1 SEC 10M753; LT 12 PL 10M753 TOWN OF NEWCASTLE, IN THE REGIONAL MUNICIPALITY OF DURHAM (FORMERLY IN THE TOWNSHIP OF DARLINGTON, COUNTY OF DURHAM); S/T RIGHT AS IN NL1634 ; S/T DN18965,DN20188 CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL29	267410059	PCL 13-1 SEC 10M753; LT 13 PL 10M753 TOWN OF NEWCASTLE, IN THE REGIONAL MUNICIPALITY OF DURHAM (FORMERLY IN THE TOWNSHIP OF DARLINGTON, COUNTY OF DURHAM); S/T RIGHT AS IN NL1604 ; S/T DN18965,DN20188 CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL30	267410060	PCL 14-1 SEC 10M753; LT 14 PL 10M753 TOWN OF NEWCASTLE, IN THE REGIONAL MUNICIPALITY OF DURHAM (FORMERLY IN THE TOWNSHIP OF DARLINGTON, COUNTY OF DURHAM); S/T RIGHT AS IN NL1632 ; S/T DN18965,DN20188 CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL31	267410079	PCL 12-1 SEC 10M765; LT 12 PL 10M765 TOWN OF NEWCASTLE, IN THE REGIONAL MUNICIPALITY OF DURHAM (FORMERLY IN THE TOWNSHIP OF DARLINGTON, COUNTY OF DURHAM); S/T A RIGHT AS IN NLS289 ; S/T DN20188,NLS134 CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL32	267410078	PCL 11-1 SEC 10M765; LT 11 PL 10M765 TOWN OF NEWCASTLE, IN THE REGIONAL MUNICIPALITY OF DURHAM (FORMERLY IN THE TOWNSHIP OF DARLINGTON, COUNTY OF DURHAM); S/T RIGHT AS IN NL7516 ; S/T DN18965,DN20188, NLS134 CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	

	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)
CL33	267410077	PCL 10-1 SEC 10M765; LT 10 PL 10M765 TOWN OF NEWCASTLE, IN THE REGIONAL MUNICIPALITY OF DURHAM (FORMERLY IN THE TOWNSHIP OF DARLINGTON, COUNTY OF DURHAM); S/T RIGHT AS IN NLS520 ; S/T DN18965,DN20188, NLS134 CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL34	267410083	PCL 16-1 SEC 10M765; LT 16 PL 10M765 TOWN OF NEWCASTLE, IN THE REGIONAL MUNICIPALITY OF DURHAM (FORMERLY IN THE TOWNSHIP OF DARLINGTON, COUNTY OF DURHAM); S/T A RIGHT AS IN NL4968 ; S/T DN20188,NL4966 CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL35	267410084	PCL 17-1 SEC 10M765; LT 17 PL 10M765 TOWN OF NEWCASTLE, IN THE REGIONAL MUNICIPALITY OF DURHAM (FORMERLY IN THE TOWNSHIP OF DARLINGTON, COUNTY OF DURHAM); S/T RIGHT AS IN NL4386 ; S/T DN18965,DN20188 CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL36	267410094	PCL 11-1 SEC 10M770; LT 11 PL 10M770 TOWN OF NEWCASTLE, IN THE REGIONAL MUNICIPALITY OF DURHAM (FORMERLY IN THE TOWNSHIP OF DARLINGTON, COUNTY OF DURHAM); S/T RIGHT AS IN NLS664 ; S/T DN18965,DN20188 CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL37	267410093	PCL 10-1 SEC 10M770; LT 10 PL 10M770 TOWN OF NEWCASTLE, IN THE REGIONAL MUNICIPALITY OF DURHAM (FORMERLY IN THE TOWNSHIP OF DARLINGTON, COUNTY OF DURHAM); S/T RIGHT AS IN NLS180 ; S/T DN18965,DN20188 CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL38	267410097	PT LT 17 CON 10 DARLINGTON AS IN N142140; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL39	267420083	PT LT 17 CON 10 DARLINGTON AS IN N42405 (1STLY PCLS B & C) & N38702; T/W N38702; S/T DN18965, DN20335, DN22062; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL40	267420151	RDAL BTN LTS 16 & 17 CON 10 DARLINGTON; CLARINGTON	Municipal	Yes	Permanent Easement	Offer Pending	
CL41	267420084	PT LT 15 CON 10 DARLINGTON; PT LT 16 CON 10 DARLINGTON AS IN N42405 (THIRDLY); S/T DN22062; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL43	267420165	PT LT 15 CON 10 DARLINGTON; PT LT 16 CON 10 DARLINGTON AS IN N42405 (SECONDLY); S/T DN18837, DN20285, DN22062; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL44	267420085	PT LT 15 CON 10 DARLINGTON AS IN DN16023; S/T DN18837, DN20285; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CL45	267420152	RDAL BTN LTS 14 & 15 CON 10 DARLINGTON; CLARINGTON	Municipal	Yes	Permanent Easement	Offer Pending	
CL46	267420163	PT LT 14 CON 10 DARLINGTON AS IN DN16023; S/T DN20285; CLARINGTON	Private	Yes	Permanent Easement	Offer Pending	
CM01	280020247	PT LT 1 CON 10 CAVAN, AS IN CMR62110, EXCEPT PT 1 PL 9R2641, EXCEPT PT 1 PL 45R15714 SUBJECT TO AN EASEMENT AS IN CVNC4321 SUBJECT TO AN EASEMENT AS IN CVNC4793 TOWNSHIP OF CAVAN-MONAGHAN	Private	Yes	Permanent Easement	Offer Pending	
CM02	280020243	PT LT 2 CON 10 CAVAN, AS IN R660305, EXCEPT PTS 1 & 2 PL 45R15329 SUBJECT TO AN EASEMENT AS IN CVNC4322 SUBJECT TO AN EASEMENT AS IN CVNC4807 TOWNSHIP OF CAVAN-MONAGHAN	Private	Yes	Permanent Easement	Offer Pending	
CM03	280020250	PT LT 2 CON 10 CAVAN, AS IN R658735, EXCEPT PTS 1 AND 2 PL 45R15867 SUBJECT TO AN EASEMENT AS IN CVNC4323 SUBJECT TO AN EASEMENT AS IN CVNC4794 TOWNSHIP OF CAVAN-MONAGHAN	Private	Yes	Permanent Easement	Offer Pending	
CM04	280020160	PT LT 3 CON 10 CAVAN AS IN R609914; S/T CVNC4403, CVNC4795; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM05	280020163	PT LT 4 CON 10 CAVAN AS IN R629683; S/T CVNC4324, CVNC4796 TWP OF CAVAN MONAGHAN	Private	Yes	Permanent Easement	Offer Pending	
CM06	280020165	PT LT 4 CON 10 CAVAN AS IN CMR21594 EXCEPT PT 1, 2 & 4 9R2361; S/T CMR100600; S/T CVNC4325, CVNC4896; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM07	280020256	PT LT 5 CON 10 CAVAN AS IN CMR2743 (FIRSTLY); S/T CVNC4326, CVNC4797 ; EXCEPT PT 1 PL 45R15050 SAVE & EXCEPT PTS 1,2,3,4, ON 45R16167 ; CAVAN MONAGHAN	Private	Yes	Permanent Easement	Offer Pending	
CM08	280020255	PT LT 5 CON 10 CAVAN BEING PARTS 1,2 ON PLAN 45R-16167; S/T CVNC4326, CVNC4797; CAVAN MONAGHAN	Private	Yes	Permanent Easement	Offer Pending	
CM09	280020254	PART LOT 5 CON 10 CAVAN PARTS 3 & 4 45R16167; S/T CVNC4326, CVNC4797; CAVAN MONAGHAN	Private	Yes	Permanent Easement	Offer Made	
CM10	280020229	W 1/2 LT 6 CON 10 CAVAN; PT LT 5 CON 10 CAVAN AS IN R668931, S/T CVNC4327, CVNC4834 ; CAVAN MONAGHAN	Private	Yes	Permanent Easement	Offer Pending	
CM11	280020148	PT LT 6 CON 11 CAVAN AS IN CMR2743 (SECONDLY); CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM12	280020170	PT LT 7 CON 11 CAVAN AS IN R656744 (FIRSTLY); S/T CVNC4329, CVNC4828; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM13	280020175	PT LT 8 CON 11 CAVAN AS IN CMR72721; S/T DEBTS IN CMR47139; S/T CVNC4330, CVNC4836; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM14	280020177	PT LT 9 CON 11 CAVAN AS IN CMR106144; S/T DEBTS IN CMR26692; S/T CVNC4331, CVNC4808; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM15	280020176	PT LT 9 CON 11 CAVAN AS IN R703901; S/T CVNC4478, CVNC4944; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM16	280020178	PT LT 10 CON 11 CAVAN AS IN R670920; S/T DEBTS IN R670920; S/T BENEFICIARIES INTEREST IN R670920; S/T CVNC4331, CVNC4838; S/T EXECUTION 01-0000130, IF ENFORCEABLE; S/T EXECUTION 02-0000377, IF ENFORCEABLE; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM17	280020180	LOT 11 CONCESSION 11 CAVAN EXCEPT PART 1 9R1553; S/T CVNC4333, CVNC4809; TOWNSHIP OF CAVAN-MONAGHAN	Private	Yes	Permanent Easement	Offer Pending	
CM18	280020293	PART LOT 12 CONCESSION 11, CAVAN, PARTS 1,2,3 PLAN 9R531, EXCEPT PART 1 PLAN 9R1310, PART 1 PLAN 45R10249 AND PARTS 1 AND 2 PLAN 45R17446 SUBJECT TO AN EASEMENT AS IN CVN4335 SUBJECT TO AN EASEMENT AS IN CVN4773 TWP OF CAVAN MONAGHAN	Private	Yes	Permanent Easement	Offer Pending	
CM19	280020270	PART LOT 12, CONCESSION 11, CAVAN, AS IN R737826 SAVE AND EXCEPT PARTS 1 TO 5, PLAN 45R-16891 ; DESCRIPTION MAY NOT BE ACCEPTABLE IN FUTURE AS IN R737826 TOGETHER WITH AN EASEMENT OVER PART LOT 12, CONCESSION 11, CAVAN, PART 4, PLAN 45R-16891 AS IN PE3263	Private	Yes	Permanent Easement	Offer Pending	
CM20	280030003	PT LT 13 CON 11 CAVAN AS IN R693643; S/T CVNC4336, CVNC4829; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM21	280000446	S1/2 LT 13 CON 12 CAVAN EXCEPT PT 1, 45R13670; S/T CMR34799; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM22	280000283	W1/2 LT 14 CON 12 CAVAN; S/T CMR34799; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM23	280000284	PT LT 14 CON 12 CAVAN PT 1-3 9R2750; S/T INTEREST IN CMR30811; S/T CVNC4337, CVNC4799; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM24	280000285	PT LT 14 CON 12 CAVAN PT 4-7 9R2750; S/T CVNC4337, CVNC4799; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	

	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)
CM25	280000287	S1/2 LT 15 CON 12 CAVAN; S/T CVNC4349, CVNC4800; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM26	280000516	LT 16 CON 12 CAVAN; S/T CVNC4340, CVNC4810; PART LOT 17 CON 12 CAVAN, PART 2 ON PLAN 45R17172; CAVAN MONAGHAN	Private	Yes	Permanent Easement	Offer Pending	
CM27	280000509	N1/2 LOT 17, CONCESSION 12 CAVAN; NW1/4 LOT 18, CONCESSION 12 CAVAN; SAVE & EXCEPT PART 1, 9R-1350, PART 1, 9R-650, PARTS 1, 2, 3 & 4, 45R-16764 SUBJECT TO AN EASEMENT AS IN CVNC4341 SUBJECT TO AN EASEMENT AS IN CVNC4830 TOWNSHIP OF CAVAN-MONAGHAN	Private	Yes	Permanent Easement	Offer Pending	
CM28	280000508	PART OF LOT 18, CONCESSION 12 CAVAN DESIGNATED AS PARTS 1, 2, 3, & 4, 45R-16764; S/T EASEMENT OVER PART 3, 45R-16764 AS IN CVNC4341; S/T EASEMENT OVER PART 4, 45R-16764 AS IN CVNC4830 TOWNSHIP OF CAVAN-MONAGHAN	Private	Yes	Permanent Easement	Offer Pending	
CM29	280000292	E1/2 LT 18 CON 12 CAVAN; S/T CVNC4340, CVNC4810; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM30	280000294	PT LT 19 CON 12 CAVAN, BEING PTS 1 AND 2 ON PL 45R14958, S/T CMR6201 TOWNSHIP OF CAVAN-MONAGHAN	Private	Yes	Permanent Easement	Offer Pending	
CM31	280000381	W1/2 LT 19 CON 13 CAVAN EXCEPT PT 8 9R807; S/T CMR6201, CVNC4440; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM32	280000382	E1/2 LT 19 CON 13 CAVAN EXCEPT PT 9 9R807, PT 1 9R2271; S/T CVNC4343, CVNC4811, R571428; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM33	280000384	W1/2 LT 20 CON 13 CAVAN EXCEPT PT 10 & 11 9R807; S/T CVNC4344, CVNC4801, CVNC5203, R571438, R601721E; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM34	280000448	PT LT 20 CON 13 CAVAN AS IN R724010; S/T CVNC4345, CVNC4837, CVNC5230, R571437; CVN-MIL-NMO TOWNSHIP OF CAVAN-MONAGHAN	Private	Yes	Permanent Easement	Offer Pending	
CM35	280000387	W1/2 LT 21 CON 13 CAVAN EXCEPT PT 1 9R490, PT 14 & 16 9R807, PT 1 9R673; S/T CVNC4309, CVNC4729, CVNC5143, R571436; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM36	280000470	NE 1/ LT 21 CON 13 CAVAN; PT N 1/2 LT 22 CON 13 CAVAN; AS IN R739376 SUBJECT TO AN EASEMENT AS IN R571424 SUBJECT TO AN EASEMENT AS IN CVNC4445 SUBJECT TO AN EASEMENT AS IN CVNC4802 SUBJECT TO AN EASEMENT AS IN CVNC5190	Private	Yes	Permanent Easement	Offer Pending	
CM37	280000520	PART LOTS 21-23 CONCESSION 13 CAVAN AS IN CMR26191, CMR24836, CMR23246, CMR22631, CMR61470, CMR20354 EXCEPT CMR20874, CMR20875, PARTS 23 & 24 PLAN 9R807 AND PARTS 1 & 2 PLAN 45R17305; S/T CVNC4445, CVNC4802, CVNC5190, CVNC5211, R571433; CVN-MIL-NMO	Conservation Authority	Yes	Permanent Easement	Offer Made	
CM38	280000423	PT LT 22 CON 14 CAVAN PT 1 & 2 9R1116; S/T CVNC4351, CVNC4833, R571427; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM39	280000424	PT LT 23 CON 14 CAVAN AS IN R673165; S/T THE RIGHTS OF OWNERS OF ADJOINING PARCELS IF ANY UNDER R650521; S/T CVNC4352, CVNC4803, CVNC5207, R571423; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM40	280000425	PT LT 23 CON 14 CAVAN AS IN CMR85868 EXCEPT PT 1 R692287; S/T CVNC4350, CVNC4757, CVNC5288, R571430; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM41	280370131	PT W 1/2 LT 1 CON 13 N MONAGHAN PT 2 45R534 ; S/T Q13290,Q13899,Q14559,R571425 CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM42	280370175	PT E 1/2 LT 1 CON 13 (NORTH MONAGHAN), PTS 1, 2, 3 & 4 45R12191, S/T Q13288, S/T Q13964, S/T Q14552, S/T R571422 ; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM43	280370176	PT E 1/2 LT 1 CON 13 (NORTH MONAGHAN), AS IN R606705, EXCEPT R528476, R528477, R669390 & PTS 1, 2, 3 & 4 45R12191, S/T Q13288, S/T Q13964, S/T Q14552, S/T R571422 ; CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM44	280370112	PT W 1/2 LT 2 CON 13 N MONAGHAN PT 1 45R4006, PTS 2 & 3 45R1583; S/T R416947; S/T & T/W R416945 & R416946 ; S/T Q13288,Q13964,Q14506,R571432 CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM45	280370109	PT W 1/2 LT 2 CON 13 N MONAGHAN PTS 4, 5 & 6 45R1583, EXCEPT PT 3 45R4659 & PT 5 45R5085; S/T R416945; T/W R416946 & R416947 ; S/T Q13288,Q13964,Q14506,R571434 CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM46	280370101	PT E 1/2 LT 2 CON 13 NORTH MONAGHAN AS IN Q14801, EXCEPT R638664, R554946, PT 4 45R4659, PTS 1 & 2 45R9107, PTS 1, 3, 6, 10 & 11 45R2880, PTS 1 TO 4 45R11078, PTS 10 & 11 R180668; S/T R551598, R553481, R358882 & R328884; T/W R328884 ; S/T Q13289,Q13900, Q14535,R571421 CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM47	280370097	PT LT 3 CON 13 NORTH MONAGHAN AS IN R371373, EXCEPT PTS 5 & 6 45R4659, PT 15 ON R185522, & PT 15 ON R180668 ; S/T Q13840,Q14507,R571435 CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
CM48	280370095	PT LT 3 CON 13 NORTH MONAGHAN; PT E 1/2 LT 4 CON 13 N MONAGHAN; PT W 1/2 LT 4 CON 13 NORTH MONAGHAN AS IN R182536; EXCEPT PTS 7 & 8 45R4659 & PTS 16 & 19 R180668 ; S/T Q13333,Q13908,Q14577 CVN-MIL-NMO	Private	Yes	Permanent Easement	Offer Pending	
K01	632680053	PT LT 1-2 CON 4 MANVERS PT 1, 2 & 3, 9R2118; PT 2, 3 & 4, 57R8249; PT 1, 2, 3, 4, 5 & 6, 9R1363 EXCEPT PT 5, 57R8249; S/T MVB15707, MVB15708, MVB16376, MVB16438, MVD9014; CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Made	
K02	632680060	PT LT 2 CON 4 MANVERS AS IN R391100; S/T MVB15708; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K03	632670070	PT LT 2 CON 5 MANVERS AS IN R403989; S/T MVB15708; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Made	
K04	632670073	W1/2 LT 3 CON 5 MANVERS; S/T MVB15709, MVB16375; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Made	
K05	632670074	PT LT 3 CON 5 MANVERS AS IN MV86530; S/T MVB15840, MVB16385; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K06	632670075	PT LT 3 CON 5 MANVERS AS IN R322600; S/T MVB15840, MVB16385; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K07	632670076	PT LT 3 CON 5 MANVERS AS IN R291262; S/T MVB15840, MVB16385; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K08	632670077	PT LT 3 CON 5 MANVERS AS IN R416304; S/T MVB15840, MVB16385; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K09	632670093	PT LT 4 CON 5 MANVERS PT 1, 2, 3, 4, 5, 6, 7 57R10107; S/T EASEMENT OVER PT 4 57R10107 IN FAVOUR OF PT LT 4 CON 5 MANVERS, PT 2 9R358 AS IN R424081 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Made	
K10	632670096	PT LT 5 CON 5 MANVERS AS IN MV104825; S/T MVB15789, MVB16373; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K11	632670097	PT LT 5 CON 5 MANVERS AS IN R316664; S/T MVB15793, MVB16372; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Made	
K12	632670102	PT LT 6 CON 5 MANVERS PT 1, 4 & 5, 9R1453; S/T R413289; S/T MVB16372 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K13	632670103	PT LT 6 CON 5 MANVERS PT 2-4, 57R7359; S/T MVB15793, MVB16372; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K14	632670105	PT LT 6 CON 5 MANVERS AS IN R414056; S/T MVB15805, MVB16371 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K15	632670107	PT LT 6 CON 5 MANVERS AS IN MV109486 EXCEPT PT 1, 57R8516; S/T MVB15805, MVB16371; CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K16	632670112	PT LT 7 CON 5 MANVERS AS IN R309406 EXCEPT PT 1, 57R7364; S/T MVB15790, MVB16370; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	

	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)
K17	632670114	PT LT 7 CON 5 MANVERS AS IN R355738 EXCEPT PT 1, 57R8406; S/T MVB15711, MVB16369; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K18	632670119	PT LT 8 CON 5 MANVERS PT 1-3, 9R1692 EXCEPT PT 1-2, 9R2013; S/T MVB15712, MVB16368; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K19	632670118	PT LT 8 CON 5 MANVERS AS IN MV79990 EXCEPT PT 1, 9R2522; S/T MVB15712, MVB16368; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K20	632670123	PT LT 8 CON 5 MANVERS AS IN MV75400; S/T MVB15712, MVB16368; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K21	632670292	PT LT 8 CON 6 MANVERS AS IN MVD14359, EXCEPT PT 1, 9R2738; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K22	632670290	S 1/2 LT 9 CON 6 MANVERS EXCEPT PT 1, 9R1238; S/T MVB15714, MVB16366; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K23	632670289	PT LT 9 CON 6 MANVERS PT 1, 9R1238; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K24	632670288	PT LT 10 CON 6 MANVERS PT 2 - 5, 9R480; S/T MVB15715, MVB16396; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K25	632670284	PT LT 10 CON 6 MANVERS AS IN R323308; S/T MV58362, MVB15716, MVB16365; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K26	632660148	PT LT 11 CON 6 MANVERS AS IN R323213; S/T MVB15717, MVB16364; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K27	632660150	PT LT 11 CON 6 MANVERS AS IN R337715; S/T MVB15718, MVB16363; CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Made	
K28	632660153	PT LT 12-13 CON 6 MANVERS AS IN MV97709; S/T MVB15719, MVB15720, MVB16361, MVB16362 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K29	632660157	E1/2 LT 13 CON 6 MANVERS; S/T MVB15721, MVB16360; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Made	
K30	632660158	N1/2 LT 14 CON 6 MANVERS EXCEPT PT 1, 9R2356; S/T MVB15722, MVB16335; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K31	632660161	PT LT 15 CON 6 MANVERS AS IN MV86133; PT 1 & 2, 9R926; S/T MVB16357; KAWARTHA LAKES	Municipal	Yes	Permanent Easement	Offer Pending	
K32	632660144	S1/2 LT 15 CON 7 MANVERS EXCEPT PT 1 & 3, 57R8017; S/T MV37911, MVB15724, MVB16395; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K33	632660227	S1/2 LT 16 CON 7 MANVERS EXCEPT PT 1, 9R2407; S/T MV36725, MVB15725, MVB16379; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K34	632660230	S1/2 LT 17 CON 7 MANVERS EXCEPT PT 1, 2 & 3, 57R8320; S/T MV36726, MV36996, MVB15726, MVB16358; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K35	632660224	PT LT 16-17 CON 7 MANVERS PT 2, 3, 4, 5 & 6, 9R1098; S/T MVB15727, MVB16336, R36808; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K36	632660232	LT 18 CON 7 MANVERS EXCEPT HWYM126; S/T MV36998, MVB15728, MVB16357 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K37	632660233	N 1/2 LT 19 CON 7 MANVERS S OF HWYM35 & HWYM126; S/T MVB16123, MVB16334; CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K38	632660237	NW 1/4 LT 20 CON 7 MANVERS LYING S OF HWYM126; S/T MVB15729, MVB15933, MVB16356; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K39	632660238	PT LT 20 CON 7 MANVERS AS IN R357805; S/T MVB15916, MVB15934, MVB16333 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K40	632650297	S1/2 LT 20 CON 8 MANVERS EXCEPT HWYM126; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K41	632650302	PT LT 21 CON 8 MANVERS AS IN R417583; CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K42	632650303	PT LT 22 CON 8 MANVERS AS IN R451792 EXCEPT HWYM126; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K43	632650304	PT LT 22 CON 8 MANVERS AS IN R403369 EXCEPT HWYM126; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Made	
K44	632650305	E1/2 LT 22 CON 8 MANVERS EXCEPT HWYM126; S/T MVD17528 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K45	632650077	PCL 23-1 SEC 9-CON 8 MANVERS; PT LT 23 CON 8 MANVERS PT 1 & 2 9R969; S/T LT1254, MVB16330; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K46	632650411	PT LT 23 CON 8 MANVERS AS IN R347370 PORTION 1 & 2; PT LT 20-21, 23 PL 5 MANVERS; LT 24-25 PL 5 MANVERS; PT LT 28-29 PL 5 MANVERS; LT 30-31 PL 5 MANVERS; PT WILSON ST, AGNES ST, GORE ST PL 5 MANVERS; PT LT 24 CON 8 MANVERS AS IN R347369 PORTION 18 - 27; KAWARTHA LAKES	Municipal	Yes	Permanent Easement	Offer Pending	
K47	632650453	PART OF LOT 23 CON 8 MANVERS DESIGNATED AS PARTS 1, 2, 3 & 4, 57R10329; S/T EASEMENT OVER PART 2, 57R10329 AS IN N17529; S/T EASEMENT OVER PART 3, 57R10329 AS IN MVB16650 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K48	632650314	PT LT 23-24 CON 8 MANVERS AS IN MV66710, EXCEPT PT 3 - 6, 9R2721 & PT 1, 57R8652; S/T MV53358, MVB15734, MVB16329; KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K49	632650421	LOT 1, PLAN 57M790 SUBJECT TO AN EASEMENT AS IN MVB16329 SUBJECT TO AN EASEMENT AS IN LT9925 SUBJECT TO AN EASEMENT AS IN KL34797 SUBJECT TO AN EASEMENT OVER PART 7 PL 57R9932 IN FAVOUR OF BELL CANADA AS IN KL45122 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 4, 5 & 6 PL 57R9932 AS IN KL45049 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K50	632650422	LOT 2, PLAN 57M790 SUBJECT TO AN EASEMENT AS IN MVB16329 SUBJECT TO AN EASEMENT AS IN LT9925 SUBJECT TO AN EASEMENT AS IN KL34797 SUBJECT TO AN EASEMENT OVER PART 11 PL 57R9932 IN FAVOUR OF BELL CANADA AS IN KL45122 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 8, 9 & 10 PL 57R9932 AS IN KL45049 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K51	632650423	LOT 3, PLAN 57M790 SUBJECT TO AN EASEMENT AS IN MVB16329 SUBJECT TO AN EASEMENT AS IN LT9925 SUBJECT TO AN EASEMENT AS IN KL34797 SUBJECT TO AN EASEMENT OVER PART 15 PL 57R9932 IN FAVOUR OF BELL CANADA AS IN KL45122 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 12, 13 & 14 PL 57R9932 AS IN KL45049 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K52	632650424	LOT 4, PLAN 57M790 SUBJECT TO AN EASEMENT AS IN MVB16329 SUBJECT TO AN EASEMENT AS IN LT9925 SUBJECT TO AN EASEMENT AS IN KL34797 SUBJECT TO AN EASEMENT OVER PART 19 PL 57R9932 IN FAVOUR OF BELL CANADA AS IN KL45122 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 16, 17 & 18 PL 57R9932 AS IN KL45049 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K53	632650425	LOT 5, PLAN 57M790 SUBJECT TO AN EASEMENT AS IN MVB16329 SUBJECT TO AN EASEMENT AS IN LT9925 SUBJECT TO AN EASEMENT AS IN KL34797 SUBJECT TO AN EASEMENT OVER PARTS 24 & 25 PL 57R9922 IN FAVOUR OF BELL CANADA AS IN KL45122 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 20, 21, 22, 23, & 25 PL 57R9932 AS IN KL45049 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	

	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)
K54	632650426	LOT 6, PLAN 57M790 SUBJECT TO AN EASEMENT AS IN MVB16329 SUBJECT TO AN EASEMENT AS IN LT9925 SUBJECT TO AN EASEMENT AS IN KL34797 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 26, 27 & 28 PL 57R9932 AS IN KL45049 SUBJECT TO AN EASEMENT OVER PART 29 PL 57R9932 IN FAVOUR OF BELL CANADA AS IN KL45122 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K55	632650427	LOT 7, PLAN 57M790 SUBJECT TO AN EASEMENT AS IN MVB16329 SUBJECT TO AN EASEMENT AS IN LT9925 SUBJECT TO AN EASEMENT AS IN KL34797 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 30, 31 & 32 PL 57R9932 AS IN KL45049 SUBJECT TO AN EASEMENT OVER PART 33 PL 57R9932 IN FAVOUR OF BELL CANADA AS IN KL45122 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K56	632650428	LOT 8, PLAN 57M790 SUBJECT TO AN EASEMENT AS IN MVB16329 SUBJECT TO AN EASEMENT AS IN LT9925 SUBJECT TO AN EASEMENT AS IN KL34797 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 34, 35 & 36 PL 57R9932 AS IN KL45049 SUBJECT TO AN EASEMENT OVER PART 37 PL 57R9932 IN FAVOUR OF BELL CANADA AS IN KL45122 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K57	632650429	LOT 9, PLAN 57M790 SUBJECT TO AN EASEMENT AS IN MVB16329 SUBJECT TO AN EASEMENT AS IN LT9925 SUBJECT TO AN EASEMENT AS IN KL34797 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 38, 39, 40, 41 & 43 PL 57R9932 AS IN KL45049 SUBJECT TO AN EASEMENT OVER PARTS 42 & 43 PL 57R9932 IN FAVOUR OF BELL CANADA AS IN KL45122 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K58	632650430	LOT 10, PLAN 57M790 SUBJECT TO AN EASEMENT AS IN MVB16329 SUBJECT TO AN EASEMENT AS IN LT9925 SUBJECT TO AN EASEMENT AS IN KL34797 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 44, 45 & 46 PL 57R9932 AS IN KL45049 SUBJECT TO AN EASEMENT OVER PART 47 PL 57R9932 IN FAVOUR OF BELL CANADA AS IN KL45122 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K59	632650431	LOT 11, PLAN 57M790 SUBJECT TO AN EASEMENT AS IN MVB16329 SUBJECT TO AN EASEMENT AS IN LT9925 SUBJECT TO AN EASEMENT AS IN KL34797 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 48, 49 & 50 PL 57R9932 AS IN KL45049 SUBJECT TO AN EASEMENT OVER PART 51 PL 57R9932 IN FAVOUR OF BELL CANADA AS IN KL45122 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K60	632650432	LOT 12, PLAN 57M790 SUBJECT TO AN EASEMENT AS IN MVB16329 SUBJECT TO AN EASEMENT AS IN LT9925 SUBJECT TO AN EASEMENT AS IN KL34797 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 52, 53 & 54 PL 57R9932 AS IN KL45049 SUBJECT TO AN EASEMENT OVER PT 55 PL 57R9932 IN FAVOUR OF BELL CANADA AS IN KL45122 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K61	632650433	LOT 13, PLAN 57M790 SUBJECT TO AN EASEMENT AS IN MVB16329 SUBJECT TO AN EASEMENT AS IN LT9925 SUBJECT TO AN EASEMENT AS IN KL34797 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 56, 57 & 58 PL 57R9932 AS IN KL45049 SUBJECT TO AN EASEMENT OVER PART 59 PL 57R9932 IN FAVOUR OF BELL CANADA AS IN KL45122 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K62	632650434	LOT 14, PLAN 57M790 SUBJECT TO AN EASEMENT AS IN MVB16329 SUBJECT TO AN EASEMENT AS IN LT9925 SUBJECT TO AN EASEMENT AS IN KL34797 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 60, 61 & 62 PL 57R9932 AS IN KL45049 SUBJECT TO AN EASEMENT OVER PART 63 PL 57R9932 IN FAVOUR OF BELL CANADA AS IN KL45122 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K63	632650435	LOT 15, PLAN 57M790 SUBJECT TO AN EASEMENT AS IN MVB16329 SUBJECT TO AN EASEMENT AS IN LT9925 SUBJECT TO AN EASEMENT AS IN KL34797 SUBJECT TO AN EASEMENT IN GROSS OVER PARTS 64, 65 & 66 PL 57R9932 AS IN KL45049 SUBJECT TO AN EASEMENT OVER PART 67 PL 57R9932 IN FAVOUR OF BELL CANADA AS IN KL45122 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
K64	632650466	PT LT 25 CON 8 MANVERS; S/T MVB15791, MVB15794 MVB16328, MVB16355 TOGETHER WITH AN EASEMENT OVER LOT 24, PLAN 57M790 AS IN KL114209 TOGETHER WITH AN EASEMENT OVER LOT 17 PLAN 57M790 AS IN KL123354 SUBJECT TO AN EASEMENT AS IN KL45048 TOGETHER WITH AN EASEMENT OVER LOT 28, PLAN 57M810 AS IN KL191971 CITY OF KAWARTHA LAKES	Private	Yes	Permanent Easement	Offer Pending	
SC01	267440138	PT LT 15 CON 1, CARTWRIGHT SAVE & EXCEPT PARTS 1 AND 2 PLAN 10R1707 TOWNSHIP OF SCUGOG	Private	Yes	Permanent Easement	Offer Pending	
SC02	267440119	E 1/2 LT 15 CON 1, SAVE & EXCEPT PTS 1, 2 & 3, PL 40R24788, CARTWRIGHT; S/T CA8513, CA9138; SCUGOG, REGIONAL MUNICIPALITY OF DURHAM, T/W EASEMENT OVER PT E 1/2 LT 15 CON 1, PTS 2 & 3, PL 40R24788 AS IN DR611696.	Private	Yes	Permanent Easement	Offer Pending	
SC03	267440057	PT LT 16, CON 1, CARTWRIGHT, PTS 1 TO 4, 10R1773; S/T CA8534, CA9084; SCUGOG	Private	Yes	Permanent Easement	Offer Pending	
SC04	267440059	PT LT 16, CON 1, CARTWRIGHT, AS IN N126723; S/T CA8534, CA9084 SCUGOG	Private	Yes	Permanent Easement	Offer Pending	
SC05	267440060	PT LT 17, CON 1, CARTWRIGHT, AS IN N128979; S/T CA8849, CA9137 SCUGOG	Private	Yes	Permanent Easement	Offer Pending	
SC06	267440061	PT LT 17, CON 1, CARTWRIGHT, AS IN N134974; S/T CA8563, CA9136 TOWNSHIP OF SCUGOG	Private	Yes	Permanent Easement	Offer Pending	
SC07	267440064	PT LT 18, CON 1, CARTWRIGHT, AS IN N134114; S/T CA8564, CA9135 TOWNSHIP OF SCUGOG	Private	Yes	Permanent Easement	Offer Pending	
SC08	267440063	PT LT 18, CON 1, CARTWRIGHT, AS IN N90643; S/T CA8564, CA9135 TOWNSHIP OF SCUGOG	Private	Yes	Permanent Easement	Offer Pending	
SC09	267440065	RDAL BTN LTS 18 & 19 CON 1 CARTWRIGHT BTN RDAL BTN CONS 1 & 2 CARTWRIGHT AND RDAL BTN TWPS OF CARTWRIGHT & DARLINGTON; SCUGOG	Municipal	Yes	Permanent Easement	Offer Pending	
SC10	267440066	LT 19, CON 1, CARTWRIGHT; S/T CA8513, CA9138 TOWNSHIP OF SCUGOG	Private	Yes	Permanent Easement	Offer Pending	
SC11	267440067	PT LT 20, CON 1, CARTWRIGHT, AS IN N101634; S/T CA9131, CA9323 SCUGOG	Private	Yes	Permanent Easement	Offer Pending	
SC11B	267440122	PT RDAL BTN CONS 1 & 2, CARTWRIGHT, SCUGOG, REGIONAL MUNICIPALITY OF DURHAM	Municipal	Yes	Permanent Easement	Offer Made	
SC12	267440132	PART LOT 20 CONCESSION 2, CARTWRIGHT AS IN N48910 SAVE AND EXCEPT PART 1 PLAN 40R25859 SUBJECT TO AN EASEMENT AS IN CA8506 SUBJECT TO AN EASEMENT AS IN CA9161 TOWNSHIP OF SCUGOG	Conservation Authority	Yes	Permanent Easement	Offer Pending	
SC13	267440029	LT 21, CON 2, CARTWRIGHT; S/T CA8514, CA9134 SCUGOG	Private	Yes	Permanent Easement	Offer Pending	
SC14	267440030	LT 22 CON 2, CARTWRIGHT; S/T CA8507, CA9175 SCUGOG	Conservation Authority	Yes	Permanent Easement	Offer Pending	
SC15	267440114	PT LT 23 CON 2 CARTWRIGHT AS IN N156781; S/T CA9168; S/T CA8516; SCUGOG, REGIONAL MUNICIPALITY OF DURHAM	Conservation Authority	Yes	Permanent Easement	Offer Pending	
SC16	267440130	PART LOT 23 CONCESSION 2, CARTWRIGHT, PARTS 1,2 & 3 PLAN 10R996 EXCEPT PART 1 PLAN 10R2637 AND EXCEPT PART 1 PLAN 40R25858 SUBJECT TO AN EASEMENT AS IN CA8515 SUBJECT TO AN EASEMENT AS IN CA9133 TOWNSHIP OF SCUGOG	Conservation Authority	Yes	Permanent Easement	Offer Pending	
SC17	267440123	PT LT 24 CON 2 CARTWRIGHT, PTS 4 & 5 ON PLAN 10R1313; SCUGOG, REGIONAL MUNICIPALITY OF DURHAM, S/T CA8517 & CA9132	Conservation Authority	Yes	Permanent Easement	Offer Pending	
SC18	267440037	PT LT 24 CON 2, CARTWRIGHT AS IN D514742; S/T CA8517, CA9132 TOWNSHIP OF SCUGOG	Private	Yes	Permanent Easement	Offer Pending	

	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)
SE01	284170163	PT LTS 3, 4 & 5 CON 1 (SMITH) AS IN R131726 (FIRSTLY, SECONDLY & FOURTHLY) LESS PTS 1 & 2 PL 45R8172; PT 1 PL 45R1100; PTS 1 & 2 PL 45R779; PTS 10, 12, 13 & 14 PL 45R4658; PTS 9, 10, 11 & 13 PL 45R4659; PT 1 PL 45R11720; S/T R470205, R571419, T12481, T15301, T15302, T15308, T16932, T17010, T18768 ; SMITH-ENNISMORE	Private	Yes	Permanent Easement	Offer Pending	
SE02	284170155	PT LT 5 CON 1 SMITH AS IN R568495 ; S/T R470205, R571420, T12503, T15302, T16933, T18774 SMITH-ENNISMORE	Private	Yes	Permanent Easement	Offer Pending	
SE03	284170195	PT LT 5 CON 1 SMITH & PT LT 6 CON 1 SMITH AS IN R663953 EXCEPT PTS 3 & 13 45R16219 & PT 5 45R16301 SUBJECT TO AN EASEMENT AS IN R470205 SUBJECT TO AN EASEMENT AS IN R571416 SUBJECT TO AN EASEMENT AS IN T12475 SUBJECT TO AN EASEMENT AS IN T17186 SUBJECT TO AN EASEMENT AS IN T18768 SUBJECT TO AN EASEMENT AS IN T18775 CITY OF PETERBOROUGH	Private	Yes	Permanent Easement	Offer Made	
SE04	284170160	PT LT 3 CON 1 SMITH AS IN T2508; PT LT 4 CON 1 SMITH AS IN T2509; PT LT 5 CON 1 SMITH AS IN T2502 & T3026; PT LT 6 CON 1 SMITH AS IN T2487 & T2958, EXCEPT PT 1, 45R9336 ; SMITH-ENNISMORE	Provincial	Yes	Permanent Easement	Offer Pending	
NO/LIMITED RIGHTS REQUIRED							
CL42	267420148	PT LT 15 CON 10 DARLINGTON AS IN DN4242, DN10796, DN10826; PT LT 16 CON 10 DARLINGTON AS IN DN4212, DN10796; CLARINGTON	Rail	Yes	Crossing Permit	N/A	
	267390177	RDAL BTN LT 32 & 33 CON 7 DARLINGTON; PT LT 32 CON 7 DARLINGTON AS IN N18545 & PT BEING A FORCED RD EXCEPT PTS 2-4, 10R964; S/T DN18852, DN19324; CLARINGTON	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	267390059	PT LT 35 CON 8 DARLINGTON PT 2, 10R2520; RDAL BTN CONS 7 & 8 DARLINGTON BEING REGIONAL RD 3 BTN W TOWNLINE RD & ENFIELD RD; CLARINGTON	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	267400090	PT RDAL BTN CON 8 & 9 DARLINGTON LYING SW OF N105669 & NE OF RDAL BTN TWPS OF DARLINGTON & EAST WHITBY; RDAL BTN LTS 28 & 29 CON 8 DARLINGTON N OF PT 1, 10R3679 & S OF PT CLOSED BY N105669; PT LT 29 CON 8 DARLINGTON AS IN N105669; PT LT 28 CON 8 DARLINGTON AS IN N105669; PT LT 30 CON 8 DARLINGTON PT 4, 10R3195; BEING CONCESSION RD 9 (AKA TRAVELLED RD) BTN W TOWNLINE RD & W OF PT 1 & 2, 10R3679; CLARINGTON	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	267400030	PT LT 30 CON 9 DARLINGTON AS IN DN872 & DN874; RDAL BTN LOTS 30 & 31 CON 9 DARLINGTON EXCEPT AS IN N28557, PTS 1-3 10R1222 & PT 1 10R3970, BEING ENFIELD RD; CLARINGTON	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	267400081	RDAL BTN LTS 26 & 27 CON 10 DARLINGTON BTN DEAN'S RD & TRAVELLED RD; CLARINGTON	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	267420159	RDAL BTN LTS 18 & 19 CON 9 DARLINGTON; PT LT 18 CON 9 DARLINGTON AS IN DN879; PT LT 19 CON 9 DARLINGTON PT 3, 10R407; PT LT 19 CON 9 DARLINGTON BEING A TRAVELLED RD BEING OLD SCUGOG RD; CLARINGTON	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	267410062	RDAL BTN CONS 9 & 10 DARLINGTON BEING CONCESSION RD 10 BTN SCUGOG ST & REGIONAL RD 57; CLARINGTON	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	267410056	PCL STREETS-1 SEC 10M753; SUMAC RD PL 10M753; PCL RESERVE-1 SEC 10M753; BLK 15 PL 10M753; PCL BLOCK 19-1 SEC 10M765; SUMAC RD PL 10M765 ; S/T DN18965, DN20188 CLARINGTON	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	267420150	PT LT 17 CON 10 DARLINGTON AS IN N14317 BEING REGIONAL RD 57 (AKA THE SUGOG RD) LYING S OF THE CPR; S/T DN18965, DN20335, DN22062; CLARINGTON	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	267440002	RDAL BTN TOWNSHIPS OF CARTWRIGHT & DARLINGTON BTN REGIONAL RD NO. 57 (AKA SCUGOG RD) & RDAL BTN TOWNSHIPS OF CARTWRIGHT & MANVERS ; SCUGOG	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	267440122	PT RDAL BTN CONS 1 & 2, CARTWRIGHT, SCUGOG, REGIONAL MUNICIPALITY OF DURHAM	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	267440104	RDAL BTN TOWNSHIPS OF CARTWRIGHT & MANVERS, W OF CENTRE LINE, BTN RDAL BTN CONS 2 & 3 CARTWRIGHT & RDAL BTN TOWNSHIPS OF CARTWRIGHT & DARLINGTON ; BROCK	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	632670052	FIRSTLY RDAL BTN CON 4 AND CON 5 MANVERS ABUTTING LOTS 1 TO 9 LYING W OF PT 2, 9R2140; SECONDLY PT LT 5 CON 5 MANVERS PT 2, 9R2747; KAWARTHA LAKES	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	632670101	RDAL BTN LT 5 AND LT 6 CON 5 MANVERS; KAWARTHA LAKES	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	632670095	FIRSTLY PT LT 5 CON 5 MANVERS AS IN MV34181; PT RDAL BTN CON 5 AND CON 6 MANVERS ABUTTING LOTS 1 TO 10; SECONDLY PT LT 4 CON 5 MANVERS BEING A FORCED RD AKA BALLYDUFF RD, AKA MAIN ST LYING BTN MANVERS - SCUGOG TOWNLINE & HWY NO. 35; KAWARTHA LAKES	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	632660125	RDAL BTN LT 10 AND LT 11 CON 4 MANVERS; RDAL BTN LT 10 AND LT 11 CON 5 MANVERS; RDAL BTN LT 10 AND LT 11 CON 6 MANVERS; RDAL BTN LT 10 AND LT 11 CON 7 MANVERS; RDAL BTN CON 3 AND CON 4 MANVERS; RDAL BTN CON 4 AND CON 5 MANVERS; RDAL BTN CON 5 AND CON 6 MANVERS; RDAL BTN CON 6 AND CON 7 MANVERS; PT LT 10 CON 4 MANVERS; PT LT 10 CON 6 MANVERS; PT LT 10 CON 7 MANVERS; PT LT 11 CON 4 MANVERS; PT LT 11 CON 5 MANVERS; PT LT 11 CON 6 MANVERS; PT LT 11 CON 7 MANVERS AS IN HWYM86 EXCEPT PT 3 & 4, HWYM158; PT LT 10 CON 4 MANVERS PT LT 11 CON 4 MANVERS AS IN HWYM75 EXCEPT MV30671; PT LT 11 CON 4 MANVERS AS IN HWYM73; PT LT 11 CON 5 MANVERS AS IN MVC2315, HWYM87; PT LT 10 CON 6 MANVERS; PT LT 11 CON 6 MANVERS AS IN HWYM74; PT LT 10 CON 7 MANVERS; PT LT 11 CON 7 MANVERS AS IN HWYM68 BTN RDAL CON 7 AND CON 8 MANVERS AND RDAL CON 3 AND CON 4 MANVERS BEING KING'S HIGHWAY NO. 35; S/T MVB15715, MVB15717, MVB16252, MVB16364, MVB16365; KAWARTHA LAKES	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	632660147	RDAL BTN CON 6 AND CON 7 MANVERS BTN E LIMIT OF HWYM86 AND W LIMIT OF 57R7209; KAWARTHA LAKES	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	632660146	RDAL BTN LT 15 AND LT 16 CON 7 MANVERS S OF HWYM126; KAWARTHA LAKES	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	

	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)
	632650137	PT RDAL BTN CON 7 AND CON 8 MANVERS E OF HWY 35; PT RDAL BTN LT 15 AND LT 16 CON 7 MANVERS; PT RDAL BTN LT 20 AND LT 21 CON 7 MANVERS; PT RDAL BTN LT 20 AND LT 21 CON 8 MANVERS W OF THE CENTRELINE; PT RDAL BTN TWP OF CAVAN AND TWP OF MANVERS; PT LT 12-25 CON 7 MANVERS; PT LT 11-15, 17-18, 20-25 CON 8 MANVERS, PT LT 5 PL 4 MANVERS AS IN HWYM126, HWYM51, HWYM88, HWYM90, HWYM95, HWYM106, HWYM107, HWYM108, HWYM111, HWYM119, HWYM121, HWYM122, HWYM148 PT 2 & HWYM127, AS IN HWYM49 EXCEPT HWYM56, MV83855 & MV56887, AS IN HWYM84 EXCEPT 9R178, AS IN HWYM118 EXCEPT 9R2183, & AS IN HWYM109 EXCEPT MV87324; AKA HWY #7A; T/W EASEMENT OVER PT LT 23 CON 8 MANVERS DESIGNATED PART 1 PL 57R9585, AS IN KL24885 CITY OF KAWARTHA LAKES	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	632650403	FIRSTLY: LT 11 N/S GEORGE ST PL 5 MANVERS; PT LT 8 N/S KING ST, 9 S/S GEORGE ST, 10 N/S GEORGE ST, 21-23 PL 5 MANVERS; PT GEORGE ST, JACKSON ST, AGNES ST PL 5 MANVERS CLOSED BY BL60; PT LT 23-24 CON 8 MANVERS AS IN MVB3773, PT 1 - 4 57R6818, PT 2 9R653, PT 1 - 4 9R1810, PT 2 9R2273, PT 1 - 11 9R2721 & PT 1 9R2010; SECONDLY: PT LT 24 CON 8 MANVERS PT 1 9R284; AKA COUNTY RD 38 AKA SKI HILL RD; S/T MV53355, MV53358, MVB15734, MVB16329; KAWARTHA LAKES	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	632650409	BLK B PL 157 MANVERS; RDAL BTN TWP OF CAVAN AND TWP OF MANVERS W OF CENTRELINE BTN HWY 7A & RDAL BTN CON 10 & 11; KAWARTHA LAKES	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	280020259	FIRSTLY; PT RDAL BTN CON 10 & CON 11 CAVAN BTN TWP OF MANVERS & RDAL BTN LOTS 12 & 13 CAVAN; SECONDLY; PT LT 4 CON 10 CAVAN PT 1 & 2 9R2361 WEST OF PART 3 PLAN 45R16106 TOWNSHIP OF CAVAN-MONAGHAN	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	280020262	PART LOT 7 CON 11 CAVAN BTN CMR15253, CMR19072 & R656744 BEING FORCED RD EXCEPT PART 2 PLAN 45R16106 TOWNSHIP OF CAVAN-MONAGHAN	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	280030001	FIRSTLY: RDAL BTN CON 9 & CON 10 CAVAN; RDAL BTN LOTS 12 & 13 CON 10 CAVAN; RDAL BTN CON 10 & CON 11 CAVAN; RDAL BTN LOTS 12 & 13 CON 11 CAVAN; PT LT 13 CON 10 CAVAN PT 1, 2 & 3 45R10664; SECONDLY: PT LT 12 CON 10 CAVAN AS IN CMR8741, CVNC4280 & CVNC3885 EXCEPT PT 1 9R306; PT LT 13 CON 10 CAVAN AS IN CMR9032; PT LT 12-13 CON 11 CAVAN AS IN CMR8744 & CMR17820, CMR11095; BEING COUNTY RD #10 LYING NORTH OF RDAL BTN CON 10 & CON 9 CAVAN AND SOUTH OF RDAL BTN CON 11 & 12 CAVAN; S/T CVNC3385, CVNC4336, CVNC4829; CVN-MIL-NMO	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	280000434	RDAL BTN CON 11 & CON 12 CAVAN ABUTTING LOTS 13 TO 23 AKA STEWART 12TH LINE; CVN-MIL-NMO	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	280000440	RDAL BTN LOTS 18 & 19 CON 12 CAVAN; CVN-MIL-NMO	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	280000435	RDAL BTN CON 12 & CON 13 CAVAN ABUTTING LOTS 13 TO 23 AKA HOOTON DR; CVN-MIL-NMO	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	280000436	FIRSTLY: RDAL BTN CON 13 & CON 14 CAVAN; PT LT 13-15, 23 CON 13 CAVAN; PT LT 20, 22 CON 13 CAVAN; PT LT 13-15 CON 14 CAVAN PT 1-7 9R226, PT 1 9R2779, PT 12, 23, 24 9R807; SECONDLY: PT LT 16 CON 13 CAVAN; PT LT 17-22 CON 13 CAVAN; PT LT 20-22 CON 14 CAVAN PT 1-11, 13-17, 20-22 9R807; PT LT 23 CON 13 (TRAVELLED RD) AKA KING ST, COUNTY RD 9, COUNTY RD 55 BTN QUEEN ST & PRESTON RD; S/T CVNC4351, CVNC4445, CVNC4802, CVNC4833, CVNC5190, CVNC5211; CVN-MIL-NMO	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	280370189	PT RDAL BTN TWP OF NORTH MONAGHAN & CAVAN NORTH MONAGHAN LYING BTN SHERBROOKE ST & PARKHILL RD, AKA HWY #133; AKA TRANS-CANADA HWY; PT W 1/2 LT 1 CON 13 NORTH MONAGHAN AS IN R77777, R84185, R87413, R88370, EXCEPT PT 5 PL 45R11411; PT LT 23 CON 14 CAVAN A	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	267390197	PART LOT 32 CONCESSION 8 AND PART ROAD ALLOWANCE BETWEEN LOTS 32 & 33 CONCESSION 8 DARLINGTON, PARTS 1, 2, 3, 4, 5 & 6 40R31093; SUBJECT TO AN EASEMENT OVER PARTS 1 & 5 40R31093 AS IN DN19438; SUBJECT TO AN EASEMENT OVER PART 3 40R31093 AS IN DN18735; TOGETHER WITH AN EASEMENT AS IN N44310; MUNICIPALITY OF CLARINGTON	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	284170002	PT RDAL BTN TWP OF N MONAGHAN & SMITH SMITH BEING PARKHILL RD LYING BTN HWY 7 & BREALEY DR; PT LT 1 CON 1 SMITH PT 15, 45R4659; PT LT 2 CON 1 SMITH PT 14, 45R4659; PT LT 3 CON 1 SMITH PTS 9 TO 13, 45R4659; PT LT 4 CON 1 SMITH PTS 9 TO 14 45R4658; PT LT 4 CON 13 N MONAGHAN PT 1, 45R4658; PT LT 5 CON 1 SMITH PTS 7 & 8, 45R4658; PT LT 5 CON 13 N MONAGHAN PT 2, 45R4658; PT LT 6 CON 13 N MONAGHAN PTS 3 & 5, 45R4658, PT 5, 45R2329 & AS IN R244295, LYING W OF BREALEY DR; PT LT 6 CON 1 SMITH PT 6, 45R4658; PT LT 1 CON 13 N MONAGHAN; PT LT 2 CON 13 N MONAGHAN; PT LT 3 CON 13 N MONAGHAN PTS 1 TO 8, 45R4659; SMITH-ENNISMORE	Road Allowance	No	Rely on Section 41.1 (1) of the Electricity Act	N/A	
	267390027	PT LT 34 CON 7 DARLINGTON; PT LT 35 CON 7 DARLINGTON; PT RDAL BTN LTS 34 & 35 CON 7 DARLINGTON PTS 1-10, EXPROP PL N88184, PT 2, 10R1018 & AS IN N96793 EXCEPT PT 1, 10R1185, PTS 1, 2 & 6, EXPROP PL N88184; S/T DN16830, DN16831, DN16832, DN19264, DN19293; CLARINGTON	Hydro One Owned	No	None	N/A	
	284170159	PT LT 6 CON 1 SMITH AS IN T15485 LYING N OF RAILWAY, EXCEPT PTS 6 & 7, 45R5966; S/T R462616, T15496 SMITH-ENNISMORE	Hydro One Owned	No	None	N/A	
	284170157	PT LT 6 CON 1 SMITH AS IN T15485 LYING S OF RAILWAY; S/T R462616, T15496 SMITH-ENNISMORE	Hydro One Owned	No	None	N/A	

EARLY ACCESS AGREEMENT

THIS AGREEMENT made in duplicate the _____ day of _____ 202__

Between:

«ALL_ OWNERS»

(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 «PIN» (LT), (the “Lands”).

WHEREAS HONI in connection with the Durham Kawartha Power Line 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 in accordance with the option selected by the Grantor below:

(i)

The Initial Term commences on the Agreement date written above.

Grantor Initials for Option 2(i): _____

(ii)

The Initial Term commences on December 1, 2024 or earlier as agreed upon between HONI and Grantor.

Grantor Initials for Option 2(ii): _____
- Page 1 of 4
- HONI FILE NO.:
- Page 2 of 5

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:

«ALL_OWNERS»
Address: «MAILING_ADDRESS»

Attention:
Tel: «PHONE»

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, 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

«OWNER_1»

SIGNED, SEALED AND DELIVERED

In the presence of

)

)

)

)

)

)

(seal)

Print Name of Witness

«OWNER_2»

SIGNED, SEALED AND DELIVERED

In the presence of

)

)

)

)

)

)

(seal)

Print Name of Witness

«OWNER_3»

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:

«ALL_OWNERS»

(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. **GRANT OF OPTION**

In consideration of the sum of **«OPTION_PAYMENT_WORDS»** (**«Option_Payment»**) 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. **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 **«EASEMENT_PAYMENT_WORDS»** (**«Easement_Payment»**) 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:

Name:

Address:

Name: «**OWNER_1**»
1/s

Name:

Address:

Name: «**OWNER_2**»
1/s

Name:

Address:

Name: «**OWNER_3**»
1/s

WITNESS:

The spouse of the Owner hereby consents to this Agreement

SPOUSE OF OWNER:

Name:

Address:

Name:
1/s

Per: _____
Name:
Title:

We/I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: _____
Name:
Title:

I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: _____
Name:
Title:

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.**

**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 \$XXXX 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:	with a copy to its solicitors,
Hydro One Networks Inc.	Barriston LLP
Facilities and Real Estate	90 Mulcaster Street
P.O. Box 4300	Barrie, ON L4M 4Y5
Markham, Ontario L2R 5Z5	
185 Clegg Road	Attention: Jim McIntosh
Markham, Ontario L3G 1B7	Fax: 705-721-4025
Attention: Real Estate Manager	
Fax: (905) 946-6242	

OWNER: with a copy to their solicitors,

«ALL_OWNERS»

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.

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

«**ALL OWNERS**» (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:

	1/s
Name:	Name: «OWNER_1»
Address:	

	1/s
Name:	Name: «OWNER_2»
Address:	

	1/s
Name:	Name: «OWNER_3»
Address:	

WITNESS:

The spouse of the Owner hereby consents to this Acknowledgement and Direction

SPOUSE OF OWNER:

Name:

Name: **Property Owner Spouse Name**

1/s

XXXXXXXXXXXXXXXXXXXX

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:

«**ALL OWNERS**»

(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 October 1, 2025 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 Purchase Price, Premium Above Fair Market Value, and the IA compensation, if applicable 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 «OPTION_PAYMENT_WORDS» (**«Option_Payment»**) 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 «ACCEPTANCE_WORDS» (**«Acceptance_Incentive»**), (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 «PREMIUM_WORDS» (**«Premium_Above_Market_Value»**), (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 «**IA_WORDS**» («**IA**») 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:

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 Street
Barrie, ON L4M 4Y5

185 Clegg Road
Markham, Ontario L3G 1B7

Attention: Jim McIntosh
Fax: 705-721-4025

Attention: Real Estate Manager
Fax: (905) 946-6242

OWNER:

with a copy to their solicitors,

«**ALL_OWNERS**»

Phone Number:
Email:

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. 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:

Name:

Address:

Name: «OWNER_1»
1/s

Name:

Address:

Name: «OWNER_2»
1/s

Name:

Address:

Name: «OWNER_3»
1/s

WITNESS:

The spouse of the Owner hereby consents to this Compensation and Incentive Agreement

SPOUSE OF OWNER:

Name:

Address:

Name:
1/s

Per: _____
Name:
Title:

We/I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: _____
Name:
Title:

I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: _____
Name:
Title:

I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: _____
Name:
Title:

I have authority to bind the Corporation

SCHEDULE “A”
LANDS

SCHEDULE “B”
CALCULATION SHEET

OPTION TO PURCHASE – 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:

Name: «Real_Estate_Representative»

Address: 1800 Main Street East
Milton, ON L9T 7S3

Name: «Owner_1_name_for_letters»

1/s

Name: «Real_Estate_Representative»

Address: 1800 Main Street East
Milton, ON L9T 7S3

Name: «Owner_2_name_for_letters»

1/s

Name: «Real_Estate_Representative»

Address: 1800 Main Street East
Milton, ON L9T 7S3

Name: «Owner_3_name_for_letters»

1/s

WITNESS:

The spouse of the Owner hereby consents to this Agreement

SPOUSE OF OWNER:

Name: Real Estate Representative

Address: 1800 Main Street East
Milton, ON L9T 7S3

Name: **Property Owner Spouse Name**

1/s

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: _____
Name:
Title:

I have authority to bind the Corporation

**SCHEDULE “A”
LEGAL DESCRIPTION**

«LEGAL_DESCRIPTION»

**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 \$XXXXXX 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. SURVEY/REFERENCE PLAN

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. 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)*.

10. HARMONIZED SALES TAX

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. 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.

12. 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 Corridor Lands prior to the registration of the Closing of the transaction contemplated herein without the prior written consent of Hydro One.

13. 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 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. 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.

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:	with a copy to its solicitors,
Hydro One Networks Inc.	Barriston LLP
Facilities and Real Estate	90 Mulcaster Street
P.O. Box 4300	Barrie, ON L4M 4Y5
Markham, Ontario	
L2R 5Z5	
	Attention: Jim McIntosh
185 Clegg Road	Fax: (705)-721-4025
Markham, Ontario	
L3G 1B7	
Attention:	
Fax:	(905) 946-6242

OWNER:	with a copy to their solicitors,
«Owner_1_name_for_letters»	Solicitors Name
«Owner_2_name_for_letters»	Solicitors Address 1
«Owner_3_name_for_letters»	Solicitors Address 2
«STREET_NUM» «STREET_NAME1»	Solicitors Address 3
«MUNICIPALITY», «PROVINCE»	
«POSTAL_CODE»	
«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.

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.13 and 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:

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 St
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 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:

Name: «Real_Estate_Representative»

Address: 1800 Main Street East
Milton, ON L9T 7S3

OWNER:

1/s

Name: «Owner_1_name_for_letters»

Name: «Real_Estate_Representative»

Address: 1800 Main Street East
Milton, ON L9T 7S3

1/s

Name: «Owner_2_name_for_letters»

Name: «Real_Estate_Representative»

Address: 1800 Main Street East
Milton, ON L9T 7S3

1/s

Name: «Owner_3_name_for_letters»

WITNESS:

The spouse of the Owner hereby consents to this Agreement

Name: Real Estate Representative

Address: 1800 Main Street East
Milton, ON L9T 7S3

SPOUSE OF OWNER:

1/s

Name: **Property Owner Spouse Name**

HYDRO ONE
HST 870865821RT0001

HYDRO ONE NETWORKS INC.

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 October 1st, 2021 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 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, and the IA Compensation, if applicable.

- (c) The actual area of the Corridor Lands will be confirmed by a survey to be prepared by Hydro One and in the event the surveyed area of the Corridor Lands is greater than as provided for in the Calculation Sheet, the Purchase Price, and the IA compensation, if applicable will be adjusted accordingly.

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.

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:	with a copy to its solicitors,
Hydro One Networks Inc.	Barriston LLP
Facilities and Real Estate	90 Mulcaster Street
P.O. Box 4300	Barrie, ON L4M 4Y5
Markham, Ontario L2R 5Z5	
	Attention: Jim McIntosh
185 Clegg Road	Fax: 705-721-4025
Markham, Ontario L3G 1B7	
Attention:	
Fax: (905) 946-6242	

OWNER:	with a copy to their solicitors,
«Owner_1_name_for_letters» &	Solicitors Name
«Owner_2_name_for_letters» &	Solicitors Address 1
«Owner_3_name_for_letters»	Solicitors Address 2
«STREET_NUM» «STREET_NAME1»	Solicitors Address 3
«MUNICIPALITY», «PROVINCE»	
«POSTAL_CODE»	
«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 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:
	1/s
Name: «Real_Estate_Representative»	Name: «Owner_1_name_for_letters»
Address: 1800 Main Street East Milton, ON L9T 7S3	
	1/s
Name: «Real_Estate_Representative»	Name: «Owner_2_name_for_letters»
Address: 1800 Main Street East Milton, ON L9T 7S3	
	1/s
Name: «Real_Estate_Representative»	Name: «Owner_3_name_for_letters»
Address: 1800 Main Street East Milton, ON L9T 7S3	

WITNESS:	The spouse of the Owner hereby consents to this Compensation and Incentive Agreement
	SPOUSE OF OWNER:
	1/s
Name: «Real_Estate_Representative»	Name: Property Owner Spouse Name
Address: 1800 Main Street East Milton, ON L9T 7S3	

HYDRO ONE NETWORKS INC.	
	Per:
HYDRO ONE	Name:
HST 870865821RT0001	Title:
	I have authority to bind the Corporation

SCHEDULE “A”
LANDS

«LEGAL_DESCRIPTION»

SCHEDULE “B”
CALCULATION SHEET

AGREEMENT FOR TEMPORARY RIGHTS

Material Laydown Area

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 SUBJECT 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.

Material Laydown Area

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 7S3

Attention:
Tel:

TO GRANTOR:

XXXXXXXX
XXXXXXXX
XXXXXXXX

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 (5th) 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.

Material Laydown Area

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:

XXXXXXXXXX

(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:

XXXXXXXXXX
XXXXXXXXXX

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 (5th) 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

SIGNED, SEALED & DELIVERED
In the presence of:

Witness

OWNER(S):

Name:

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

CROP LAND OUT OF PRODUCTION AGREEMENT

CROPLAND OUT-OF-PRODUCTION FOR 20XX-20XX CROP GROWING SEASON

FULL AND FINAL RELEASE

WHEREAS XXXXX is/are the owner(s) (collectively the “Owner”) of the lands legally described as XXXXXX being PIN XXXXXX (LT) (the “Property”).

AND WHEREAS Hydro One Networks Inc. (“Hydro One”) has entered into an Early Access Agreement with the Owner to carry out activities, in, on, over, under, across and through a portion of the Property, which shall be used for the purposes of Hydro One’s new Durham Kawartha Power Line Project (the “Line”).

AND WHEREAS The Property is used for agricultural purpose and as a consequence of the early access activities on the Property, parts of the Property may be out of production for the 20XX and 20XX crop growing season and Hydro One is agreeable in compensating the Owner the amount of \$XX,XXX plus HST, if applicable, for the loss of crop lands for the 20XX and 20XX growing season (the “Crop Compensation Amount”).

NOW THEREFORE in consideration of the payment of the Crop Compensation Amount by Hydro One to the Owner and for other good and valuable consideration the receipt and sufficiency of which is hereby acknowledged, the Owner and Hydro One hereby agree as follows:

EACH OF THE UNDERSIGNED, on behalf of himself/herself, his/her heirs, executors, administrators, successors and assigns (hereinafter the “Releasors”), hereby releases and forever discharges Hydro One and its respective officers, directors, employees, servants and agents and its parent, affiliates, subsidiaries, and their respective successors and assigns (hereinafter collectively the “Releasee”) jointly and severally from any and all actions, causes of action, claims and demands for damages, indemnity, costs, interest and loss or injury of every nature and kind whatsoever, howsoever arising, which the Releasors now have, may have had or may hereafter have arising from or in any way related to or as a result of crop land being out of production for the 20XX and 20XX crop growing season on the Property resulting from the early access activities on the Property.

THE RELEASORS acknowledge that the Crop Compensation Amount was calculated in accordance with the Pre-Construction Cropland Out-Of-Production Payment set out in the Cropland Out-of-Production Booklet, which calculations are set out in Schedule “A” and elected by the Releasors. The Cropland Out-of-Production Booklet is attached hereto as “Schedule B”.

THE RELEASORS agree that the effective date of this full and final release shall be the date that the Crop Compensation Amount is paid by Hydro One to the Releasors. The Crop Compensation Amount will be paid to the Releasors by Hydro One within 60 business days of the date of this agreement.

AND FOR THE SAID CONSIDERATION, the Releasors further agree not to make any claim or take any proceedings against any other person or corporation who might claim contribution or indemnity under the provisions of the *Negligence Act* and the amendments thereto from the persons or corporations discharged by the release.

AND THE RELEASORS hereby confirm and acknowledge that the Releasors have sought or declined to seek independent legal advice before signing this Release, that the terms of this Release are fully understood, and that the said amounts and benefits are being accepted voluntarily, and not under duress, and in full and final compromise, adjustment and settlement of all claims against the Releasees.

IT IS UNDERSTOOD AND AGREED that the said payment or promise of payment is deemed to be no admission whatsoever of liability on the part of the Releasees.

AND IT IS UNDERSTOOD AND AGREED that this Release may be executed in separate counterparts (and may be transmitted by email) each of which shall be deemed to be an original and that such counterparts shall together constitute one and the same instrument, notwithstanding the date of actual execution.

IN WITNESS WHEREOF, the Releasors have hereunto set their respective hands this _____ day of _____, 20__.

SIGNED, SEALED AND DELIVERED

In the presence of)
)
)
)
)

_____) (seal)
Print Name of Witness

)
)
)
)
)
_____) (seal)
Print Name of Witness

)
)
)
)
)
_____) (seal)
Print Name of Witness

Per: _____

Print Name:

Print Title:

Per: _____

Print Name:

Print Title:

We/I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

Per: _____

Name:

Title: **Real Estate Services Supervisor**

I have authority to bind the Corporation

SCHEDULE "A"

Crop Compensation Amount was calculated as follows:

File Number:	XX
Number of Arable Acres:	X.XX
Rate Per Acre:	\$X,XXX.XX

Cropland Out-of-Production Payment Schedule:

Cropland Out-of-Production Payable :

HST Payable:	<u>\$ X,XXX</u>
Total Cropland Out-of-Production Payable:	<u><u>\$X,XXX</u></u>

SCHEDULE “B”

*Cropland Out-of-Production Booklet

DAMAGE CLAIM AGREEMENT/WAIVER

Damage Claim

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: XXXXXXXX (\$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 Final SIA prepared by the IESO (SIA reference # CAA 2024-823).

The Final 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 the SIA are implemented.

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

Filed: 2026-06-12
EB-2026-0155
Exhibit F
Tab 1
Schedule 1
Page 2 of 2

1

This page has been left blank intentionally.

FINAL IESO SYSTEM IMPACT ASSESSMENT



System Impact Assessment Report

Final Report - Public

CAA ID: 2024-823

Project: Durham Kawartha Power Line and Dobbin TS
Autotransformer Replacement

Connection Applicant: Hydro One Networks Inc.

April 14, 2026



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.



Table of Contents

Acknowledgement	1
Disclaimers	2
IESO	2
Hydro One	3
Project Description	5
Notification of Conditional Approval	5
Assessment Findings	6
IESO Requirements for Connection	6
Specific Requirements:	6
Requirements for the Connection Applicant and Transmitter	6
General Requirements:	7
Recommendation	7
Appendix A: General Requirements	8
Appendix B: Project Data (Confidential)	11
Appendix C: Facility Classification (Confidential)	11
Appendix D: Study Scope of Work (Confidential)	11
Appendix E: Detailed Study Results (Confidential)	11

Project Description

Hydro One Networks Inc. (the “connection applicant” and the “transmitter”) is planning to build the Durham Kawartha Power Line, a new 230 kV double-circuit lines, named T40P and T41P, spanning 55 km between Clarington Transformer Station (TS) and Dobbin TS, to improve system reliability and meet long term capacity needs in the East region; while concurrently undertaking sustainment work at Dobbin TS to replace End of Life (EOL) Autotransformers (the “project”).

The Durham Kawartha Power Line development project includes the following:

- At Clarington TS:
 - Disconnection of the existing 230kV circuit T28C from Seaton Junction (Jct) to outside Clarington TS, and terminating T40P in its place,
 - Addition of one new two-breaker-diameter (breakers K1L41, and P1L41) at Clarington TS to allow termination of the new T41P circuit.
- At Dobbin TS
 - Termination of the new line T41P in the existing C27P position, re-termination of the existing line C27P in the existing P15C circuit position, and termination of the new line T40P in the existing X1P position,
 - Addition of one new three-breaker-diameter (breakers AL15, L1L15, and HL1) and re-termination of the existing lines X1P and P15C into this new diameter,
 - Due to increased short circuit levels at Dobbin TS 44kV bus, the 44kV bus-tie breaker BY will operate normally open when transformers T3 and T4 are in service. When either T3 or T4 is out of service, the 44kV BY bus tie breaker will be closed so that all station load, as well as station service SS1 and SS2, are energized. The five existing 230kV circuit breakers will be replaced with new breakers of higher short circuit rating.

The EOL sustainment work at Dobbin TS involves:

- The existing autotransformers T1 and T5 will be replaced (renaming T1 as T7 and T5 as T8), and the existing autotransformer T2 will be decommissioned.

The proposed in-service date of the project is Q4, 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 the reliability of the IESO-controlled grid, in line with applicable reliability standards. 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 assessment findings:

1. Under summer conditions, the continued load growth at Dobbin TS and across the Dobbin Area¹ exacerbates thermal overloads above the Short-Term Emergency (STE) rating on the 230 kV circuit P15C under the following contingencies:
 - a. A shared tower contingency involving the two new 230 kV circuits T40P and T41P.
 - b. An outage to T40P followed by a contingency on T41P, or an outage to T41P followed by a contingency on T40P.

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 Transmitter

1. To address Finding #1, the connection applicant shall modify the Dobbin Remedial Action Scheme (RAS) according to the details in Appendix E.

During the IESO Market Registration process, a revised FDD for the Dobbin RAS must be provided and finalized at least nine months prior to in-service. The FDD must contain the finalized RAS matrix as well as expected operating times. The actual operating times must be measured during commissioning and documented as a Performance Validation Record.

If the FDD or performance testing as per the Performance Validation Record indicates a change in design or slower than expected operating times, as compared to what was assumed in this assessment, then further analysis of the project will need to be done by the IESO. This may delay the grant of IESO final approval to place the project in-service.

Preliminarily IESO studies indicate that the Dobbin RAS will qualify as a Limited Impact RAS subject to approval by NPCC. To avoid any delay to the project, it is strongly recommended the RAS facilities be designed to meet NPCC Reliability Reference Directory #7 for NPCC Type I RAS before the RAS type classification is finalized via the NPCC RAS approval process. If approved to be a Limited Impact RAS by the approval process, the connection applicant still shall ensure the RAS facilities

¹ Defined in Appendix D

have provisions to comply with NPCC Reliability Reference Directory #7 for Type I RAS in case the RAS is re-classified as such in the future as the system evolves.

Telemetry, as specified by the IESO at the time of registration, shall be provided.

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 Transmission 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 project's equipment meet the voltage requirements specified in section 2.4.2 and section 2.4.3 of the Ontario Resource and Transmission Assessment Criteria (ORTAC).
4. 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/switchers 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.

5. 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.

6. 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.
7. 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.
8. 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.

9. 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

10. The Ontario Resource and Transmission Assessment Criteria (ORTAC) states that the transmission system must be planned such that, following design criteria contingencies on the transmission system, affected loads can be restored with the restoration times listed below:
 - All load must be restored within approximately a target of 8 hours;
 - When the amount of load interrupted is greater than 150MW, the amount of load in excess of 150MW must be restored within approximately a target of 4 hours;
 - When the amount of load interrupted is greater than 250MW, the amount of load in excess of 250MW must be restored within a target of 30 minutes.
11. 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.



Appendix B: Project Data (Confidential)

Appendix C: Facility Classification (Confidential)

Appendix D: Study Scope of Work (Confidential)

Appendix E: Detailed Study Results (Confidential)

**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](https://twitter.com/IESO)



facebook.com/OntarioIESO



linkedin.com/company/IESO

CUSTOMER IMPACT ASSESSMENT

Please refer to **Attachment 1** of this Schedule for the Final CIA prepared by Hydro One.

The Final CIA concludes that the Project is expected to have no material adverse impact on the reliability of the transmission connected customers in the area, provided that all requirements in the CIA are implemented.

This page has been left blank intentionally.

FINAL CUSTOMER IMPACT ASSESSMENT



Hydro One Networks Inc.

483 Bay Street

Toronto, Ontario

M5G 2P5

CUSTOMER IMPACT ASSESSMENT

DURHAM KAWARTHA POWER LINE AND DOBBIN TS AUTOTRANSFORMER REPLACEMENT PROJECT

CIA ID: 2026-04
Revision: Final
Date: 22nd April 2026

Issued by:
System Planning Division
Hydro One Networks Inc.

Prepared by:

A handwritten signature in black ink, appearing to read "Sorabh", written over a horizontal line.

Sorabh Devgun
Assistant Network Management Officer
System Planning Division
Hydro One Networks Inc.

Approved by:

A handwritten signature in black ink, appearing to read "Ajay", written over a horizontal line.

Ajay Garg
Manager - Transmission Planning
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.

TABLE OF CONTENT

1.0	Introduction	4
1.1	<i>Purpose.....</i>	<i>4</i>
1.2	<i>Background</i>	<i>4</i>
1.3	<i>Connected Customers</i>	<i>7</i>
2.0	Customer Impact Assessment.....	8
2.1	<i>Load Flow Study.....</i>	<i>8</i>
2.2	<i>Thermal Loading</i>	<i>8</i>
2.3	<i>Voltage Performance.....</i>	<i>9</i>
2.4	<i>Short Circuit Study.....</i>	<i>9</i>
2.5	<i>Customer Reliability.....</i>	<i>10</i>
3.0	Conclusion	10
	Appendix A: Load Flow Studies	12
	Appendix B: Short Circuit Study	15

CUSTOMER IMPACT ASSESSMENT

DURHAM KAWARTHA POWER LINE AND DOBBIN TS AUTOTRANSFORMER REPLACEMENT

1.0 INTRODUCTION

1.1 Purpose

This Customer Impact Assessment (CIA) study assesses the potential impact of connection of 2x 230 kV double-circuit transmission line that will span from the existing Clarington TS to the existing Dobbin TS and disconnection of idle 230 kV T28C circuit from Seaton Jct. to Clarington TS also referred to herein as the Durham Kawartha Power Line (“the Project”). Due to the connection of the new line to Dobbin TS, 5 existing 230kV breakers are to be replaced with new breakers that have a higher rating, as well as opening the 44kV bus tie at Dobbin TS.

In addition, this CIA also accesses the end-of-life Autotransformer replacements at Dobbin TS. This study is in accordance with section 6 of the Ontario Energy Board’s Transmission System Code (“TSC”), which requires Hydro One Networks Inc. (Hydro One) to carry out a CIA study to assess the impact of the proposed project on existing transmission connected customers in the affected area.

This assessment does not evaluate the overall impact of the project on the bulk electricity system. As part of the Connection Assessment and Approval (“CAA”) process, impact of this project on the bulk electricity system is the subject of the System Impact Assessment (“SIA”), which is carried out by the Independent Electricity System Operator (“IESO”). The IESO has documented their findings for the project in their SIA report CAA ID 2024-823, dated April 14th, 2026.

1.2 Background

Hydro One Networks Inc. is planning to build new 230 kV double circuit lines, named T40P and T41P, spanning approximately 55 km between Clarington TS and Dobbin TS, retiring T28C from Seaton Jct to Clarington TS (new name C28), and accompanying station work at Clarington TS and Dobbin TS to improve system reliability and meet long term capacity needs in the East region. The proposed Project forms part of the bulk transmission system reinforcement required to address emerging constraints and support forecast load growth in Eastern Ontario. The proposed in-service date for this project is December 2029.

Figures 1 and 2 show the single-line diagram of the project and the geographical location of the project, respectively.

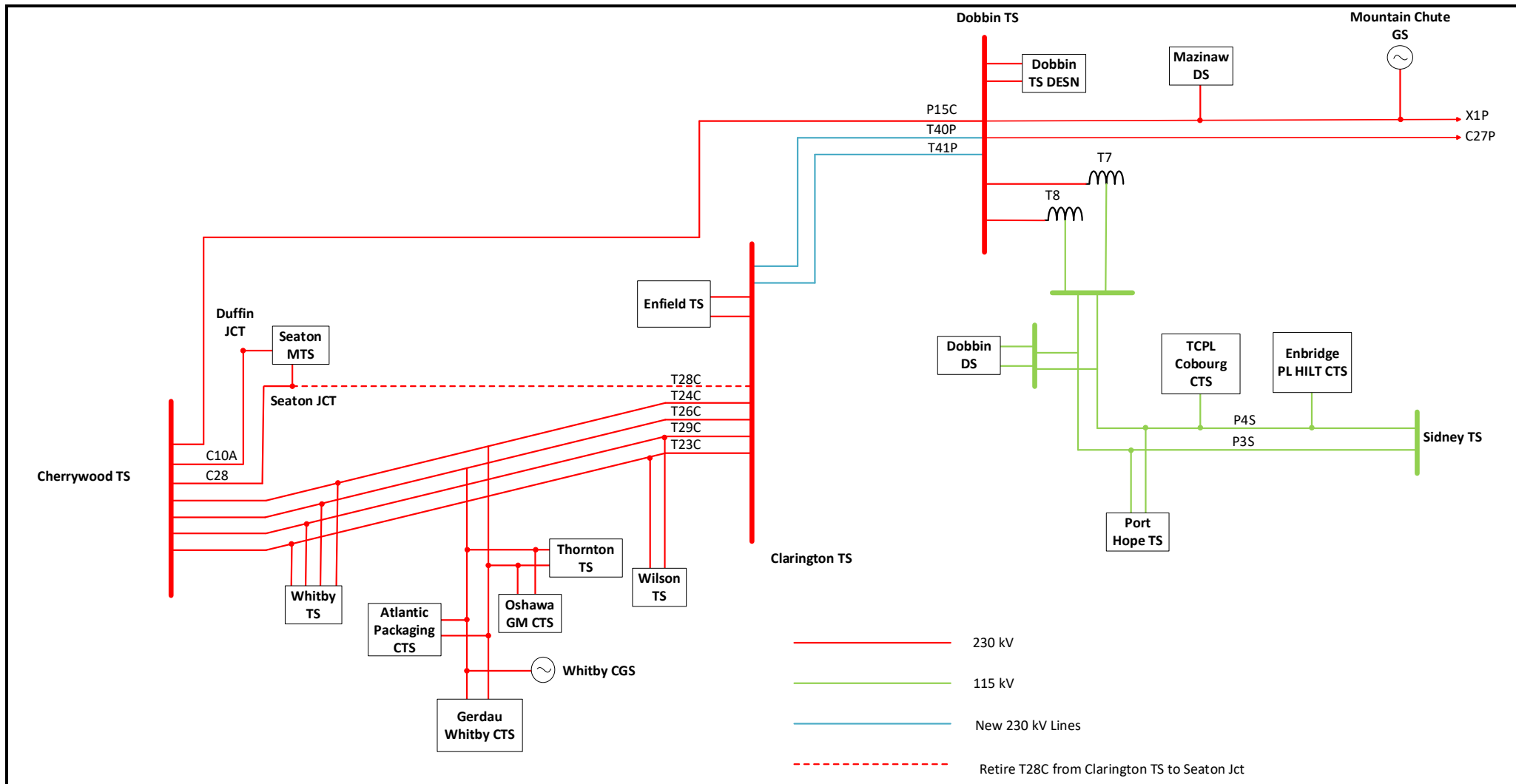


Figure 1: Single line diagram of Durham Kawartha Power Line Project and surrounding region.

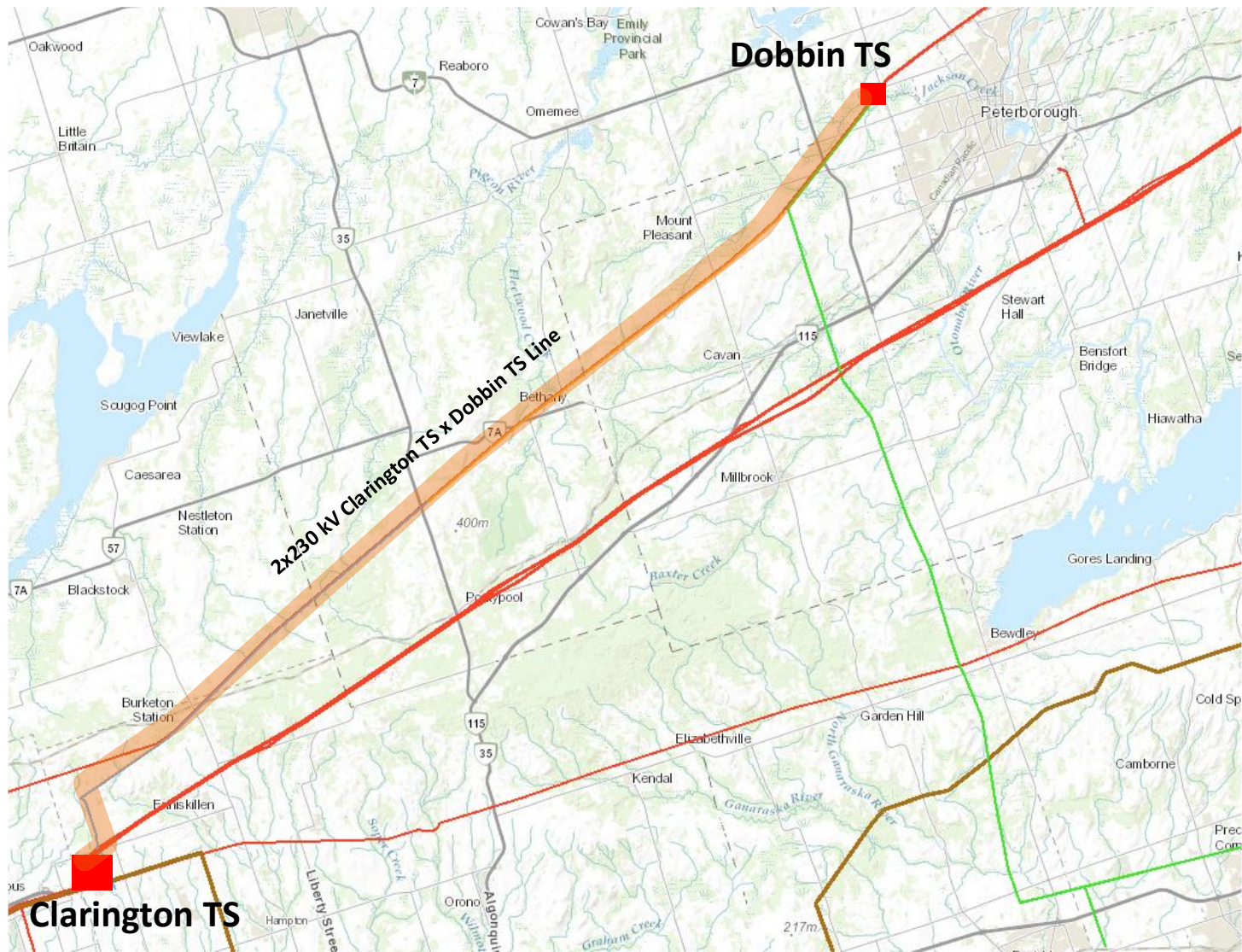


Figure 2: Geographical Overview of Durham Kawartha Power Line Project.

1.3 Connected Customers

The purpose of the CIA is to assess the impact of the proposed new transmission facilities on existing transmission customers connected to Hydro One's transmission system in the vicinity of Clarington TS and Dobbin TS. The customers within the study scope are listed in Table 1 below.

Table 1: Customer List under this CIA study

Station	Customer	Supply Circuit
Enfield TS	Hydro One Distribution	T32H, T29C, T28C, T23C, T31H, T26C, T22C, T33E, T25B, T24C
	Oshawa PUC Networks Inc.	
Dobbin TS	Hydro One Distribution	P15C, X1P, C27P
Mazinaw DS	Hydro One Distribution	X1P
Mountain Chute GS	Ontario Power Generation Inc.	X1P
Dobbin DS	Hydro One Distribution	P3S, P4S
Port Hope TS	Hydro One Distribution	P3S, P4S
TCPL Cobourg CTS	TransCanada Pipelines Limited	P4S
Enbridge PL HILT CTS	Enbridge Pipelines Inc.	P4S
Sidney TS	Hydro One Distribution	P3S, P4S
Seaton MTS	Ellexicon Energy Inc.	C10A, C28
Wilson TS	Hydro One Distribution	T29C, T23C
	Oshawa PUC Networks Inc.	
Thornton TS	Hydro One Distribution	T24C, T26C
	Oshawa PUC Networks Inc.	
Oshawa GM TS	General Motors of Canada Company	T24C, T26C
Whitby GS	Whitby Cogeneration Limited Partnership	T26C
Gerdau Whitby CTS	Gerdau Ameristeel	T24C, T26C
Atlantic Packaging CTS	Atlantic Packaging Products Ltd.	T24C, T26C
Whitby TS	Hydro One Distribution	T23C, T24C, T26C, T29C
	Ellexicon Energy Inc.	

2.0 CUSTOMER IMPACT ASSESSMENT

Load flows and short circuit analysis were conducted to assess the impact of the proposed project on Hydro One's existing transmission customers in the area. The voltages and short circuit currents were assessed as per Appendix 2 of Ontario Energy Board's Transmission System Code (TSC)

2.1 Load Flow Study

Load flow studies were carried out to analyze the impact of this project on Hydro One's transmission customers in the vicinity of the proposed project. The base case developed for the load flow studies was based on the 2025 Summer Peak base case with assumptions below.

- Load growth was projected up to 2039.
- All existing and committed facilities in 2029.

The contingencies below are major contingencies that would affect the customers in the area considered for both thermal loading and voltage performance assessment for each case above:

- A single contingency loss of 230 kV T40P, T41P, P15C, C27P X1P, C10A, C28, T23C, T24C, T26C and T29C
- Loss of Autotransformer T7 or T8
- A double contingency loss of T40P and T41P

The study focused on the voltage impact before and after for scenarios described above.

The CIA also assessed the area voltage after the incorporation of the project for the base case (with all facilities in service) and for either line out of service. All bus voltages are within Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria, and no voltage violations were found for these conditions and in turn suggests a strong backbone system with the incorporation of the Durham Kawartha Power Line project.

2.2 Thermal Loading

Load flow analysis indicates that the addition of the proposed T40P and T41P 230 kV circuits does not result in thermal overloads on transmission facilities within the study area for any single element contingency, including the loss of T40P, T41P, or the existing P15C circuit. Under these conditions, all monitored facilities remain within their applicable thermal ratings.

Outage and contingency scenarios that result in the simultaneous loss of both new circuits, T40P and T41P including shared tower contingencies or a sequential outage and contingency event effectively return the transmission system to currently existing project operating conditions. Under these scenarios, power flows are again fully dependent on the existing P15C 230 kV circuit, which results in loading that exceeds its Short-Term Emergency (STE) thermal rating.

To address this condition the implementation of a new Load Rejection (LR) Remedial Action Scheme (RAS) is required in conjunction with the installation of the new transmission circuits. The proposed RAS will be implemented as a revision to the existing Dobbin TS Load Rejection RAS. The current flow based P15C overload rejection logic will be replaced with a contingency based RAS design. The RAS will have the capability to reject adequate loads at Dobbin TS and Dobbin DS, following the shared tower contingency to T40P and T41P or an outage of one circuit followed by a contingency on the other, so that after the rejection, P15C is not overloaded. Please see Appendix A for further details.

2.3 Voltage Performance

Following each n-1 contingency, all the HV and LV buses in the area remain within voltage limits set in the Transmission System Code (TSC) with load growth projected up to 2039 as given in Appendix A. Specifically, following a contingency and before the ULTC action, all the HV and LV buses within the 10% voltage change allowed by the TSC. After the ULTC response, the HV buses were within the 10 % voltage change and all the LV buses were within the 5 % voltage change, allowed by the TSC. The connection of DKPL improves the voltage performance of station in direct vicinity when P15C is loss and have no adverse effect on other stations in the study area.

The SIA completed by IESO found that the project has no negative impact on the transmission system. The area voltage is kept within limits. Please refer to IESO document CAA ID 2024-823.

2.4 Short Circuit Study

The proposed project will be contributing short circuit currents during a fault. Short circuit studies were carried out to assess the impact of this project. The Appendix B of the Transmission System Code (TSC) specifies fault level limits, which are summarized below for reference:

<i>Nominal Voltage (kV)</i>	<i>Max. 3-Phase Fault (kA)</i>	<i>Max. SLG Fault (kA)</i>
500	80 ⁽¹⁾	80 ⁽¹⁾
230	63	80 ⁽¹⁾
115	50	50
44	20 ⁽²⁾	19 ⁽²⁾
27.6 (4-wire)	17	12

Notes: (1) – Usually limited to 63 kA

(2) – Effective September 1, 2010, Hydro One requires a 5% margin on the acceptable TSC limits and equipment ratings at voltage levels of <50kV to account for other sources of fault current on the distribution system such as unmodelled synchronous motors and data inaccuracies.

The results of short circuit studies showing short circuit levels at stations in the immediate vicinity of the proposed load are shown in Appendix B. The remainder of the stations in the region have less than 100A increase at the high voltage connection point. A review of short circuit study concludes that with the new line connection, the five existing 230 kV breakers are limited and will be replaced by new 63 kA breakers. The short circuit levels at all other stations remain within existing equipment ratings or short circuit limits apart from the Dobbin TS 44 kV bus which the SC increase is above 19kA for SLG fault limit as per TSC. To limit fault and ensure compliance with equipment ratings, the 44 kV bus tie breaker (BY) will be operated in the normally open position when both transformers T3 and T4 are in service. When either transformer T3 or T4 is out of service, the 44 kV bus tie breaker (BY) will be closed to allow the remaining transformer to supply the full station load and maintain continuity of service.

Customers are requested to review the results and determine if the new fault levels are within their equipment ratings and whether their station grounding systems are adequate.

2.5 Customer Reliability

The IESO SIA concluded that the proposed Clarington TS x Dobbin TS new double-circuit 230 kV transmission line will not have a material adverse impact on the reliability of the Integrated Power System, provided the recommended modifications to the Dobbin Remedial Action Scheme (RAS) are implemented.

The new transmission line will strengthen the bulk transmission system by increasing power transfer capability into Eastern Ontario, enabling the system to reliably supply forecast load growth in the region. As a result, overall transmission system reliability in Eastern Ontario will improve, leading to enhanced power supply reliability for customers in the region.

2.6 Conclusion

This CIA study presents results of incorporating the Durham Kawartha Power Line project which is planned to be completed in December 2029. The CIA has reviewed the impact of the project on the existing transmission customers in the area.

The assessment as reported in SIA CAA 2024-823 shows that voltage performance and circuit loading are within applicable criteria with the application of load and generation rejection as recommended in the report. As shown in Appendix A, after the incorporation of this project, the voltage performance of the transmission connection points near Dobbin TS will be improved.

Short-circuit studies were conducted to assess the anticipated fault levels at customer transmission connection points following the integration of the Clarington TS - Dobbin TS new double-circuit 230 kV transmission line. The studies indicate that there will be short circuit increases to Dobbin TS

230kV/115kV, and 44kV busses, to manage the increased short-circuit levels resulting from the project, the Dobbin TS 44 kV bus will be required to operate with the bus tie normally open. All other stations in the GTA East region, and Peterborough to Kingston region, do not have any significant short circuit increase and are within the limits specified in the Transmission System Code.

Area customers are advised to review the potential impacts of the changed short-circuit levels on their facilities and to take appropriate and timely actions to address any safety or technical issues that may arise as a result of the project, which is expected to be in service in 2029.

APPENDIX A: LOAD FLOW STUDIES

Table A1 shows loading of P15C before and after the incorporation of project. No other transmission lines or station flows in the region are significantly impacted by the project.

The area generation assumptions and area load forecast used in the study were taken from the System Impact Assessment (SIA) report for the Durham Kawartha Power Line Project (CAA ID 2024-823)

Table A1: Flow on P15C Before and After connection of Project.

2029- Before Connection of 2x230 kV Clarington TS x Dobbin TS Circuits					
Circuit Name	Nominal Voltage (kV)	Contingency	Line Loading (Amps)	STE Rating (Amps)	Line Loading (%)
P15C	230	-	589	572	103%
P15C	230	230 kV C27P	742	572	130%
P15C	230	230 kV X1P	571	572	100%
P15C	230	115 kV B1S	599	572	105%

2029- After Connection of 2x230 kV Clarington TS x Dobbin TS Circuits (T40P and T41P)					
Circuit Name	Nominal Voltage (kV)	Contingency	Line Loading (Amps)	STE Rating	Line Loading (%)
P15C	230	-	227	572	40%
P15C	230	230 kV C27P	242	572	42%
P15C	230	230 kV X1P	219	572	38%
P15C	230	115 kV B1S	230	572	40%
P15C	230	230 kV T40P	322	572	56%
P15C	230	230 kV T41P	322	572	56%
P15C	230	230 kV T40P+T41P	589	572	103%

Table A2 presents the voltage performance of buses where the pre-ULTC voltage change exceeded $\pm 2\%$.

Table A2: Voltage Performance Analysis

			Base Case with 2029 loading - Before DKPL Project					Base Case with 2029 loading - After DKPL Project				
Station Bus	Nominal Voltage (kV)	Contingency		Post Contingency Voltage					Post Contingency Voltage			
			Pre-Contingency Voltage (kV)	Pre-ULTC (kV)	ΔV	Post-ULTC (kV)	ΔV	Pre-Contingency Voltage (kV)	Pre-ULTC (kV)	ΔV	Post-ULTC (kV)	ΔV
SIDNEY TS BQ	44	P15C	46.1	42.9	-7%	45.0	-3%	46.2	46.1	0%	46.1	0%
ENBRG HILTON CTS	115		121.7	113.1	-7%	110.9	-9%	123.1	122.8	0%	122.8	0%
TCPL COBOURG CTS	115		122.0	113.5	-7%	111.2	-9%	123.4	123.1	0%	123.1	0%
PORT HOPE TS BY	44		46.9	43.7	-7%	45.5	-3%	47.4	47.2	0%	47.2	0%
SIDNEY TS	115		121.3	112.8	-7%	110.7	-9%	122.8	122.4	0%	122.4	0%
PORT HOPE TS JQ	44		46.1	43.0	-7%	45.0	-2%	46.1	46.0	0%	46.0	0%
PORT HOPE P4S	115		122.3	114.0	-7%	111.7	-9%	123.7	123.4	0%	123.4	0%
PORT HOPE P3S	115		122.4	114.2	-7%	111.9	-9%	123.7	123.4	0%	123.4	0%
DOBBIN TS	115		125.1	117.0	-6%	114.9	-8%	126.5	126.2	0%	126.2	0%
DOBBIN DS	115		125.1	117.0	-6%	114.9	-8%	126.5	126.1	0%	126.1	0%
DOBBIN DS B1	27.6		29.0	27.1	-6%	28.3	-2%	29.1	29.0	0%	29.0	0%
DOBBIN DS B3	27.6		29.0	27.1	-6%	29.1	-1%	29.1	29.0	0%	29.0	0%
DOBBIN TS	230		238.1	223.3	-6%	219.5	-8%	241.7	241.0	0%	241.0	0%
DOBBIN TS BY	44		46.4	43.5	-6%	45.3	-2%	46.6	46.5	0%	46.5	0%
MAZINAW DS B	12.5		13.3	12.9	-3%	13.2	-1%	13.3	13.2	0%	13.2	0%
MAZINAW DS	230		244.6	236.8	-3%	234.8	-4%	246.5	246.1	0%	246.1	0%
MAZINAW DSR1	12.5		12.1	11.7	-3%	11.6	-4%	12.2	12.2	0%	12.2	0%

			Base Case with 2029 loading - Before DKPL Project					Base Case with 2029 loading - After DKPL Project				
Station Bus	Nominal Voltage (kV)	Contingency		Post Contingency Voltage					Post Contingency Voltage			
			Pre-Contingency Voltage (kV)	Pre-ULTC (kV)	ΔV	Post-ULTC (kV)	ΔV	Pre-Contingency Voltage (kV)	Pre-ULTC (kV)	ΔV	Post-ULTC (kV)	ΔV
PORT HOPE P4S	115	P3S	122.3	118.1	-3%	118.0	-4%	123.7	119.4	-4%	119.3	-4%
PORT HOPE TS BY	44		46.9	45.3	-3%	45.3	-3%	47.4	45.8	-3%	45.8	-3%
PORT HOPE TS JQ	44		46.1	44.6	-3%	45.1	-2%	46.1	44.7	-3%	45.1	-2%
TCPL COBOURG CTS	115		122.0	118.3	-3%	118.2	-3%	123.4	119.6	-3%	119.6	-3%
PORT HOPE P3S	115	P4S	122.4	118.3	-3%	118.5	-3%	123.7	119.3	-4%	119.5	-3%
PORT HOPE TS BY	44		46.9	45.4	-3%	45.5	-3%	47.4	45.8	-3%	45.8	-3%
PORT HOPE TS JQ	44		46.1	44.7	-3%	45.3	-2%	46.1	44.6	-3%	44.9	-3%
WHITBY TS JQ	44	T23C	45.7	42.5	-7%	45.7	0%	45.7	42.6	-7%	45.7	0%
WILSON TS JQ	44		45.7	42.8	-6%	45.4	-1%	45.7	42.9	-6%	45.4	-1%
WILSON TS EZ	44		43.9	41.9	-4%	43.7	0%	43.9	41.9	-4%	43.7	0%
OSHAWA GM TS CD	13.8	T24C	14.3	13.6	-5%	14.3	0%	14.3	13.6	-5%	14.3	0%
WHITBY TS EZ	44		44.0	42.4	-4%	44.3	1%	44.1	42.4	-4%	44.3	1%
OSHAWA GM TS AB	13.8		14.3	13.8	-4%	14.3	0%	14.3	13.8	-4%	14.3	0%
WHITBY TS BY	27.6		28.9	28.0	-3%	29.0	0%	28.9	28.1	-3%	29.0	0%
OSHAWA GM TS CD	13.8	T26C	14.3	13.5	-6%	14.3	0%	14.3	13.5	-6%	14.2	-1%
OSHAWA GM TS AB	13.8		14.3	13.7	-4%	14.2	0%	14.3	13.7	-4%	14.2	0%
WHITBY TS EZ	44		44.0	42.2	-4%	44.6	1%	44.1	42.3	-4%	44.2	0%
THORNTON TS BY	44		46.5	45.0	-3%	45.5	-2%	46.6	45.0	-3%	45.5	-2%
WHITBY TS BY	27.6		28.9	28.0	-3%	28.9	0%	28.9	28.0	-3%	28.9	0%
WHITBY TS JQ	44	T29C	45.7	42.8	-6%	45.4	-1%	45.7	42.8	-6%	45.5	-1%
WILSON TS JQ	44		45.7	42.9	-6%	45.4	-1%	45.7	42.9	-6%	45.4	-1%
WILSON TS EZ	44		43.9	41.9	-5%	43.7	0%	43.9	41.9	-4%	43.7	0%

APPENDIX B: SHORT CIRCUIT STUDY

Station Bus	Nominal Voltage (kV)	Fault Levels (kA)				Fault Levels (kA)				Breaker Ratings (kA)	
		Before Project				After Project					
		Sym.		Asym.		Sym.		Asym.		Sym.	Asym.
		3Ph	LG	3Ph	LG	3Ph	LG	3Ph	LG	3Ph/LG	3Ph/LG
Clarington TS	500	36.7	33.4	50.1	43.7	36.8	33.5	50.3	43.9	63.0	75.6
Clarington TS	230	50.2	51.6	69.4	72.4	49.2	50.9	68.2	71.6	63.0	81.0
Dobbin TS	230	6.7	7.4	7.0	8.0	14.7	14.1	15.9	16.0	63(21) ²	63.0(21) ²
Dobbin TS	115	8.8	10.8	8.8	11.3	15.1	17.5	15.6	19.4	22.7	25.0
Dobbin TS BY ¹	44	11.9	16.5	12.8	17.9	14.6	19.9	17.4	23.8	17.0	18.7
Dobbin TS B ¹	44	NA	NA	NA	NA	8.8	11.8	10.9	14.7	17.0	18.7
Dobbin TS Y ¹	44	NA	NA	NA	NA	7.3	10.0	9.2	12.6	17.0	18.7
Dobin DS B1	27.6	3.0	3.2	3.4	3.6	3.2	3.3	3.6	3.8	-	-
Dobbin DS B3	27.6	3.0	3.2	3.3	3.6	3.1	3.3	3.5	3.7	-	-
Enfield TS BY	44	15.8	7.0	22.8	9.7	15.8	7.0	22.8	9.7	31.5	37.8
Seaton C10A	230	31.9	27.0	36.7	29.3	31.9	26.9	36.7	29.2	-	-
Seaton C28	230	34.3	29.9	39.1	32.4	29.3	25.7	33.8	28.0	-	-
Atlantic Packaging CTS T24C	230	15.0	11.8	16.3	12.6	14.9	11.8	16.3	12.6	-	-
Atlantic Packaging CTS T26C	230	15.5	12.7	17.0	14.1	15.4	12.6	16.9	14.1	-	-
Gerdau Whitby CTS T24C	230	14.4	11.2	15.6	12.0	14.4	11.2	15.6	12.0	-	-
Gerdau Whitby CTS T26C	230	14.8	12.1	16.3	13.3	14.8	12.0	16.2	13.3	-	-
Oshawa GM TS T24C	230	13.4	10.4	14.6	11.2	13.4	10.4	14.6	11.2	-	-
Oshawa GM TS T26C	230	13.8	11.0	15.0	11.9	13.7	10.9	15.0	11.9	-	-
Oshawa GM TS AB	13.8	14.4	1.1	19.2	1.4	14.4	1.1	19.2	1.4	31.5	34.7
Oshawa GM TS CD	13.8	14.4	1.1	19.3	1.4	14.4	1.1	19.3	1.4	31.5	34.7

Station Bus	Nominal Voltage (kV)	Fault Levels (kA)				Fault Levels (kA)				Breaker Ratings (kA)	
		Before Project				After Project					
		Sym.		Asym.		Sym.		Asym.		Sym.	Asym.
		3Ph	LG	3Ph	LG	3Ph	LG	3Ph	LG	3Ph/LG	3Ph/LG
Mountain Chute GS	230	3.9	4.4	4.7	5.5	4.2	4.6	5.0	5.7	-	-
TCPL Cobourg CTS	115	4.0	2.9	4.0	2.9	4.4	3.0	4.4	3.0	-	-
Enbridge Hilton CTS	115	4.0	3.1	4.0	3.1	4.2	3.2	4.2	3.2	-	-
Whitby CGS	230	15.1	12.3	16.6	13.8	15.1	12.3	16.5	13.8	-	-
Wilson TS JQ	44	15.8	7.1	20.5	9.5	15.8	7.1	20.5	9.5	18.8	20.7
Wilson TS EZ	44	15.0	6.9	20.4	9.5	15.0	6.9	20.4	9.5	40.0	48.0
Thornton TS BY	44	13.9	6.8	18.5	9.2	13.9	6.8	18.5	9.2	18.8	20.7
Whitby TS JQ	44	16.7	12.0	23.3	16.7	16.7	11.9	23.3	16.7	31.5	37.8
Whitby TS BY	27.6	11.4	5.5	14.8	7.3	11.4	5.5	14.8	7.3	40.0	48.0
Whitby TS EZ	44	15.8	7.0	21.8	9.6	15.8	7.0	21.8	9.6	40.0	48.0
Mazinaw DS	12.5	3.2	3.3	3.5	3.5	3.2	3.3	3.5	3.5	-	-
Port Hope TS JQ	44	7.9	5.5	8.0	6.0	8.6	5.7	8.8	6.3	18.8	20.7
Port Hope TS BY	44	8.1	5.3	8.2	5.9	8.8	5.5	9.0	6.2	12.6	13.8
Sidney TS BQ	44	9.1	8.4	9.1	8.6	9.4	8.5	9.4	8.8	18.8	20.7

Note:

1. Due to increased short-circuit levels at the Dobbin TS 44 kV bus, the 44 kV bus-tie breaker (BY) will be operated in the normally open position when both transformers T3 and T4 are in service, in order to limit fault duty on station equipment, Dobbin TS BY bus will become B and Y bus respectively. When either transformer T3 or T4 is out of service, the 44 kV bus-tie breaker (BY) will be closed to allow the remaining transformer to supply all station load and maintain continuity of service.
2. The replacement breaker is rated 63 kA; however, due to other station limitations, the short-circuit limit at the Dobbin 230 kV bus is 21 kA.

REGIONAL AND BULK PLANNING

As set out in the Application, the proposed Project is driven by bulk planning needs. However, the preceding regional planning cycle also identified supply capacity requirements and thermal capacity constraints in the Peterborough to Quinte West region. These regional needs were considered in coordination with the bulk system planning to ensure the broader system was considered in the development of the IESO's recommendations for Eastern Ontario. The most recent bulk and regional planning reports are provided as **Attachments 1 through 3** of this Schedule, as noted below:

Attachment 1: IESO Bulk Report: *Gatineau Corridor End-of-Life Study* (December 2022)

Attachment 2: Peterborough to Kingston RIP (May 27, 2022)

Attachment 3: Peterborough to Kingston IRRP (November 4, 2021)

The IESO's bulk system report concludes that the construction of the Project is the most effective way to address the long-term supply capacity needs and ensure reliable electricity supply to the Peterborough to Quinte West and Ottawa regions. This conclusion is further supported by the IESO's supplemental evidence provided as **Attachment 6 to Exhibit B, Tab 3, Schedule 1**. The IESO continues to assess bulk and regional system requirements for Eastern Ontario predicated on the completion of the Project.

**IESO BULK REPORT:
GATINEAU CORRIDOR END-OF-LIFE STUDY
(DECEMBER 2022)**



Gatineau Corridor End-of-Life Study

December 2022



Disclaimer

This document and the information contained herein is provided for informational purposes only. The IESO has prepared this document based on information currently available to the IESO and reasonable assumptions associated therewith, including relating to electricity supply and demand. The information, statements and conclusions contained in this report are subject to risks, uncertainties and other factors that could cause actual results or circumstances to differ materially from the information, statements and assumptions contained herein. The IESO provides no guarantee, representation, or warranty, express or implied, with respect to any statement or information contained herein and disclaims any liability in connection therewith. Readers are cautioned not to place undue reliance on forward-looking information contained in this report as actual results could differ materially from the plans, expectations, estimates, intentions and statements expressed in this report. The IESO undertakes no obligation to revise or update any information contained in this report as a result of new information, future events or otherwise. In the event there is any conflict or inconsistency between this document and the IESO market rules, any IESO contract, any legislation or regulation, or any request for proposals or other procurement document, the terms in the market rules, or the subject contract, legislation, regulation, or procurement document, as applicable, govern.

Table of Contents

1. Executive Summary	5
2. Introduction	6
2.1 Power System Planning in Ontario	6
2.2 Gatineau Corridor End-of-Life Study	6
2.3 Gatineau Corridor and Key Areas of Interest	6
3. Planning for Transmission Asset End-of-Life in the Gatineau Corridor	9
3.1 Transmission Asset End-of-Life	9
3.2 Gatineau Corridor Transmission Asset End-of-Life	9
3.3 Potential Opportunities for Right-sizing or Decommissioning	10
4. Demand Forecasts	12
4.1 Peterborough to Quinte West Area Demand	12
4.2 Ottawa Area Demand	12
5. Supply Capability to Focus Areas	14
5.1 Peterborough to Quinte West Supply	14
5.1.1 Peterborough to Quinte West Internal Resources	14
5.1.2 Peterborough to Quinte West Load Meeting Capability	14
5.2 Ottawa Supply	15
5.2.1 Ottawa Internal Resources	15
5.2.2 Ottawa Load Meeting Capability	15
6. Need for Additional Supply	17
6.1 Capacity Requirement	17
6.1.1 Flow into Dobbin and Sidney	17
6.1.2 Flow into Ottawa	18
7. Analysis of Alternatives	20
7.1 Alternatives Considered	22
7.2 Energy Efficiency	26

7.2.1	Energy Efficiency Potential in Ottawa	27
7.3	Comparison of Alternatives	29
7.3.1	Technical Comparison	29
7.3.2	Cost Comparison	30
8.	Linkages with Regional Planning	31
8.1	Peterborough to Kingston Region	32
8.2	Greater Ottawa Region	32
8.3	Greater Toronto Area East	33
9.	Engagement	34
9.1	Engagement Principles	34
9.2	Engagement Approach	35
9.3	Bringing Communities to the Table	36
9.4	Engaging with Indigenous Communities	36
10.	Conclusions and Recommendations	37
	Appendix A – Planning Assessment Criteria	38
	Appendix B – Load Forecast and Supply Need Data	40
	Appendix C – Assessment of Supply	43
	Appendix D – Economic Assessment Assumptions	44
	Appendix E – Sizing Battery Energy Storage Systems	46

List of Abbreviations

Abbreviation	Description
APO	Annual Planning Outlook
APS	Achievable Potential Study
BESS	Battery Energy Storage System
CCGT	Combined Cycle Gas Turbine
CDM	Conservation and Demand Management
DER	Distributed Energy Resources
ENS	Energy Not Served
EOL	End of Life
FIDS	Flow into Dobbin and Sidney interface
FIO	Flow into Ottawa interface
HONI	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
MTS	Municipal Transformer Station
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NWA	Non-wires Alternative
OEB	Ontario Energy Board
ORTAC	Ontario Resource Transmission Assessment Criteria
RAS	Remedial Action Scheme
SCGT	Simple Cycle Gas Turbine
TS	Transformer Station

1. Executive Summary

The Gatineau Corridor End-of-Life Study examines transmission equipment reaching end-of-life (EOL) in the Gatineau transmission corridor along with forecast reliability concerns in the areas supplied by those transmission circuits, Ottawa and Peterborough to Quinte West. Consideration of replacement options for significant EOL transmission facilities through an IESO-led integrated planning process can ensure assets are renewed in a cost-effective manner that aligns with the evolution of the electricity system (e.g. decarbonisation of the electricity sector and the economy) and reflects potential new or emerging needs that have arisen in an area since the assets were first installed. The reliability issues identified through the study include:

- Approximately 800 km of the 230 kV circuits on the Gatineau Corridor (Oshawa to Ottawa) are expected to reach end-of-life over the next 5 to 10 years
- The Load Meeting Capability (LMC) for the Ottawa area is forecast to be exceeded in the mid 2020's
- The LMC for the Peterborough to Quinte West area is insufficient today

To minimize cost, minimize land-use impacts, mitigate forecast risk, preserve options to increase system capability in the future and due to lack of cost effective stand-alone resource or energy efficiency alternatives, the following integrated solution package is recommended to address the transmission equipment EOL needs and accommodate the demand forecast for the Ottawa and the Peterborough to Quinte West areas over the long-term:

- Refurbish all 800 km of 230 kV circuits on the Gatineau Corridor identified as nearing EOL
- Build a new double circuit 230 kV transmission line into Dobbin TS (in Peterborough) from either Cherrywood TS (in Pickering) or Clarington TS (in Oshawa) with a planned in-service of 2029
- Pursue up to 230 MW of additional system cost-effective energy efficiency in the Ottawa area over the 20 year planning horizon, while monitoring demand growth and resource acquisition activities in the Ottawa zone
- Update and expand the use of remedial action schemes (RAS) in the Peterborough and Ottawa areas to meet planning standards and further improve both areas' LMCs

This solution package represents the lowest cost option, with transmission reinforcements estimated to cost approximately \$650 M. The transmission reinforcements ensure reliability in the Peterborough to Quinte West area is sufficient for the next 20 years and reliability in the Ottawa area is sufficient until 2037. If the 230 MW of additional energy efficiency is implemented, Ottawa area's reliability would also be sufficient over the 20 year planning horizon. The solution package maintains the capacity of the existing circuits being refurbished and avoids the need to address localized issues that would result from retiring the circuits (i.e. reconfiguration of stations and short line builds in the Ottawa area).

2. Introduction

2.1 Power System Planning in Ontario

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

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

2.2 Gatineau Corridor End-of-Life Study

The Gatineau Corridor End-of-Life Study examines transmission equipment reaching end-of-life (EOL) in the Gatineau transmission corridor along with forecast reliability concerns in the areas of Ottawa and Peterborough to Quinte West which are supplied by the circuits located within the corridor. Consideration of replacement options for EOL transmission facilities through an integrated planning process can ensure assets are renewed in a cost-effective manner that aligns with the evolution of the electricity system (e.g. decarbonisation of the electricity sector and the economy) and new or emerging issues that have arisen in an area since the assets were originally constructed.

2.3 Gatineau Corridor and Key Areas of Interest

Gatineau Corridor

The Gatineau corridor is a 300 km long transmission corridor that runs from Durham region to Peterborough and onto Ottawa. The Gatineau corridor was originally constructed in the late 1920's to early 1930's primarily to transfer power from hydro electric facilities in eastern Ontario and Quebec to the Toronto load centre. The Gatineau corridor consists of five (5) 230 kV transmission lines (P15C/C27P, T22C, T32H/C25H, T33E/E34M, and T31H/H27H), and have a combined length of 1,300 line-kms. Today, the corridor serves a number of purposes which include facilitating generation, transferring bulk system flows across eastern Ontario, and supplying loads in the Peterborough to Quinte West and Ottawa areas.

Peterborough to Quinte West Area

The Peterborough to Quinte West area is located in eastern Ontario and includes Peterborough County, Northumberland County, Prince Edward County, and the City of Quinte West. The electricity demand of this area is a mix of residential, commercial and industrial loads, encompassing diverse economic activities ranging from educational institutions, large business parks, health care, national defence bases, manufacturing and industrial processes.

This area is supplied by a number of 230 and 115 kV transmission lines coming from the directions of Durham region and the County of Lennox and Addington. The area is served by four supply stations which include Otonabee TS, Dobbin TS, Port Hope TS, and Sidney TS. While Otonabee TS is in close proximity to Dobbin TS which is the other supply station in Peterborough, the upstream electricity system serving Otonabee TS is distinct from the system serving the other three stations. When describing system capability and demand forecasts in this report, the definition of the Peterborough to Quinte West area excludes Otonabee TS.

Electricity demand in this summer peaking Peterborough to Quinte West area has been fairly constant and has historically reached approximately 310 MW. There is approximately 300 MW of transmission connected hydro-electric generation located in the Greater Madawaska and Renfrew areas supporting the load in Peterborough to Quinte West.

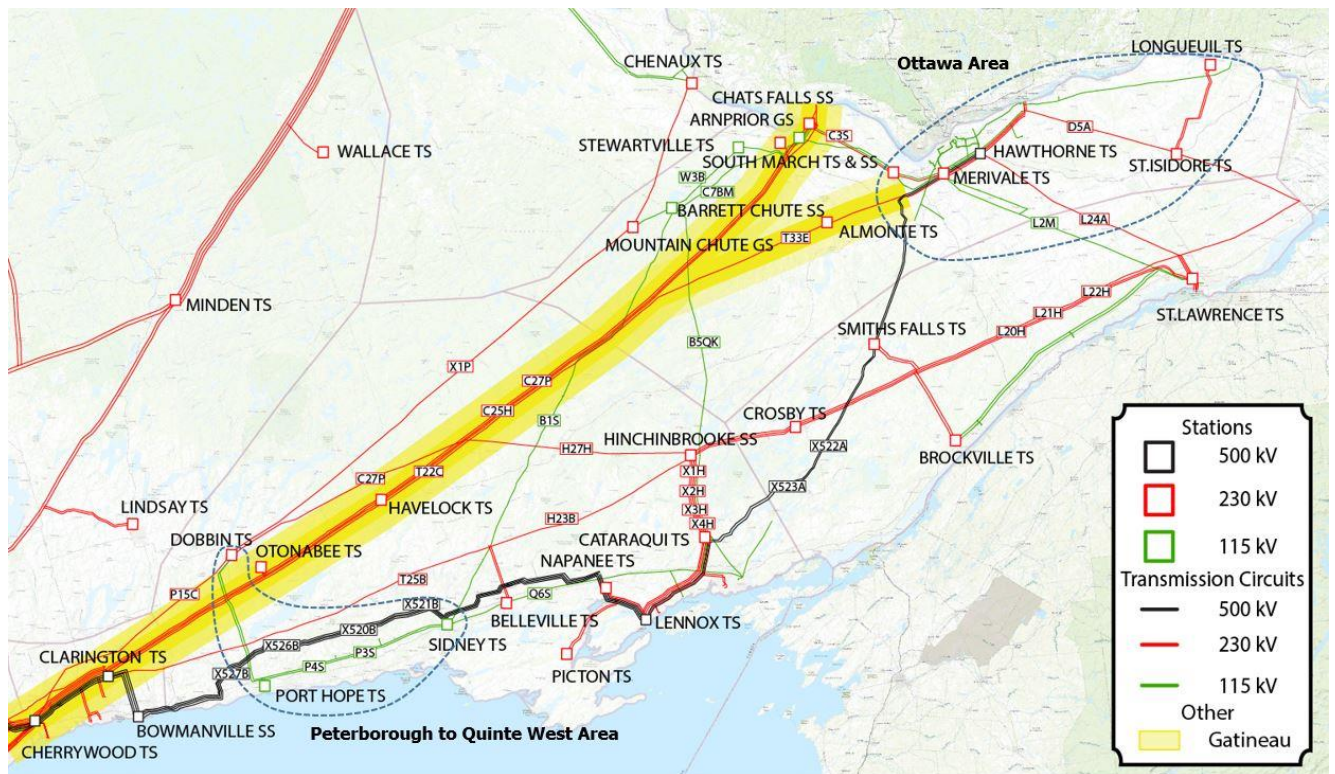
Ottawa Area

The City of Ottawa is the second largest city in Ontario with a population of approximately 1 million people. The city has seen its population grow steadily by approximately 1.5% annually since 2015, and with that has also seen a steady growth of its developed lands. This development is primarily focused in five areas: the downtown core, Nepean & Riverside South, South Kanata & Stittsville, the Village of Richmond, and Orleans. This growth is primarily being seen through the development of new mixed commercial/residential communities, intensification of existing communities, and major projects like the Ottawa Light Rail Transit system. In rural Ottawa, the economy contributes over \$1 billion to the GDP. Rural economic activity includes such things as agriculture, retail sales, construction, forestry and mining (aggregates), tourism, manufacturing, personal and business services, and transportation.

Ottawa is supplied by a number of 500, 230 and 115 kV transmission lines coming from the directions of Peterborough County and the County of Lennox and Addington. Electricity demand in this summer peaking area has been steadily growing and has historically reached approximately 1,800 MW. There are a number of different electricity supply resources in the surrounding area that help support the Ottawa load, including approximately 600 MW of hydro-electric generation located on the Madawaska and Ottawa rivers, 70 MW of gas generation located in the city, and three interties with Quebec system.

A map of the area highlighting the Gatineau corridor and the areas of Peterborough to Quinte West and Ottawa are shown in Figure 1.

Figure 1 | Map of Gatineau Corridor, Highlighting Areas of Interest



3. Planning for Transmission Asset End-of-Life in the Gatineau Corridor

3.1 Transmission Asset End-of-Life

Consideration of end-of-life (EOL) transmission asset replacement needs is an integral part of transmission planning. When an asset reaches EOL, a decision must be made to either replace it ("like-for-like" or "right-size") or, in some cases, decommission it to meet safety, reliability, environmental, and customer requirements. While the length of time varies, many transmission assets remain in use and deliver value for 40 years or more. Over such a long period of time, the functional requirements of the transmission system could change, as customer needs, system conditions, sector trends, and government policy evolve. Coordination of transmission asset replacement needs with other forecast reliability and security needs over the long-term is critical to maximizing the benefits and value of transmission system investments.

End-of-Life

EOL represents the state of having a high likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences. EOL is determined by the asset owner's risk-based assessments, taking into account such factors as reliability, loss of load, environmental considerations, and safety.

EOL is different from the "useful life" of asset which is an accounting estimate of the number of years it is likely to remain in service considering factors such as manufacturer guidelines, and historical asset performance, failure and retirement data.

As assets age and begin to approach their "useful life", assessments are carried out to determine their overall condition by examining asset-specific health metrics, along with performance history. Based on the results, equipment is scheduled to be replaced when it reaches EOL.

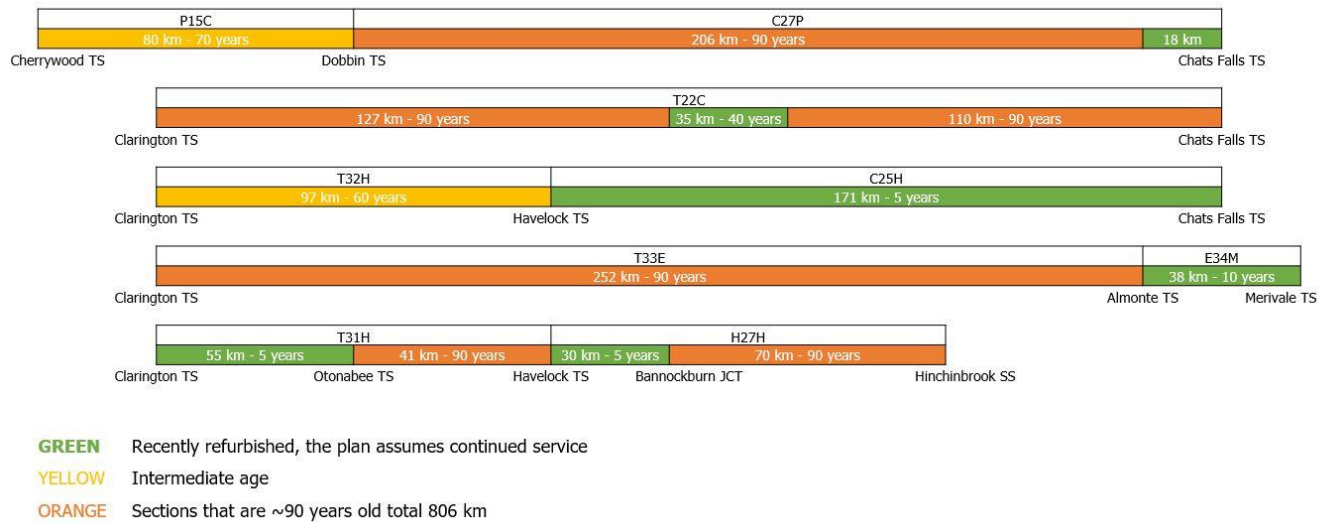
3.2 Gatineau Corridor Transmission Asset End-of-Life

The Gatineau Corridor was originally constructed in the late 1920's to early 1930's. At over 90 years since its original construction, large portions of corridor and specifically the transmission line conductors are nearing EOL, and in some instances have already been partially refurbished to maintain safety and reliability of the transmission system.

Transmission line conductors have a "useful life" of approximately 90 years. The facility owner, Hydro One Networks Inc. (HONI) has identified that the conductors on transmission lines C27P, T22C and T33E are nearing EOL based on asset condition assessments and require replacement before 2028. A decision to either refurbish the EOL facilities "like-for-like" or decommission and replace them with new cost effective facilities that provide additional value must be made now, as new transmission lines typically take 7 years to design, approve and construct.

While HONI has only identified the three transmission lines (C27P, T22C and T33E) as nearing EOL, other transmission lines in the corridor were examined in this study to identify potential candidates for right-sizing or decommissioning. Asset demographic age information for the Gatineau corridor transmission lines are illustrated in Figure 2.

Figure 2 | Age of Gatineau Corridor Transmission Line Conductors



3.3 Potential Opportunities for Right-sizing or Decommissioning

As noted earlier, while HONI has only identified the three transmission lines, C27P, T22C and T33E as nearing EOL, all transmission lines in the corridor were screened to identify potential candidates for right-sizing or decommissioning. The screening considered various qualitative factors such as the criticality of the facility on reliability, stranding recently refurbished facilities, and potential for other cost effective alternatives. The screening identified transmission lines T22C and T33E as potential candidates for decommissioning, as alternatives exist that are potentially more cost effective and/or provides greater system value. The transmission lines C27P, T32H, T31H, and H27H are recommended to be refurbished when they reach EOL as cost effective alternatives are not evident. The last remaining circuit in the corridor P15C, is essential to supplying Peterborough to Quinte West and also the eastern Ontario system. For this reason, the circuit P15C can either be refurbished or upgraded to help accommodate the forecast demand for Peterborough to Quinte West and Ottawa areas. A summary of the considerations for each transmission line is provided in

Table 1.

Table 1 | Opportunities for Right-sizing or Decommissioning in the Gatineau Corridor

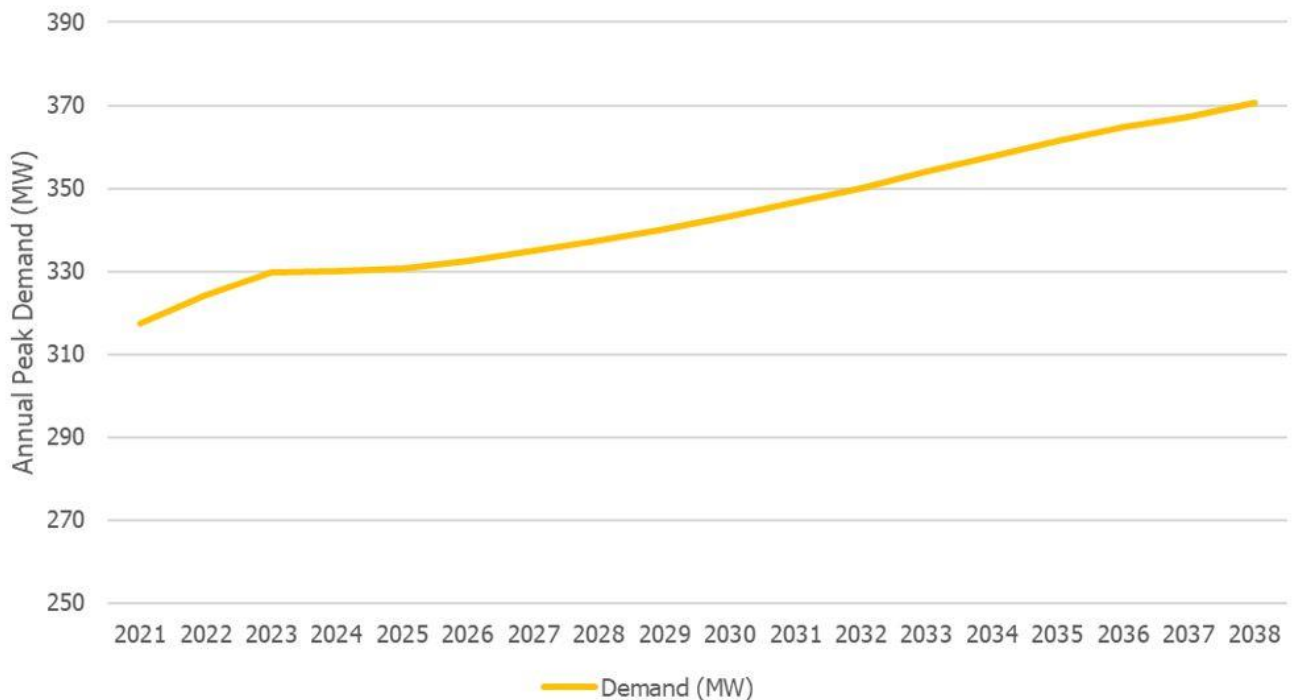
Transmission Line	Considerations	Opportunity for Right-sizing or Decommissioning
P15C/C27P	- The transmission lines P15C and C27P are critical supply circuits for the Peterborough to Quinte West area, P15C is a limiting constraint for the area's load meeting capability, as well as an upstream constraint for Ottawa's load meeting capability - The transmission line P15C runs between Pickering and Peterborough, passing by northern part of Durham region where load growth is expected most in the future - The transmission line C27P provides transmission connection for the 85 MW hydro-electric Arnprior Generating Station; if C27P were to be decommissioned, a portion of C27P would still need to be maintained (~15 km) - The vast majority of the C27P transmission line is approaching its "useful life" or has been identified as nearing EOL	P15C: Opportunity for upgrading C27P: No
T22C	- The transmission line T22C is critical in supporting the Ottawa area during certain transmission outage conditions - The transmission line T22C provides transmission connection for Otonabee TS; if T22C were to be decommissioned, supply to Otonabee TS would need to be reconfigured to one of the remaining circuits in the corridor - The majority of the transmission line has been identified as nearing EOL	T22C: Opportunity for decommissioning and replacing with a new transmission line that can offer additional system value
T32H/C25H	- The transmission line T32H/C25H is critical in supporting the Ottawa area during certain transmission outage conditions - The transmission lines T32H/C25H are critical supply circuits for Havelock - A portion of the transmission line (60%) was recently refurbished, and the remaining portion of the transmission line still has 30 years before reaching its average "useful life".	T32H/C25H: No
T33E/E34M	- The transmission line T33E/E34M is critical in supporting the Ottawa area during certain transmission outage conditions - The transmission lines T33E/E34M supply Almonte TS, Terry Fox TS, and Cambrian MTS; if T33E were to be decommissioned, a portion of T33E would still need to be maintained (~55km) and reconnected to one of the remaining circuits in the corridor - The entire T33E has been identified as nearing EOL	T33E: Opportunity for decommissioning and replacing with a new transmission line that can offer additional system value E34M: No
T31H/H27H	- The transmission line T31H/H27H helps support the loads in the areas of Lennox and Addington county, City of Kingston and Hinchinbrooke Township during certain transmission outage conditions - The transmission lines T31H/H27H are critical supply circuits for Havelock - A portion of the transmission line (40%) was recently refurbished, and the remaining portion of the transmission line has been identified as nearing EOL	T31H: No H27H: No

4. Demand Forecasts

4.1 Peterborough to Quinte West Area Demand

The Peterborough to Quinte West electricity demand is a mix of residential, commercial and industrial loads, encompassing diverse economic activities including educational institutions, large business parks, manufacturing and Canadian Forces bases. As shown in Figure 3, loads in this summer-peaking area are forecast to grow from 310 MW to 370 MW over the next 20 years.

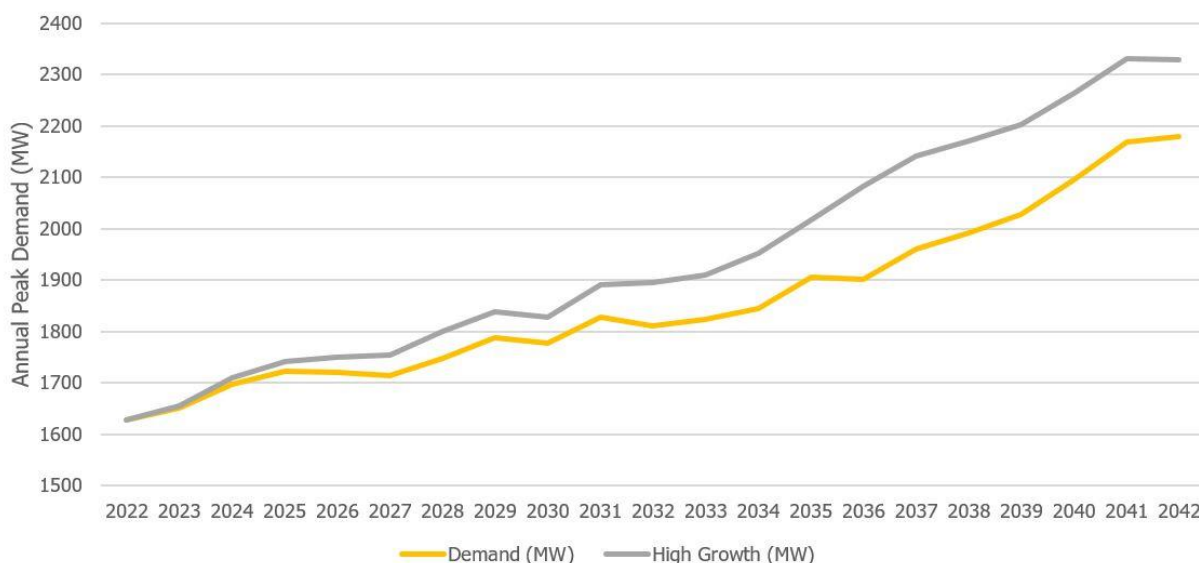
Figure 3 | Peterborough to Quinte West Demand Forecast



4.2 Ottawa Area Demand

The Ottawa electricity load growth is primarily being seen through the development of new mixed commercial/residential communities, intensification of existing communities, and major projects like the Ottawa Light Rail Transit system. As shown in Figure 4, loads in this summer-peaking area are forecast to grow from approximately 1650 MW to 2200 MW and 2350 MW over the next 20 years under the reference forecast and high growth scenario respectively.

Figure 4 | Ottawa Demand Forecast



Energy Evolution - Ottawa's Community Energy Transition Strategy

Energy Evolution¹ is the action plan for how Ottawa will meet its targets to reduce greenhouse gas emissions to zero by 2040 within the corporation, and by 2050 Ottawa-wide. Its vision is to transform Ottawa into a thriving city powered by clean, renewable energy. To achieve Ottawa's emission reduction targets will require:

- Significantly reduce energy demand for existing end-uses
- Phase out fossil fuels
- Increase use of renewable resources

Some of the identified actions to help achieve these targets will have an interdependency with planning the electricity system supplying the City of Ottawa, such as electrification of personal and commercial vehicles, electrification of heating, and new renewable resources.

The Energy Evolution strategy was approved by Ottawa's City Council on October 28, 2020. The impact of Energy Evolution on the peak electricity demand has yet to be quantified and is not included in the demand forecast shown in Figure 4. The IESO will work with the City of Ottawa and the Greater Ottawa regional planning working group during the next cycle of regional planning for Greater Ottawa (expected to commence in Q4 2022), to determine the how the strategy would impact the development of planning forecasts and scenarios, and what additional planning activities are necessary to support the City of Ottawa's Energy Evolution strategy. It's anticipated that to achieve energy evolution targets, Ottawa demand would grow beyond the high growth scenario and this uncertainty was considered when evaluating options.

¹ More information regarding Energy Evolution is available on the City of Ottawa's website ([link](#))

5. Supply Capability to Focus Areas

Supply capability to the areas of Peterborough to Quinte West and Ottawa is provided by a number of internal generation resources, as well as external resources accessed through the 500 kV and 230 kV transmission system (connecting the area to the rest of the Ontario)².

Planning of the transmission system focuses on ensuring that the system will operate reliably over a broad spectrum of system conditions and following a wide range of probable system contingencies. These planning events and performance requirements are established through a number of planning criteria and standards by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the IESO. The planning events examined are aimed to stress the transmission system (i.e. adjusting hydro-electric generation output for drought conditions, adjusting the load forecast for extreme weather, loss of one or more transmission and/or generation elements, etc.), and the performance requirements are intended to set a baseline for designing the electricity system.

As Ontario's electricity grid is made up of a variety of different energy resource types, it's important to note that the capability of each resource type at the time of peak loading conditions will vary. Variable generators such as wind and solar are modelled to historical output coincident with the time of peak. Hydro-electric generators are modelled to their historical output available during drought conditions.

5.1 Peterborough to Quinte West Supply

5.1.1 Peterborough to Quinte West Internal Resources

Transmission-connected resources currently comprise of mostly hydro-electric generation along the Madawaska and Ottawa rivers. These resources represent a combined total of 300 MW of installed generation capacity³, however the generation output is expected to be closer to 40 MW during drought conditions.

5.1.2 Peterborough to Quinte West Load Meeting Capability

Supply to Peterborough to Quinte West is also provided through the Flow into Dobbin and Sidney (FIDS) transmission interface which is bounded by two 115 kV circuits from Cataraqui TS (Q6S) and from Barrett Chute TS (B1S), and two 230 kV circuits in the Gatineau Corridor (P15C and C27P), providing supply from broader provincial resources.

² The mixture of resources used to supply the region's and the province's energy needs at any time is determined by the real-time energy market.

³ The region also has a significant number of distribution connected resources, mainly solar. The impact of these distributed resources has been considered as part of the reference load forecast.

The FIDS interface is thermally limited by 230 kV circuit P15C from Cherrywood TS to Dobbin TS in the summer. Generally, losing one or more of the interface circuits will lead to overloads of the remaining circuit(s). In the existing system, the load meeting capability of Peterborough to Quinte west area is limited to 270 MW today, the limiting phenomena is illustrated in Table 2.

Table 2 | Peterborough to Quinte West Load Meeting Capability

Transmission Equipment Out of Service	Phenomena	Peterborough to Quinte West LMC
Q6S	Thermal overload on P15C	270 MW
P15C	Thermal overload on Q6S	280 MW

5.2 Ottawa Supply

5.2.1 Ottawa Internal Resources

Transmission-connected resources currently comprise of a significant amount of hydro-electric generation along the Madawaska and Ottawa rivers, one natural-gas generation plant in the City of Ottawa, and one wind generator to the east of the city. These resources represent a combined total of 800 MW of installed generation capacity⁴. Over the next 20 years, contracts for the natural gas-fired and wind generators are expected to expire, which needs to be considered when identifying local supply needs.

5.2.2 Ottawa Load Meeting Capability

Supply to Ottawa is also provided through the Flow into Ottawa (FIO) transmission interface, defined as two 500 kV circuits from Lennox TS (X522A, X523A), and four 230 kV transmission circuits from Beauharnois (B5D), St. Lawrence TS (L24A), Chats Falls TS (C3S) and Almonte TS (E34M), providing supply from broader provincial resources.

Under normal operating conditions, the Ottawa load is primarily supplied by the two 500 kV circuits from Lennox TS. However, when these two primary supply circuits are unavailable, the Ottawa load relies on the 230 kV electricity system to supply the load. The FIO interface is thermally limited by the 230 kV circuit L24A from St. Lawrence TS to Hawthorne TS, and the upstream 230 kV circuit P15C from Cherrywood TS to Dobbin TS. In the existing system, the load meeting capability of Ottawa is limited to 1700 MW today due to thermal limitations. While not the most limiting, Ottawa's load meeting capability is also limited by voltage instability. Information regarding Ottawa's load meeting capability and limiting phenomena is shown in Table 3.

⁴ The region also has a significant number of distribution connected resources, mainly hydro-electric and solar. The impact of these distributed resources has been considered as part of the reference load forecast.

Ottawa is also interconnected with Quebec through three (3) 230 kV interconnections and three (3) 115 kV interconnections. The six interties facilitate mostly economic energy transactions between Ontario and Quebec through the Ontario electricity market. The current interties between Quebec and Ontario have a combined capacity of 2,775 MW; however, transmission constraints in Ontario limit the available transfer capability between the two areas⁵. Real-time transactions with Quebec have reached a maximum of about 1,800 MW.

Table 3 | Ottawa Load Meeting Capability

Transmission Equipment Out of Service	Phenomena	Ottawa LMC
Loss of X522A & X523A	Thermal overload on P15C	1700
Loss of X522A & X523A	Voltage Instability	1800

⁵ More information about the Ontario-Quebec interconnection is available in the IESO's 2017 report – "Ontario-Quebec Interconnection Capability: A Technical Review" ([link](#))

6. Need for Additional Supply

The IESO has conducted an assessment of the system's capability to supply the areas of Peterborough to Quinte West and Ottawa. Planning criteria were applied in accordance with North American Electric Reliability Corporation standards and the Northeast Power Coordinating Council reliability directories to determine system capacity needs. In the context of the bulk system, adequacy is defined as the ability to supply regional demand, while respecting transfer capability limits across the bulk system and interconnections.

This assessment considered both the contribution of existing internal generation and resources external to the area.

6.1 Capacity Requirement

A deterministic approach was used to evaluate the need for additional capacity behind the Flow into Dobbin and Sidney, and Flow into Ottawa interfaces. A need was identified where the annual coincident load forecast exceeded the interface transfer limits and the total capacity of internal transmission-connected generation.

6.1.1 Flow into Dobbin and Sidney

Based on this assessment, to supply Peterborough to Quinte West there is a capacity need of 100 MW in the summer by 2035. The capacity need is an existing issue, that arises during periods of high demand coinciding with low water conditions. The annual capacity requirement for FIDS is shown in Figure 5.

In addition to the annual capacity shortfall, the estimated frequency, duration, and magnitude of unserved energy events were also investigated and used to inform options development. Figure 6 contains heat maps to visually demonstrate these characteristics. Each cell in the heat map indicates the expected frequency, of all hours of unserved energy, that may occur in that specific hour or month. By 2035, unserved energy is expected to occur mostly in the months of April through October, with the largest impact observed during the summer peaks.

There is a significant amount of distribution connected solar generation within the Peterborough to Quinte West area. The effects of the solar generation can be seen in the heat maps, as the solar generation helps offset the demand during the hours of 8:00 AM to 5:00 PM and reduces the energy needs during those hours.

Figure 5 | Flow into Dobbin and Sidney Capacity Requirement

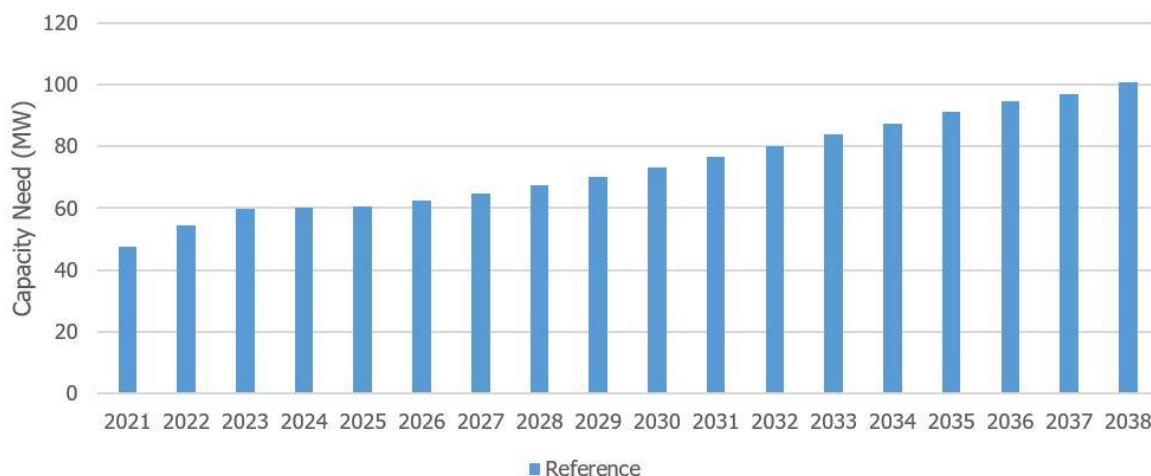
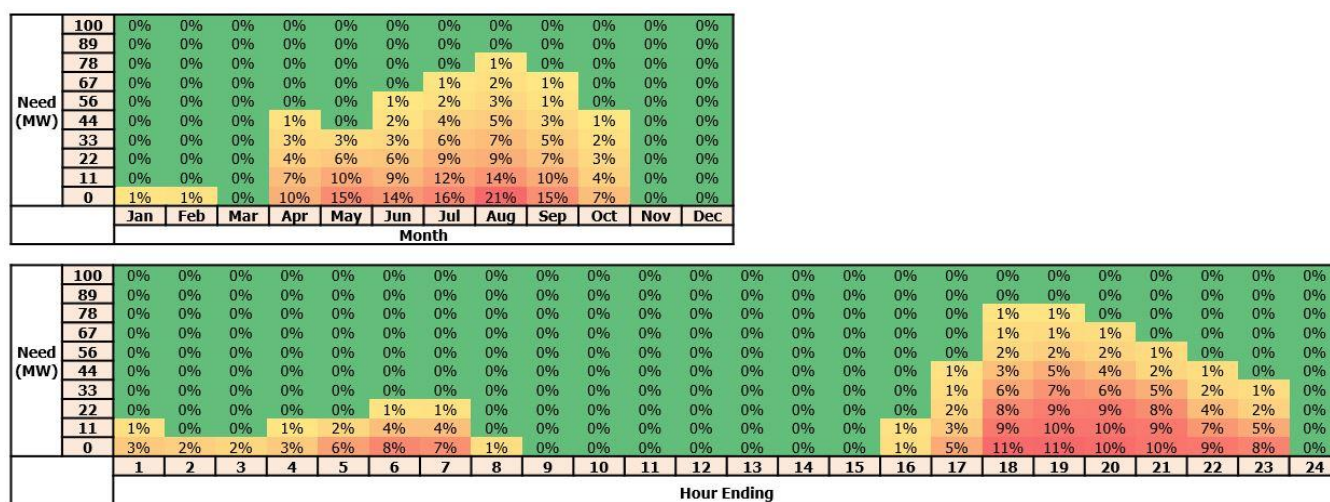


Figure 6 | Heat Maps Showing Possible Energy Need behind FIDS in 2035



6.1.2 Flow into Ottawa

Based on this assessment, a capacity need first emerges in 2025 and grows to 475 MW in the summer by 2042 under the reference scenario. Under the high growth scenario, the capacity need increases to 625 MW by 2042. When considering generation coming off contract, the capacity need becomes 550 MW and 700 MW respectively (approximately 75 MW of transmission connected generation coming off contract during the 20 year planning horizon). The annual capacity requirement is shown in Figure 7. In addition to the annual capacity shortfall, the estimated frequency, duration, and magnitude of unserved energy events were also investigated and used to inform options development. Figure 8 contains heat maps to visually demonstrate these characteristics. While Ottawa is a summer peaking area today, its expected that Ottawa will gradually shift to being winter peaking over the next 20 years due to decarbonisation efforts.

Figure 7 - Flow into Ottawa Capacity Requirement

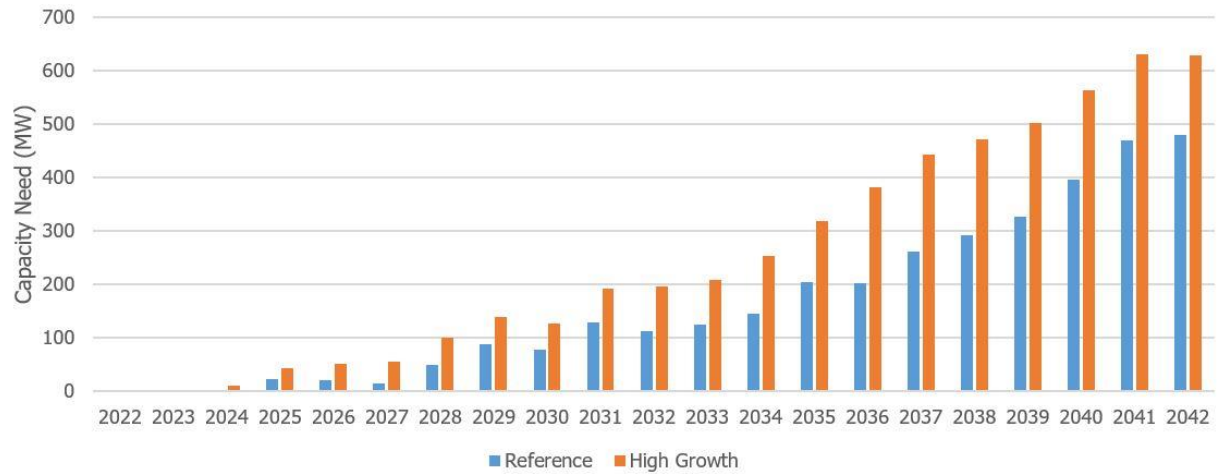
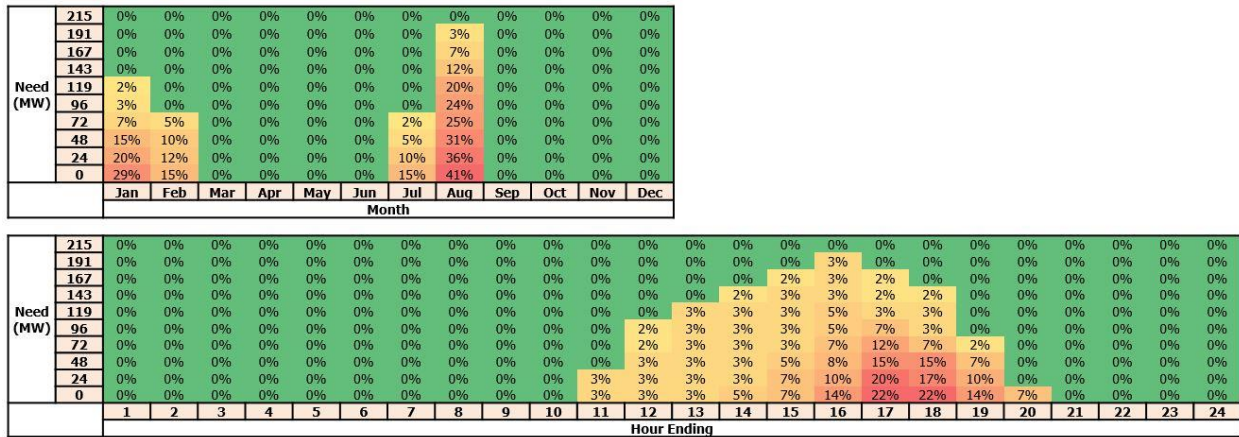


Figure 8 | Heat Maps Showing Possible Energy Need behind FIO in 2035



7. Analysis of Alternatives

This study compares alternatives to meeting the identified near-, mid-, to long-term supply capacity requirements for the areas of Peterborough to Quinte West and Ottawa. The alternatives considered include both traditional transmission wires type reinforcements aimed at improving the FIDS and FIO interface transfer limits as well as non-wire alternatives (NWAs) such as generation, battery energy storage systems (BESS), demand response, etc.

Non-wire Alternatives

For each need where NWAs are potentially suitable, the demand profiling methodology is used to characterize the need and inform options analysis. The development of NWAs takes into consideration a number of factors, such as:

- Maximizing the use of existing infrastructure and resources in the region (e.g., merchant generation, generators with expiring contracts, etc.) to defer transmission and/or generation investment.
- New generation and/or storage with the attributes that most closely meet the need, or integrated solutions in combination with demand response or energy efficiency measures.
- New transmission facilities to deliver provincial resources.

NWA selection is based on capacity (MW) and energy requirements (MWh). The need characteristics are quantified by capacity factors and the energy-not-served (ENS) profile which is the forecast hourly demand above the load meeting capability that can be served by the existing power system in a specified area. The ENS profile is not static over the planning horizon, allowing NWAs to be installed in modular and discrete blocks as demand grows. Transmission solutions and non-energy-limited resources can primarily be sized based on the power capacity requirements alone, however energy-limited resources must also consider the energy requirement and temporal patterns. For example, BESS must be sized such that the energy reservoir has enough storage capability to withdraw enough energy overnight, and inject it the next day with enough capacity to meet demand.

The capacity and energy requirements evolve as demand grows and influences the feasibility and economics of various NWAs. In general, potential options that are known to satisfy technical requirements and have the lowest cost tend to be screened for suitability first. The NWA should aim to cost-effectively meet the need on an equivalent dollar and reliability basis. Calculating the levelized unit capacity cost provides a means of assessing alternative options for planning purposes and is generally used as a screening tool to shortlist resources for more detailed analysis. The calculation considers factors such as overnight capital costs, fixed operating, maintenance and administrative (OM&A) costs, variable OM&A costs, etc.) amortized across the NWAs lifetime.

Cost estimates for NWAs are based on benchmark capital and operating cost characteristics for each resource type and size. Generally speaking, the most cost-effective transmission-connected options for meeting local needs are resources with costs on par with simple cycle gas turbines (SCGT) generators or BESS, depending on the relative size of the facility and the capacity factor. New natural gas-fired generation was considered in the economic analysis for illustrative purposes to represent the cost of new generation. BESS are also becoming cost competitive due to declining technology costs and the expectation of carbon prices increasing in line with federal policy.

NWAs also provide bulk system capacity and energy benefits and are taken into consideration as part of the cost analysis. Bulk system capacity benefits are considered in each year capacity is required and is based on the capacity auction reference price. The reference price is the estimated Net Cost of New Entry (Net CONE) of the anticipated lowest cost marginal resource in Ontario that would be developed when new generation is required. Bulk system energy benefits are considered for any instance where the NWA displaces higher marginal cost resources.

Energy Efficiency

Energy efficiency is a low cost resource that offers tremendous benefits for individuals, businesses and the power system as a whole. Energy-efficiency programs help reduce the need for new investments in power plants and transmission lines.

The IESO offers a number of Conservation and Demand Management (CDM) programs as part of the 2021-2024 [CDM Framework](#) under the [Save on Energy brand](#). In order to address regional and local system needs, the IESO can also assess the potential for savings opportunities incremental to these current initiatives that are cost effective based on system benefits and can be leveraged to help defer or compliment wires infrastructure and ensure system reliability.

As described in Section 6, a capacity requirement exists in Peterborough to Quinte West area today and is forecast to appear in the Ottawa area by 2025. As the timing of the needs are in the near-term and with the magnitude of the needs being substantial (upwards of 100 MW within the first 10 years), incremental energy efficiency was considered in this assessment as a potential compliment to other solutions, not as a stand-alone solution.

7.1 Alternatives Considered

In total there were six packages of solutions put together to form the basis of the alternatives considered. Each package comprises of a combination of solutions described in this report. The packages are shown in Table 4 **Error! Reference source not found..**

Table 4 | Gatineau Corridor EOL Study Solution Packages

T22C & T33E	Peterborough to Quinte West Area Improvements	Peterborough to Quinte West LMC	Ottawa Area Improvements	Ottawa LMC	Cost (2021 \$M)
1 Refurbish	Two 230 kV circuits from Dobbin TS to Clarington TS/Cherrywood TS	440 MW	Pursue targeted energy efficiency	1950 MW	\$600M-\$650M
2 Retire	Two 230 kV circuits from Dobbin TS to Clarington TS/Cherrywood TS	440 MW	Two 230 kV circuits from St. Lawrence TS to Merivale TS Pursue targeted energy efficiency	2050 MW	\$725M-\$775M
3 Retire	Two 230 kV circuits from Dobbin TS to Clarington TS/Cherrywood TS	440 MW	One 500 kV circuit from St. Lawrence TS to Hawthorne TS	2150 MW	\$875M-\$925M
4 Refurbish	175 MW resource at/near Dobbin TS	390 MW	Pursue targeted energy efficiency	1950 MW	\$1,150M-\$2,000M
5 Retire	Two 230 kV circuits from Dobbin TS to Clarington TS/Cherrywood TS	440 MW	480 MW resource at/near Hawthorne TS	2180 MW	\$875M-\$1,725M
6 Retire	225 MW resource at/near Dobbin TS	390 MW	480 MW resource at/near Hawthorne TS	2180 MW	\$2,150M-\$4,150M

Transmission Reinforcement into Peterborough

Transmission reinforcement into Peterborough involves a new transmission line between Dobbin TS in Peterborough and either Cherrywood TS in Pickering or Clarington TS in Oshawa. With four (4) 230 kV transmission circuits interconnecting Cherrywood TS and Clarington TS, and the presence of 500-230 kV auto-transformation at both stations, the two stations are quite similar from an electrical supply perspective.

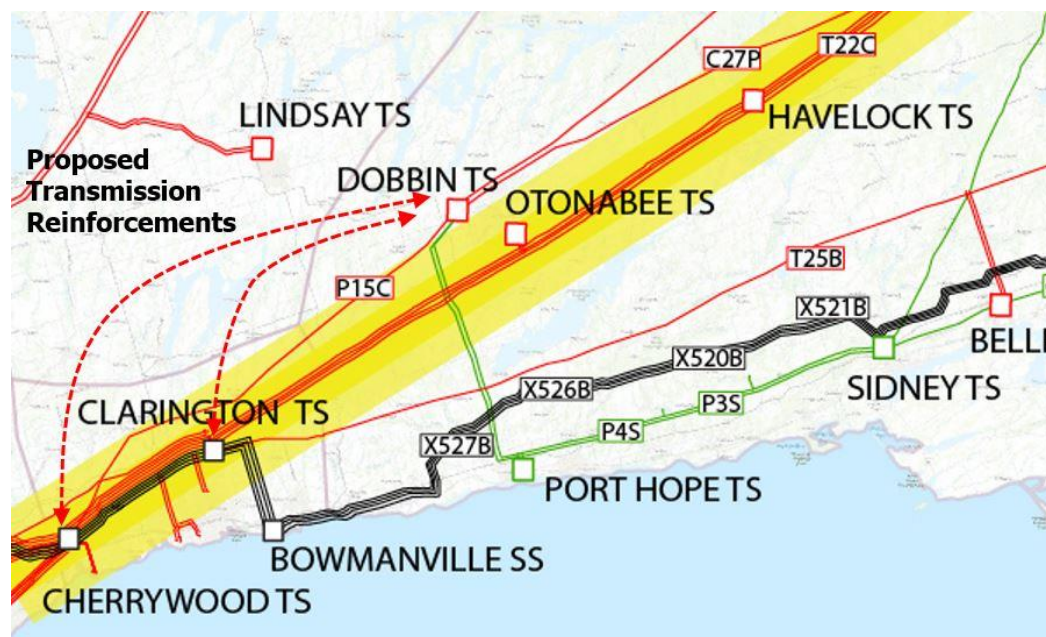
There are different variations to how this transmission reinforcement could be achieved. Each variation comparably increases the Peterborough to Quinte West LMC to approximately 440 MW. This improved capability sufficiently accommodates the 20-year planning forecast which reaches a maximum of 370 MW. As such, in addition to accommodating the planning forecast, the transmission reinforcement alternative provides additional flexibility and resiliency in meeting future changes in demand. The transmission reinforcement into Peterborough also mitigates the upstream thermal constraints limiting Ottawa for the duration of the 20-year planning forecast.

The variations of this transmission reinforcement include:

- Rebuild an existing single circuit 230 kV line from Cherrywood TS (Pickering) to Dobbin TS (Peterborough) into a double circuit 230 kV line
- Build a new double circuit 230 kV transmission line from Cherrywood (Pickering) TS to Dobbin TS
- Build a new double circuit 230 kV transmission line from Clarington TS (Oshawa) to Dobbin TS

A map showing the transmission reinforcement to Peterborough is shown in Figure 9.

Figure 9 | Map of Proposed Transmission Reinforcement Options into Peterborough



As the variations are currently comparable from a cost, scope⁶, and capability perspective, each variation should be further examined during the project development and project approval stages led by the transmitter⁷ in order to select the preferred variation.

Resource in Peterborough to Quinte West

A new resource located in the Peterborough to Quinte West area was considered as a NWA to the transmission reinforcement into Peterborough. The resource requirements can range depending on whether the transmission lines T22C and T33E are refurbished or decommissioned. Decommissioning the transmission lines will increase the flows from GTA east to Ottawa and through the P15C and C27P transmission lines. The analysis identified a SCGT facility (175 MW) as the most feasible non-wire alternative if T22C/T33E are refurbished. Alternatively, the analysis identified a CCGT (225 MW) as the most feasible non-wire alternative if T22C/T33E are decommissioned. Additional alternatives involving hybrid BESS and wind were also examined. A BESS solution would be deployed modularly in discrete blocks as demand grows.

Refurbishment of T22C and T33E into Ottawa

This option involves refurbishing the EOL transmission lines T22C from Clarington TS to Chats Falls TS, and T33E from Clarington TS to Almonte TS. While this option appears to maintain the existing transmission supply to Ottawa, the LMC for Ottawa is improved to 1950 MW through the addition of a new RAS, and the mitigation of the upstream thermal limitations on P15C through either the transmission reinforcement into Peterborough or a new resource in the Peterborough to Quinte West area. A new LMC of 1950 MW accommodates the forecast demand in Ottawa up to year 2037 based on the reference forecast.

Transmission Reinforcement into Ottawa

The transmission reinforcement into Ottawa involves a new transmission line between St. Lawrence TS in Cornwall and either Merivale TS (230 kV transmission line) or Hawthorne TS (500 kV transmission line) which are both in Ottawa. The two variations to how this transmission reinforcement can be achieved are comparable as they both strengthen the tie between the Ottawa area and the Cornwall area which has a sizeable amount of hydro-electric generation. The variations of this transmission reinforcement include:

- Build a new double circuit 230 kV transmission line from St. Lawrence TS (Cornwall) to Merivale TS (Ottawa)
- Build a new single circuit 500 kV transmission line from St. Lawrence TS (Cornwall) to Hawthorne TS (Ottawa)

⁶ A new transmission line originating from Cherrywood TS is assumed to repurpose existing breaker positions at Cherrywood TS currently serving Pickering GS which is planned for retirement between 2024-2026.

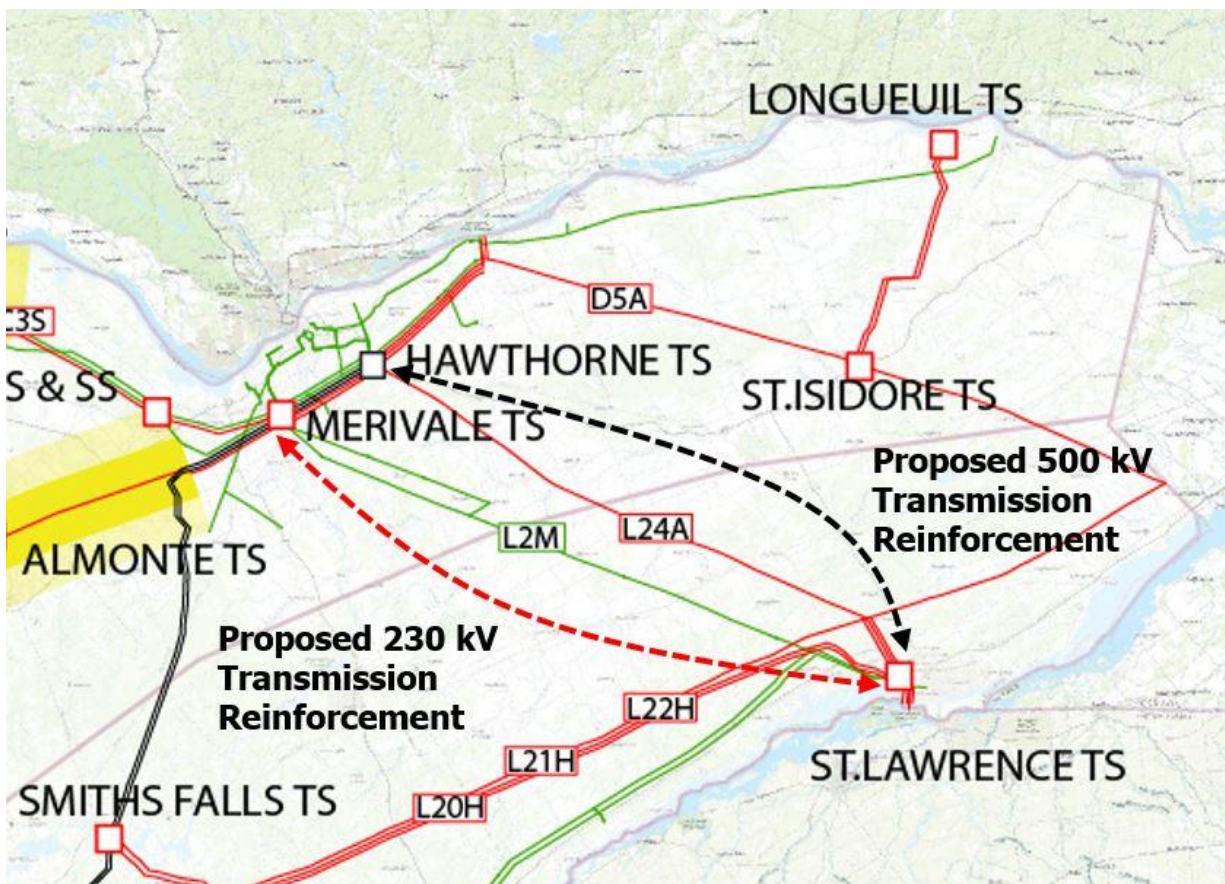
⁷ New transmission lines in Ontario are subject to the Environmental Assessments ("EA") Process where line routing will be assessed and evaluated, interested parties will have an opportunity to provide input on line routing to the transmitter as part of the EA (Ontario Government Website [link](#))

Both variations enable the opportunity for decommissioning the two EOL transmission lines T22C and T33E. The variations are quite comparable to each other, the 500 kV transmission line option offers an incremental capacity improvement of 100 MW at an incremental cost of approximately \$150M.

A new 230 kV transmission line into Merivale TS will increase the Ottawa LMC to 2050 MW which will accommodate the forecasted demand in Ottawa up to year 2039, while a new 500 kV transmission line into Hawthorne TS increases the Ottawa LMC to 2150 MW which will accommodate the forecasted demand in Ottawa up to year 2041.

A map showing the Ottawa transmission reinforcements is shown in Figure 10.

Figure 10 | Map of Transmission Reinforcement Options for Ottawa



Resource in Ottawa

A new resource located in the Ottawa area was considered as a NWA to the refurbishment of T22C/T33E or the transmission reinforcement into Ottawa. The analysis identified a SCGT facility (480 MW) as the most feasible non-wire alternative. Additional alternatives involving hybrid BESS and wind were also examined. A BESS solution would be deployed modularly in discrete blocks as demand grows.

For all solution packages, a Remedial Action Scheme (RAS) will be relied upon to help accommodate the forecasted demand. RASs (formerly named Special Protection Systems) are utilized to expand the capability of the transmission system and maximize the benefits of the transmission system equipment. The use of RAS's are governed by applicable planning criteria⁸. The two RASs identified, one for Peterborough to Quinte West and another for Ottawa, are both load rejection based schemes that will disconnect up to 150 MW when two or more power system elements are out of service (i.e. two transmission circuits are unavailable). Load rejection or load shedding schemes exists in both areas today, however the schemes will require modifications/updates to accommodate the forecasted demand.

7.2 Energy Efficiency

As discussed earlier, incremental energy efficiency was considered in this assessment as a compliment to other solutions. This section aims to quantify the energy efficiency opportunities in Ottawa.

In 2019, the IESO and the Ontario Energy Board completed the first integrated electricity and natural gas achievable potential study in Ontario (2019 APS)⁹. The main objective of the APS was to identify and quantify energy savings (electricity and natural gas) potential, GHG emission reductions and associated costs from demand side resources for the period from 2019-2038. The study shows a significant and sustained potential for energy efficiency across all sectors and is used to inform:

- future energy efficiency policy and/or frameworks;
- program design and implementation; and
- assessments of Conservation and Demand Management (CDM) non-wires potential in regional planning.

The APS study is used to determine an estimate of the remaining system cost-effective energy efficiency potential for planning study areas when accounting for existing provincial programs, federal program and savings from codes and standards.

In order to determine which needs should be evaluated for the use of energy efficiency as a solution, a screening mechanism was applied, in accordance with the IESO's standard criteria which includes consideration of factors such as the timing and magnitude of the need, its size relative to total forecasted demand, and coincidence with provincial system peak. The potential for energy efficiency to help address the identified needs was assessed for the Ottawa area supply capacity need, but not the Peterborough to Quinte West need, due to the timing and magnitude of the need identified.

⁸ Usage of RAS is governed by IESO's Ontario Resource Transmission Assessment Criteria ([link](#)), NERC's Transmission System Planning Performance Requirements – ([link](#)), and NPCC's Directory # 1 Design and Operation of the Bulk Power System ([link](#)).

⁹ More information about the 2019 Conservation Achievable Potential Study is available on the IESO website ([link](#))

7.2.1 Energy Efficiency Potential in Ottawa

As part of the analysis developed for the 2020 Integrated Regional Resource Plan for the Ottawa sub-region, the IESO estimated that energy efficiency has the potential to reduce demand by approximate 1% per year on average in the Ottawa zone based on the 2019 APS results. These opportunities are reduced in the near term by existing CDM commitments while new opportunities increase in the medium term, following conclusion of the 2021-2024 CDM framework. The cumulative maximum achievable potential savings is shown in Figure 11 and Figure 12.

Note that the portion of the maximum achievable potential that is committed is included in the planning forecast shown in Figure 4.

Figure 11 | Cumulative Maximum Achievable Zonal Potential as a Share of Consumption

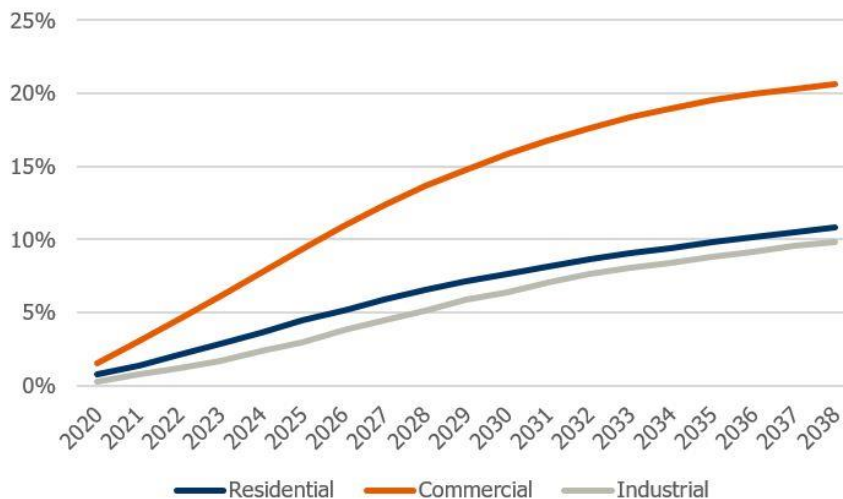
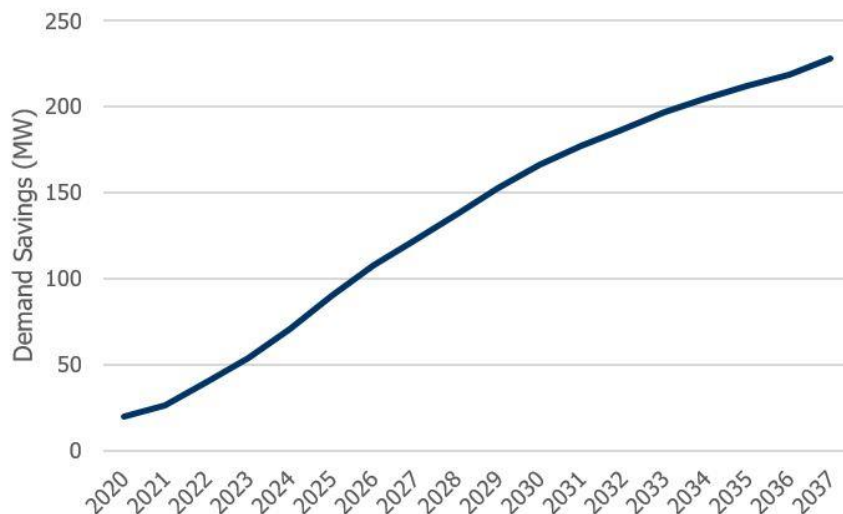


Figure 12 | Cumulative Maximum Achievable Zonal Potential as a Share of Consumption Net of Committed Savings

Uncommitted cumulative CDM potential that is cost effective based on avoided provincial system energy and capacity costs for stations within the FIO interface is presented in Figure 13. The estimated cost to deliver these savings is \$587 million dollars over the forecast period.

Figure 13 | Uncommitted CDM Potential in Ottawa



Ongoing Energy Efficiency Activities in Ottawa

The IESO is currently delivering province-wide Save on Energy-branded CDM programs in the Ottawa area as part of the 2021-2024 CDM Framework to encourage the adoption of energy efficiency process and technologies in businesses and communities.

Additionally, as part of the 2021-2024 CDM Framework,¹⁰ the IESO was directed to deliver a new competitive program to target additional CDM incremental to the province-wide programs to address regional and/or local system needs. The Local Initiative Program,¹¹ is now one tool that is available to target the delivery of additional CDM savings at specific areas of the province with identified system needs. The IESO is currently working with Hydro Ottawa to develop a Local Initiative Program procurement in order to begin targeting incremental savings opportunities described above and previously highlighted in the 2020 Ottawa IRRP.

As part of the 2021-2024 CDM Framework Mid-Term Review¹² published in December 2022, the IESO reviewed the scale of the opportunity for CDM to be targeted to address regional or local needs, available tools for targeting CDM, and the opportunities for LDCs to building on IESO CDM programs where they can add value to the distribution system. Based on accelerated findings, the Minister of Energy approved a number of IESO recommendations in October 2022, including Local Initiative Program enhancements to reduce barriers to participation and to add flexibility for incentives for DER solutions. The IESO should continue to explore opportunities to target savings in the Ottawa and Peterborough to Quinte regions in order to help address these emerging bulk and regional system needs.

¹⁰ More information about the 2021-2024 CDM Framework is available on the IESO website ([link](#)).

¹¹ More information about the Local Initiative Program is available on the IESO website ([link](#)).

¹² More information about the 2021-2024 CDM Framework Mid-Term Review is available on the IESO website ([link](#)).

7.3 Comparison of Alternatives

7.3.1 Technical Comparison

A transmission reinforcement to Dobbin TS in Peterborough, regardless of whether the transmission line comes from Cherrywood TS in Pickering or Clarington TS in Oshawa, accommodates the 20-year long-term forecast for Peterborough to Quinte West. In addition, the transmission reinforcement provides an additional 70 MW of supply capacity for the area beyond the current demand forecast. This margin will allow for additional growth beyond the forecast and enables the area to better respond to demand forecast changes (i.e. greater penetration of electrification, industrial/manufacturing growth).

Furthermore, the current limiting constraint to Ottawa's LMC is the upstream thermal overload of P15C. The transmission reinforcement to Dobbin TS in Peterborough not only addresses the Peterborough to Quinte West need, but also addresses this upstream thermal limitation for Ottawa.

Lastly, if the proposed transmission reinforcement originates from Cherrywood TS in Pickering, the new transmission line may potentially benefit new load connections in the northern areas of Pickering, Whitby, and Oshawa around and north of highway 407 further into the future.

In comparison, the resource alternative to address this upstream thermal overload will require a resource between 175 and 225 MW, which will need to run frequently (30% of hours by year 10 of the forecast and 80% of hours by year 20 of the forecast). The analysis considered a CCGT facility and hybrid storage facility (BESS with wind) as the most feasible NWA alternatives due to the energy requirements.

With the upstream thermal overload of P15C resolved, either by the transmission reinforcement to Dobbin TS or the resource alternative, the focus becomes addressing the voltage instability issue and the forecast capacity requirements in Ottawa. Refurbishing the EOL transmission lines T22C and T33E mostly maintains the status quo. The improvement in the LMC to 1950 MW is mostly attributed to mitigating the upstream thermal overload of P15C and the addition of a load rejection RAS in Ottawa.

The second transmission alternative, building a new double circuit 230 kV transmission line from St. Lawrence TS in Cornwall to Merivale TS in Ottawa provides a small improvement to the voltage instability issue and increases the Ottawa LMC to 2050 MW. While this alternative introduces a new 230 kV supply into west Ottawa which would help in the resiliency of supplying west Ottawa loads, by not refurbishing T22C and T33E, part of that improvement is counteracted by the decommissioning.

The third transmission alternative, building a new single circuit 500 kV transmission line from St. Lawrence TS in Cornwall to Hawthorne TS in Ottawa, provides another small improvement to the voltage instability issue and increases the Ottawa LMC to 2150 MW.

The three transmission alternatives result in varying Ottawa LMCs of 1950, 2050, and 2150 MW. With the three alternatives, the improvement in LMC will be able to accommodate the reference Ottawa demand forecast up to year 2037, 2039, and 2041 respectively. While the alternative to refurbish T22C and T33E results in the lowest Ottawa LMC out of the three, maintaining the status quo helps preserve the capacity that T22C and T33E provides to Ottawa, which in the future can be combined with a new transmission line reinforcing Ottawa that may be needed in the future to accommodate a high growth scenario (i.e. such as electrification).

The resource alternative is sized to meet the demand forecast. Depending on the technology, if a BESS were implemented, the resource could also be installed in modules as the demand grows.

7.3.2 Cost Comparison

The IESO compared the net present value (NPV 2021\$) of total costs and benefits for various alternatives required to address the Peterborough to Quinte West and Ottawa supply capacity requirements.

This economic evaluation was based on available cost estimates for similar sized resources and planning estimates for the proposed transmission facilities constructed based on similar past projects. The costs for each solution package are summarized in Table 4. More information regarding cost assumptions is described in Appendix D.

The three transmission only packages (1 through 3) are very comparable in cost, with incremental steps in cost resulting in incremental steps in supply capacity for Ottawa.

The three other packages (4 through 6) represent a hybrid comprising of both transmission and resources (SCGT/CCGT, BESS, and wind) and also an all resources based solution (SCGT/CCGT, BESS, and wind). The wide range in costs shown here reflects the cost difference between a SCGT/CCGT and a BESS and wind combination.

As mentioned earlier, both NWSs and EE provide bulk system capacity and energy benefits and have been taken into consideration as part of the cost analysis.

Based on the technical and cost comparison presented in this section, the IESO recommends solution package #1 to address the EOL needs in the Gatineau corridor and the supply capacity needs in Peterborough to Quinte West and Ottawa. This is further described in section 10 of the report.

8. Linkages with Regional Planning

Bulk system planning as shown in Figure 14 is just one form of electricity planning that is undertaken in Ontario, with the others being regional planning and distribution planning.

Figure 14 | Electricity Planning in Ontario



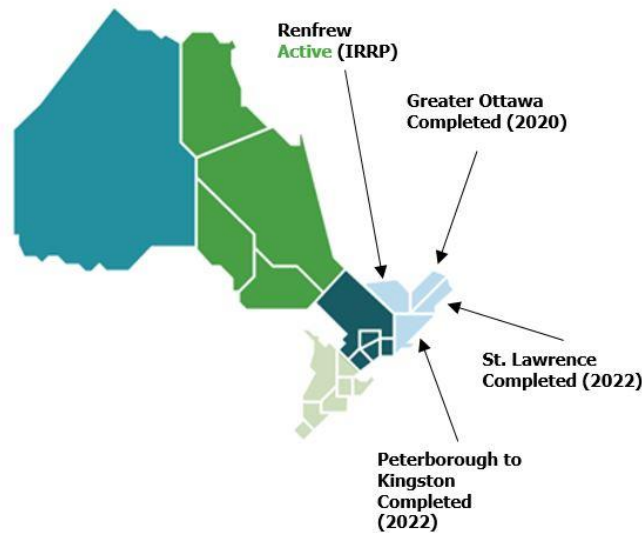
Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. In addition to considering major transmission facilities or “wires,” bulk system planning assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO pursuant to government policy. Distribution planning, which is carried out by local distribution companies (LDCs), considers specific investments in an LDC’s territory at distribution-level voltages.

Regional planning can overlap with bulk system planning and with the distribution planning of LDCs. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue or when a distribution solution addresses the needs of the broader local area or region, making it important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages between bulk, regional and distribution system planning, and coordinating the multiple needs identified over the long term, a comprehensive assessment of electricity needs can be carried out to develop integrated solutions that can address multiple needs.

As a result of the Gatineau corridor being approximately 350 km long, it has linkages with a number of different regions in southern Ontario including Greater Toronto Area East, Peterborough to Kingston, Renfrew, and Ottawa. In this section, key linkages to some of these regions are described. A map illustrating the 21 planning regions in Ontario is shown in Figure 15, with the regions in the east highlighted.

Figure 15 | Planning Regions in Eastern Ontario



8.1 Peterborough to Kingston Region

Regional planning for Peterborough to Kingston was most recently completed in May 2022. This was the first cycle of regional planning for Peterborough to Kingston to reach the integrated regional resource planning and regional infrastructure planning stage where a more in depth examination of power system needs was carried out.

The regional studies identified transmission system issues that have linkages with the upstream transmission system and specifically the Gatineau Corridor EOL Study. The recommended option also addresses the voltage issues on the 115 kV system identified in the 2021 Peterborough to Kingston IRRP¹³.

In addition to the coordinated approach to issue identification, the regional planning activities allowed the IESO to obtain very detailed load forecasts that were developed by the Peterborough to Kingston regional planning working group along with valuable insight from the local distributors. The Peterborough to Kingston regional planning load forecast directly informed the load forecast used for the Peterborough to Quinte West area in the Gatineau Corridor End-of-Life study.

8.2 Greater Ottawa Region

Regional planning for Greater Ottawa was most recently completed in December 2020. Through those regional studies, capacity issues with the bulk transmission supply to the Ottawa 115 kV system were identified. This led to a series of near-term actions being recommended through the Ottawa Area IRRP which included:

¹³More information about these transmission issues are available in section 6 of the Peterborough to Kingston IRRP ([link](#)).

- Advancing the EOL replacement of the 230-115 kV auto-transformer T22 at Merivale TS which will result in a slightly higher supply capacity
- Triggering of a broader Ottawa 115 kV System Study to be carried out by the IESO (study ongoing)
- Pursue system cost effective energy efficiency in the Ottawa 115 kV system area

In recent months, through discussion with the Greater Ottawa regional planning working group, the IESO was informed of substantial load growth emerging in various areas across the City of Ottawa. The size and aggressive timing of the load growth resulted in the working group's decision to trigger the next cycle of regional planning early (expected to commence in Q4 2022).

Through the next cycle of regional planning, a new detailed 20-year planning forecast will be developed to assess transmission system supplying Greater Ottawa. Further, as described earlier in section 4.2, Ottawa's city council approved the Energy Evolution strategy on October 28, 2020. The impact of Energy Evolution on the peak electricity demand has yet to be quantified and has not been incorporated into the various bulk or regional planning forecasts. The impacts of Energy Evolution on electricity demand will be further explored as part of this next cycle of regional planning.

Depending on the outcomes of regional planning, additional reinforcements to the bulk transmission system may need to be triggered earlier than currently forecast.

8.3 Greater Toronto Area East

One of the alternatives to addressing the supply capacity issues for Peterborough to Quinte West involves a new transmission line between Dobbin TS in Peterborough and either Cherrywood TS in Pickering or Clarington TS in Oshawa. As indicated in section 7.3.1 the two stations Clarington TS and Cherrywood TS are electrically quite similar in terms of their ability to provide capacity improvements to the Peterborough to Quinte West areas.

However, the option to terminate at Cherrywood TS may have the added benefit of improving the load meeting capability of the local area, namely northern Pickering and Whitby. Based on recent discussion between the IESO and Elexicon Energy, the LDC for this area, updated growth forecasts may trigger the need for additional supply meeting capability in the mid term.

Although growth rates and preferred alternatives for meeting any ensuing needs have not been established through the regional planning process, the Cherrywood connection option offers additional flexibility by accommodating a greater range of future load growth scenarios.

The IESO will continue discussions with the GTA East regional working group members to determine if there is need to trigger the next cycle of regional planning early.

9. Engagement

The IESO has developed and is transitioning to a formalized process¹⁴ for bulk system planning to enhance transparency and opportunities for purposeful engagement and input. As part of that work, defining how stakeholders can participate in the electricity planning process and be kept informed has been identified as a critical component of the process design. Providing opportunities for input in the transmission planning process enables the views and preferences of communities and stakeholders to be considered in the development of the plan, and helps lay the foundation for successful implementation. The IESO has endeavored to encompass those principles throughout the Gatineau Corridor EOL study work. This section outlines the engagement principles as well as the activities

9.1 Engagement Principles

The IESO's engagement principles¹⁵ help ensure that all interested parties are kept informed and enables opportunities for purposeful engagement to contribute to electricity planning initiatives such as the development of this Gatineau Corridor EOL planning study. The IESO adheres to these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 16 | The IESO's Engagement Principles



¹⁴ More information about the bulk planning process is available on the IESO website ([link](#)).

¹⁵ More information about the IESO's engagement principles are available on the IESO website ([link](#)).

9.2 Engagement Approach

To ensure that the bulk plan reflects the needs of Indigenous communities, community members and interested stakeholders, engagement involved:

- Leveraging the East Ontario Bulk Planning Initiatives¹⁶ engagement webpage on the IESO website to post updated information, engagement opportunities, meeting materials, input received and IESO responses to the feedback;
- Regular communication with communities, stakeholders and interested parties through email, East Ontario Electricity Network updates¹⁷, and IESO weekly Bulletin;
- Public webinars; and
- Targeted outreach throughout plan development with municipalities, customers, Indigenous communities and rights-holders, and those with an identified interest in the Gatineau Corridor area.

The Gatineau Corridor EOL study was initiated prior to the IESO implementing a formalized bulk planning process. However, as part of implementation of the new process, three public webinars (two targeting all interested parties and one specifically targeting Indigenous Communities) were held at the remaining major junctures of plan development to give interested parties an opportunity to understand the scope of the study and provide comments on the proposed recommendations.

The webinars received strong participation with cross-representation of stakeholders and municipal and Indigenous community representatives in attendance, and submitting written feedback during a 21-day comment period.

Comments received during this engagement focused on the following major themes:

- **Forecast Risk in Ottawa:** Interest was expressed in better understanding how the study will ensure that Ottawa is positioned to meet emerging electricity needs, in particular needs driven by the City's decarbonisation plans.
- **Resource Cost Assumptions:** Feedback received indicated that updated market information should be incorporated into the study's cost assumptions. A suggestion was provided that the upcoming procurements may allow the IESO to gain a better sense of the current cost of storage for use in future assessments.
- **Scope of Transmission Alternatives:** Questions from engagement participants indicated a general desire to better understand the scoping of the study, and the associated options analysis. In particular, interested parties wanted to understand why the IESO did not consider various wires and non-wire alternative transmission options as part of the study.
- **Consideration of Emerging Growth in GTA East:** Targeted outreach with Elexicon and Durham Region identified emerging load growth in north Whitby that may trigger new load station development.

Based on the engagement discussions and feedback received, it is clear that interested parties want to ensure that the IESO is incorporating the best available information into the study analysis and

¹⁶ More information about East Ontario Bulk Planning Initiatives is available on the IESO website ([link](#)).

¹⁷ More information about the East Ontario Electricity Network is available on the IESO website ([link](#)).

recommendation so that the final recommendation meets Ontario's future electricity needs and priorities. Section 7 of the report includes the analysis of alternatives.

The bulk planning process is continuing to evolve. The IESO will work to increase transparency and cost discovery around transmission versus generation decision making as resource acquisition mechanisms continue to mature. Outcomes of this engagement will also be incorporated in other related electricity planning work and regional planning processes, such as the next GTA East regional planning cycle.

All background information, including engagement meeting presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's East Ontario Bulk Planning Initiatives engagement webpage.

9.3 Bringing Communities to the Table

The IESO held meetings with communities to seek input on local planning priorities and initiatives that should be taken into consideration in the development of this bulk plan. At major milestones in the study development process, targeted discussions were held with the upper- and lower-tier municipalities both in the East Ontario planning regions as well as in the adjacent GTA East planning area to discuss study recommendations. These meetings helped to inform electricity needs at the municipal/community-level, develop options and recommended solutions, and further build and strengthen local relationships for ongoing dialogue beyond this bulk process.

9.4 Engaging with Indigenous Communities

As part of the engagement process, the IESO reached out to Indigenous communities in and near the Eastern Ontario planning area throughout the development of the plan. Those invited to participate included: Alderville; Algonquins of Ontario (AOO Consultation Office); Algonquins of Pikwakanagan; Association of Iroquois and Allied Indians; Beausoleil; Chippewas of Georgina Island; Chippewas of Rama; Curve Lake; Haudenosaunee Confederacy Chiefs Council; Haudenosaunee Development Institute; Hiawatha; Huron-Wendat Nation; Mississaugas of Scugog Island; Mohawk Council of Akwesasne; Mohawks of the Bay of Quinte; Ogemawahj Tribal Council; MNO High Land Waters Métis Council; MNO Oshawa and Durham Region Métis Council; MNO Ottawa Region Métis Council; and MNO Peterborough and District Wapiti Métis Council.

A webinar for Indigenous communities was held on April 13, 2022. To ensure the invited communities had ample opportunity to participate, after the webinar concluded the presentation deck was emailed to them along with an invitation and registration information for a general webinar that was held on April 14, 2022. Feedback was received from the Haudenosaunee Development Institute which was posted along with the other received feedback on the IESO's engagement page for Bulk Electricity Planning - East Ontario under the entry for May 5, 2022. A general webinar was held on August 11, 2022, an invitation email was sent to the communities on July 19. A link to the materials for East Ontario planning was included and communities were informed that a feedback/comment period would be open until September 1, 2022.

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

10. Conclusions and Recommendations

To minimize cost, minimize land-use impacts, mitigate forecast risk, preserve options to increase system capability in the future and due to lack of cost effective stand-alone resource or energy efficiency alternatives, the solution package #1 from Table 4 is recommended to address the transmission equipment EOL needs and accommodate the demand forecast for the Ottawa and the Peterborough to Quinte West areas over the long-term. Solution package #1 includes:

- Refurbish all 800 km of 230 kV circuits on the Gatineau Corridor identified as nearing EOL
- Build a new double circuit 230 kV transmission line into Dobbin TS (in Peterborough) from either Cherrywood TS (in Pickering) or Clarington TS (in Oshawa) with a planned in-service of 2029
- Pursue up to 230 MW of additional system cost-effective energy efficiency in the Ottawa area over the 20 year planning horizon, while monitoring demand growth and resource acquisition activities in the Ottawa zone
- Update and expand the use of remedial action schemes (RAS) in the Peterborough and Ottawa areas to meet planning standards and further improve both areas' LMCs

This solution package represents the lowest cost option, with transmission reinforcements estimated to cost approximately \$650 M. The transmission reinforcements ensure reliability in the Peterborough to Quinte West area is sufficient for the next 20 years and reliability in the Ottawa area is sufficient until 2037. If the 230 MW of additional energy efficiency is implemented, the Ottawa area's reliability would also be sufficient over the long-term. By refurbishing the existing Gatineau transmission lines and maintaining the supply capacity these lines provide Ottawa, this preserves the ability to further expand the LMC of Ottawa in the future with new transmission from Cornwall, when required. While there exists some load forecast uncertainties (high growth scenarios such as electrification of vehicles, heating, etc.) that, if materialized, can result in the need for additional improvements in the Ottawa area, this solution package lays the foundation to build on. Transmission planning in Ottawa will continue with the next cycle of regional planning scheduled to begin in Q4 2022.

Beyond monitoring load growth to trigger future system reinforcements when they are required, there are additional options with shorter lead times which could contribute to meeting Ottawa's supply capacity needs should they arise under a high growth scenario, including use of imports from Quebec, local demand response, BESS, and targeting additional energy efficiency in Ottawa.

Lastly, as presented in this report, the new transmission line into Dobbin TS can originate from either Cherrywood TS in Pickering or Clarington TS in Oshawa. While both routes are comparable in terms of addressing the needs for Peterborough to Quinte West and Ottawa, a new transmission line originating from Cherrywood TS may provide additional benefits for potential load connections in the Pickering and Whitby areas. Regional planning for the GTA East region is currently in-between planning cycles (in-active), however the working group members remain engaged in discussion to help inform the final line routing decision.

Appendix A – Planning Assessment Criteria

In developing this bulk plan, the IESO followed a number of steps including:

- Data gathering, including development of electricity demand forecasts;
- Conducting technical studies to determine electricity needs and the timing of these needs;
- Developing potential options; and
- Preparing a recommended plan including actions for the near and longer term.

Throughout this process, engagement was carried out with stakeholders interested in the area, in the form of public webinars and targeted discussions with the affected communities, local distribution companies and transmitters.

This bulk report documents the inputs, findings and recommendations developed through the process described above and provides recommended actions for the various entities responsible for plan implementation. The report helps ensure that recommendations to address near-term needs are implemented, while maintaining the flexibility to accommodate changing long-term conditions.

The overall objectives of planning are consistent among both regional and bulk planning, which are the following:

- Ensure reliability and service quality;
- Enable economic efficiency; and
- Support sector policy and decision making.

There are various reliability standards which, as the electricity system planner and operator, the IESO is obliged to meet. NERC and NPCC membership requires the bulk system be planned to consider specific operating conditions, such as peak and light load, and a set of contingencies to ensure the bulk system is planned reliably and meets standards. Additionally, the IESO is required to demonstrate its adherence to these standards through compliance reporting.

Reliability standards require the IESO to define its own performance criteria to meet under the conditions and contingencies specified. The Ontario Resource and Transmission Assessment Criteria (ORTAC) define the planning performance criteria for Ontario which are more specific and/or more stringent standards than NERC/NPCC. The IESO also considers operational issues and solutions that simultaneously consider bulk system reliability needs, regional needs, and assets reaching end of life, as appropriate.

The study used the planning criteria in accordance with events and performance as detailed by:

- NERC TPL-001 “Transmission System Planning Performance Requirements” (TPL-001),
- NPCC Regional Reliability Reference Directory #1 “Design and Operation of the Bulk Power System” (Directory #1), and
- IESO Ontario Resource and Transmission Assessment Criteria (ORTAC).

In addition to meeting established criteria and standards, the IESO also seeks to enable economic efficiency and support sector policy. Bulk system planning has a role in ensuring policy objectives can be incorporated with maximum benefit to ratepayers, and in identifying opportunities for improving overall system economics, especially in a competitive environment. This includes seeking economic opportunities, such as reducing losses, congestion, or other service costs, facilitate intertie/trade requirements, and providing timely and relevant information to market participants to enhance their participation and decision making leading to greater market efficiency and competition. It also includes supporting policy implementation affecting the power grid, such as sensitivity analysis of the economic impact of carbon pricing policies on congestion costs, as well as considering community energy plans and goals.

Appendix B – Load Forecast and Supply Need Data

The following datasets are included in this section and are also available in the excel file provided:

- Ottawa peak demand forecasts
 - Table 4 & 5: Total coincident reference and high growth scenarios for summer and winter seasons
- Peterborough to Quinte West peak demand forecasts
 - Table 6: Total coincident reference scenario for summer season

Refer to the excel file provided for the following datasets:

- Table 7: Forecast Ottawa Hourly Load (2022 to 2042)
- Table 8: Forecast Peterborough to Quinte West Hourly Load (2019 to 2037)
- Table 9: Forecast Ottawa Hourly Capacity Need (2022 to 2042)
- Table 10: Forecast Peterborough to Quinte West Hourly Capacity Need (2019 to 2037)

Notes:

The planning forecast for the Ottawa area is aligned with the Ottawa Zone demand forecast from the 2021 Annual Planning Outlook (Ottawa planning area aligns with definition of the Ottawa Zone)¹⁸

The planning forecast for the Peterborough to Quinte West area is aligned with the Peterborough to Kingston Integrated Regional Resource Plan demand forecast (Peterborough to Quinte West need is more local in nature comprising of a small number of stations)¹⁹

¹⁸ The 2021 Annual Planning Outlook is available on the IESO website ([link](#)).

¹⁹ The 2021 Peterborough to Kingston IRRP is available on the IESO website ([link](#)).

Table 5 | Total Coincident Winter Ottawa Peak Demand Forecast (MW)

Forecast Scenario	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Reference Scenario	1505	1529	1552	1575	1601	1618	1644	1668	1696	1714	1729	1760	1788	1824	1857	1892	1931	1969	2020	2076
High Growth Scenario	1,505	1,533	1,562	1,591	1,625	1,651	1,686	1,720	1,758	1,790	1,817	1,857	1,893	1,930	1,963	2,008	2,054	2,101	2,142	2,184

Table 6 | Total Coincident Summer Ottawa Peak Demand Forecast (MW)

Forecast Scenario	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Reference Scenario	1627	1650	1697	1722	1720	1713	1748	1788	1777	1828	1811	1824	1846	1905	1902	1961	1992	2027	2095	2170
High Growth Scenario	1,627	1,656	1,709	1,742	1,750	1,754	1,801	1,839	1,827	1,891	1,896	1,909	1,952	2,018	2,082	2,142	2,171	2,202	2,264	2,331

Table 7 | Total Coincident Summer Peterborough to Quinte West Peak Demand Forecast (MW)

Forecast Scenario	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reference Scenario	317	324	330	330	331	333	335	337	340	343	347	350	354	358	361	365	367	371



Appendix C – Assessment of Supply

The IESO assessed supply capacity requirements for Peterborough to Quinte West and Ottawa areas based on the details in the following sections.

Capacity Assessment

A deterministic approach was used to evaluate the need to improve the load meeting capability of the Peterborough to Quinte West and Ottawa areas. A need was identified where the annual coincident load forecast exceeded the total installed capacity of transmission-connected gas generation in winter or summer (discounted by seasonal derates) and the transmission interface transfer limits (FIDS and FIO).

For example, in the Ottawa supply capacity need is identified when the Ottawa demand is larger than the internal generation resources (70 MW, less derates and contract expiry) plus the transmission capacity into the Ottawa area (i.e., on the FIO interface).

The assessment considered the installed capacity of transmission-connected gas generation in winter or summer (discounted by seasonal derates). To be conservative, imports were not considered as part of this assessment (nor exports). The capability of hydro-electric generation is impacted by water levels which varies based on rainfall and snowmelt. The assessment considered the hydro-electric generation at output levels available during 98% of the time historically (i.e. dry conditions).

Appendix D – Economic Assessment Assumptions

The following is a list of the assumptions made in the economic analysis:

1. The NPV of the cash flows is expressed in 2021\$ CAD.
2. The USD/CAD exchange rate was assumed to be 0.76.
3. Natural gas price forecast is as per Sproule Outlook @ Dawn used in the 2021 Annual Planning Outlook (APO).
4. The NPV analysis was conducted using a 4% real social discount rate. Sensitivities at 6% and 8% were performed. An annual inflation rate of 2% is assumed.
5. The life of the station upgrades was assumed to be 45 years; the life of the line was assumed to be 70 years; and the life of the generators and BESS was assumed to be 30 years and 15 years respectively. The life of the BESS was based on 3600 cycles, which is assumed to be used to serve the local need first, and then global energy and ancillary services for the rest of the year. Cost of asset replacement were included where necessary to ensure the same NPV study period.
6. Development timelines for transmission was assumed to be 7 years; development timelines for generation and BESS were assumed to be 3 years.
7. A SCGT and CCGT were identified as one of the lowest-cost gas generation resource alternatives, based on escalating values from a previous study independently conducted for the IESO.²⁰ A sensitivity of +/- 25% was assessed.
8. A BESS was identified as one of the lowest-cost resource alternatives. Total energy storage system costs are composed of capacity and energy costs (i.e. energy storage devices are constrained by their energy reservoir). Costs were based on escalating values from the 2022 NREL Electricity Annual Technology Baseline (ATB)²¹. A sensitivity of +/- 25% was assessed.
9. Sizing of the storage solution was based on meeting the peak capacity and peak energy requirements for the local reliability need, such that the reservoir size is capable of using existing gas resources to sufficiently charge to meet the hours of unserved energy.
10. System capacity value was \$570/MW-day (2021\$ CAD) based on the estimated Net Cost of New Entry (Net CONE) of the anticipated lowest cost marginal resource that would be developed in Ontario when new generation is required. A sensitivity of +/- 25% assessed.
11. Production costs were determined based on energy requirements to serve the local reliability need, assuming the fixed and variable operating & maintenance costs for the resource.

²⁰ New natural gas-fired generation was considered in the economic analysis for illustrative purposes to represent the lowest option of new generation.

²¹ <https://data.openei.org/submissions/4129>

12. Carbon pricing assumptions are based on the Ontario Emissions Performance Standards (EPS) program, from \$50/t in 2022 to \$170/t by 2030, and applied to a new facility's production. A sensitivity of +100% was assessed.
13. The assessment was performed from an electricity consumer perspective and included all costs incurred by project developers, which were assumed to be passed on to consumers.
14. Planning estimates for the various transmission facilities assessed were constructed based on similar past projects with assistance from Hydro One. Transmission line refurbishment for a single circuit transmission line costs were assumed at \$500k/km and new transmission line costs were assumed at roughly \$3-4M/km.

Appendix E – Sizing Battery Energy Storage Systems

To determine the size requirements of BESS that could serve this local need, the dynamics of the need were investigated in detail to ensure that the potential BESS is able to sequentially charge/inject within the local limitations. The system was sized such that the reservoir would have enough storage capability to charge enough energy (MWh) overnight and inject it the next day, with enough capacity (MW) to shave the peak such that it never exceeds the transmission limit.

To accomplish this, a methodology was derived to size BESS for local needs. In general, the model inputs are the local load profile, local transmission limits to avoid, and local energy available for charging the BESS. These inputs are at the hourly granularity, and typically projected for many future years. The first step of the algorithm is to determine the largest peak power capacity requirement (i.e. the single hour where the local load is highest above the transmission limit) and the largest peak energy requirement (i.e. the largest amount of energy required to shave the biggest peak) for the year.

**Independent Electricity
System Operator**

1600-120 Adelaide Street West
1T1

Phone: 905.403.6900

Toll-free: 1.888.448.7777

E-mail: customer.relations@ieso.ca

ieso.ca



[@IESO_Tweets](https://twitter.com/IESO_Tweets)

linkedin.com/company/IESO

PETERBOROUGH TO KINGSTON RIP (MAY 2022)



Peterborough to Kingston

REGIONAL INFRASTRUCTURE PLAN

May 27, 2022



[This page is intentionally left blank]

Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Eastern Ontario Power Inc.
Elexicon Energy Inc. (Elexicon)
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Kingston Hydro
Lakefront Utilities Inc.



[This page is intentionally left blank]

DISCLAIMER

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

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

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

[This page is intentionally left blank]

EXECUTIVE SUMMARY

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

The participants of the RIP Technical Working Group (TWG) included members from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Eastern Ontario Power Inc.
- Elexicon Energy Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Kingston Hydro
- Lakefront Utilities Inc.

This RIP is the final phase of the second cycle of the Peterborough to Kingston regional planning process. It follows the completion of the Peterborough to Kingston Integrated Regional Resource Plan (“IRRP”) in November 2021 and the Peterborough to Kingston Needs Assessment (“NA”) in February 2020.

The Peterborough to Kingston RIP provides a consolidated summary of the needs and recommended plans for the region based on available information. It discusses the needs identified in the previous and current regional planning cycle, , any new needs identified as part of this RIP phase, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway from the previous planning cycle, including:

- Load transfer from Gardiner TS DESN 1 to Gardiner TS DESN 2 to provide transformation capacity relief at Gardiner TS DESN 1 (completed in 2019)

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

Table 1-1: Recommended Plans in Peterborough to Kingston over the Next 10 Years.

Stations/Lines Project	Details	In-Service Timeframe	Budgetary Cost Estimate ⁽¹⁾ (\$Million)
Cataraqui TS: Upgrade secondary conductor	Upgrade existing copper conductor on secondary side of auto transformers	2023	\$0.5
Gardiner TS DESN1: Station Capacity and Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard ²	2028*	\$30
	Load transfer from DESN1 to DESN2	2022	\$0.5
Frontenac TS: Station Capacity	Develop plan to build new 230kV 75/125 MVA DESN station in the area, as needed	2025-2029	\$30-\$35
Otonabee TS 44kV: Station Capacity	Transfer 8MW of load from Otonabee 44kV bus to Dobbin TS	2022	\$0.1
Port Hope TS: Transformers T3/T4 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2026	\$25
Belleville TS: Build new DESN	Build a new 230 kV 75/125 MVA DESN with associated capacitor banks at the existing Belleville TS site	2026	\$35-\$40
Picton TS: Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2025	\$14.5
Dobbin TS: T1/T2/T5 Auto Transformer Asset Renewal	Replace the end-of-life auto transformers with two new 150/250 MVA unit and switchyard refurbishment	2029	\$100

*Hydro One is exploring whether Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

The Study Team recommends that:

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

¹ Planning estimates are provided for Hydro One's portion of the work based on 2020 costs and are subject to change in the future

² The new standard units are expected to have a higher LTR of about 160 MW

TABLE OF CONTENTS

Disclaimer.....	5
Executive Summary.....	7
Table of Contents.....	9
List of Figures.....	11
List of Tables.....	11
1. Introduction.....	13
1.1. Objectives and Scope.....	14
1.1. Structure.....	14
2. Regional Planning Process.....	15
2.1 Overview.....	15
2.2 Regional Planning Process.....	15
2.3 RIP Methodology.....	18
3. Regional Characteristics.....	20
4. Transmission Facilities/projects Completed and/or underway over the Last Ten Years.....	22
5. Forecast And Other Study Assumptions.....	23
5.1 Load Forecast.....	23
5.2 Study Assumptions.....	24
6. Adequacy of existing Facilities.....	25
6.1 230/115 kV Autotransformers.....	25
6.2 230 kV Transmission Lines.....	26
6.3 115 kV Transmission Lines.....	26
6.4 230 kV and 115 kV Connection Facilities.....	27
6.4.1 Belleville TS T1/T2 Station Capacity Need.....	27
6.4.2 Frontenac TS T3/T4 Station Capacity Need.....	27
6.4.2 Gardiner TS DESN 1 (T1/T2) Station Capacity Need.....	28
6.4.3 Otonabee TS (T1/T2) 44kV Capacity Need.....	28
6.4.4 Other TSs and HVDSs in the Region.....	28
6.5 System Reliability and Load Restoration.....	29
6.6 Other Needs.....	30
6.6.1 Asset Renewal Needs for Major HV Transmission Equipment.....	30
7. Regional Plans.....	31
7.1 Supply Capacity – Peterborough to Quinte West.....	32
7.1.1 Description.....	32
7.1.2 Alternatives and Recommendation.....	32
7.2 Supply Capacity – Cataraqui TS Autotransformers.....	32
7.2.1 Description.....	32
7.2.2 Alternatives and Recommendation.....	32
7.3 Station Capacity – Belleville TS.....	32
7.3.1 Description.....	32
7.3.2 Alternatives and Recommendation.....	33
7.4 Station Capacity – Frontenac TS.....	34
7.4.1 Description.....	34
7.4.2 Alternatives and Recommendation.....	34
7.5 Station Capacity – Gardiner TS DESN 1 (T1/T2).....	35

7.5.1	Description	35
7.5.2	Alternatives and Recommendation	35
7.6	Station Capacity – Otonabee TS 44kV bus (T1/T2)	36
7.6.1	Description	36
7.6.2	Alternatives and Recommendation	36
7.6	Asset Renewal Need – Picton TS T1/T2 Transformer Replacement	37
7.6.1	Description	37
7.6.2	Alternatives and Recommendation	37
7.7	Asset Renewal Need – Port Hope TS T3/T4 Transformer	38
7.7.1	Description	38
7.7.2	Alternatives and Recommendation	38
7.8	Asset Renewal Need – Gardiner TS T1/T2 (DESN 1) Transformer	38
7.8.1	Description	38
7.8.2	Alternatives and Recommendation	39
7.9	Asset Renewal Need – Dobbin TS T1/T2/T5 Auto Transformers	39
7.9.1	Description	39
7.9.2	Alternatives and Recommendation	40
8.	Conclusion and Next Steps.....	41
9.	References	43
	Appendix A: Stations in the Peterborough to Kingston Region	44
	Appendix B: Transmission Lines in the Peterborough to Kingston Region	45
	Appendix C: Distributors in the Peterborough to Kingston Region	46
	Appendix D: Area Stations Load Forecast	47
	Appendix E: List of Acronyms	50

LIST OF FIGURES

Figure 1-1: Peterborough to Kingston Region	13
Figure 2-1: Regional Planning Process Flowchart.....	17
Figure 2-2: RIP Methodology	19
Figure 3-1: Single Line Diagram of Peterborough to Kingston's Transmission Network.....	21
Figure 5-1: Peterborough to Kingston Region Load Forecast	24

LIST OF TABLES

Table 1-1: Recommended Plans in Peterborough to Kingston over the Next 10 Years.....	8
Table 6-1: Step-Down Transformer Stations and High Voltage Distribution Stations	27
Table 6-2: Adequacy of the Step-Down Transformation Facilities	28
Table 6-3: Peterborough to Kingston Region – Planned Asset Replacement Work	30
Table 7-4: Identified Near and Mid-Term Needs in Peterborough to Kingston Region.....	31
Table 7-5: Major Asset Renewal Needs in Peterborough to Kingston Region.....	31
Table 8-1: Recommended Plans in Peterborough to Kingston Region over the Next 10 Years.....	42
Table D-1: Net Summer Coincidental Load Forecast (MW).....	47
Table D-2: Net Winter Coincidental Load Forecast (MW)	48
Table D-3: Net Summer Load Forecast for stations with capacity needs (MW)	48
Table D-4: Net Winter Load Forecast for stations with capacity needs (MW).....	49
Table D-5: Net Summer Non-Coincidental Load Forecast Growth Scenario 1 (MW)	49
Table D-6: Net Winter Non-Coincidental Load Forecast Growth Scenario 1 (MW).....	49
Table D-7: Net Winter Non-Coincidental Load Forecast Growth Scenario 2 (MW).....	49

[This page is intentionally left blank]

1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE PETERBOROUGH TO KINGSTON REGION.

The report was prepared by Hydro One Networks Inc. (“Hydro One”) on behalf of the Technical Working Group (TWG) that consists of Hydro One Inc. (Transmission), Eastern Ontario Power Inc., Elexicon Energy Inc. (“Elexicon”), Hydro One Inc. (Distribution), Independent Electricity System Operator (“IESO”), Kingston Hydro, and Lakefront Utilities Inc., in accordance with the Regional Planning process established by the Ontario Energy Board (“OEB”) in 2013.

The Peterborough to Kingston region is comprised of the area bordered approximately by Clarington on the West, North Frontenac county on the North, Frontenac County on the East and Lake Ontario on the South. The boundaries of the Region are shown in Figure 1-1 below.

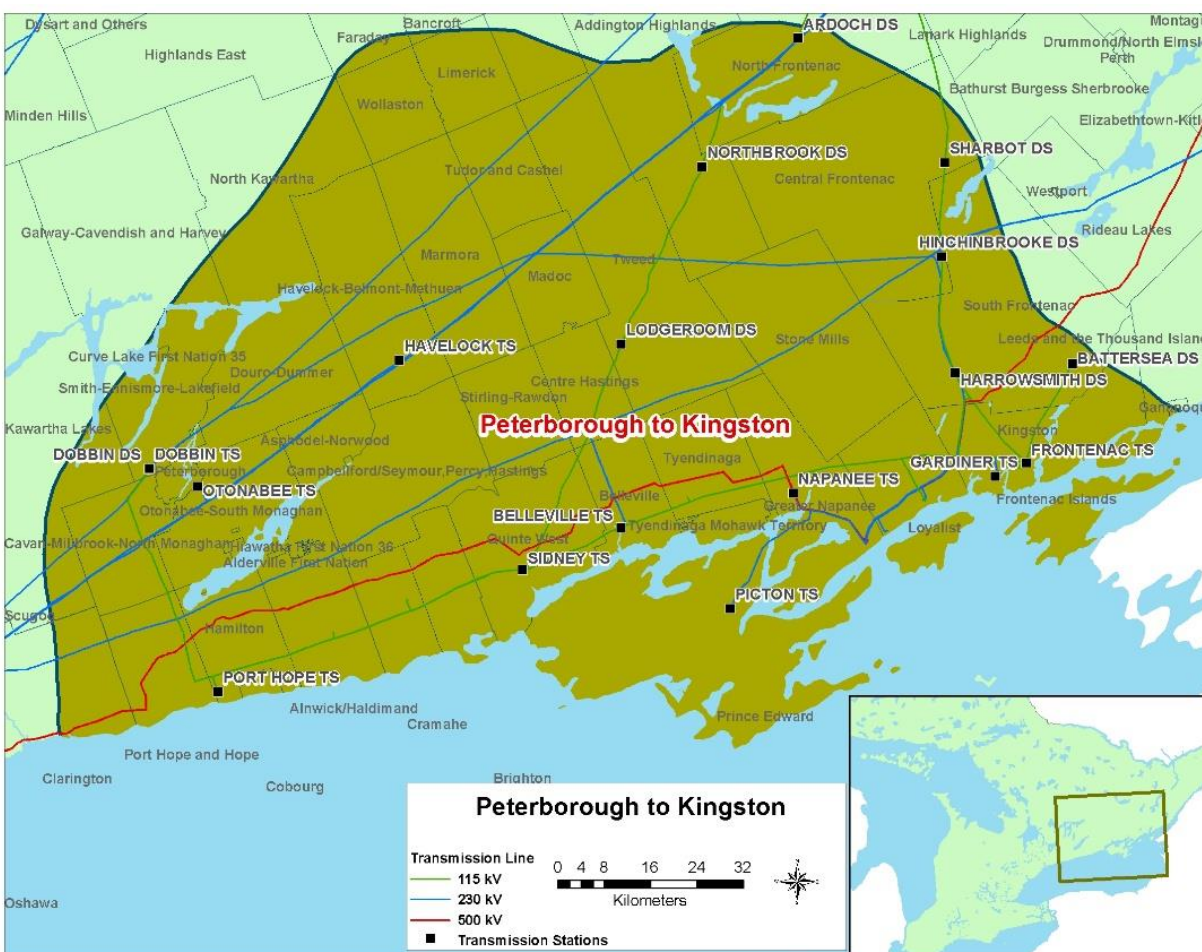


Figure 1-1: Peterborough to Kingston Region

1.1. Objectives and Scope

This RIP report examines the needs in the Peterborough to Kingston Region. Its objectives are to:

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan, and Integrated Regional Resource Plan).
- Identification of any new needs over the planning horizon and wires plans to address them
- Consideration of long-term needs identified in the Peterborough to Kingston IRRP or identified by the TWG.

1.1. Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board (“OEB”) in 2013 through amendments to the Transmission System Code (“TSC”) and Distribution System Code (“DSC”). The process consists of four phases: the Needs Assessment³ (“NA”), the Scoping Assessment (“SA”), the Integrated Regional Resource Plan (“IRRP”), and the Regional Infrastructure Plan (“RIP”).

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

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

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

³ Also referred to as Needs Screening

the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region.

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

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

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

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

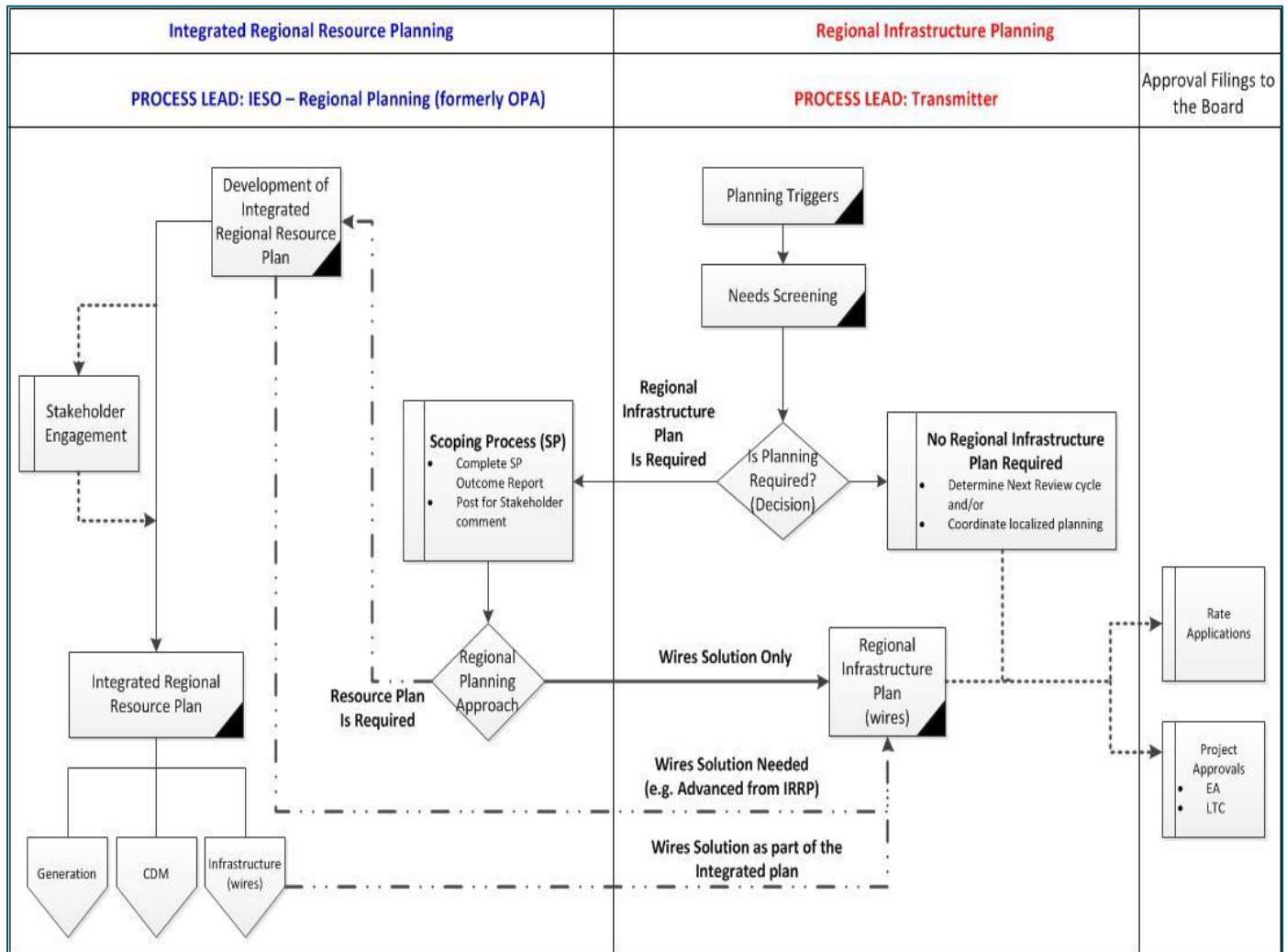


Figure 1: Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. **Data Gathering:** The first step of the RIP process is the review of planning assessment data collected in the previous phases of the regional planning process. Hydro One collects this information and reviews it with the TWG to reconfirm or update the information as required. The data collected includes:
 - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As agreed by TWG members, the load forecast from the IRRP was used for this RIP.
 - Existing area network and capabilities including any bulk system power flow assumptions.
 - Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.
2. **Technical Assessment:** The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon any changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to a specific issue(s) only. Additional needs may be identified in this phase.
3. **Alternative Development:** The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. **Implementation Plan:** The fourth and last step is the development of the implementation plan for the preferred alternative.

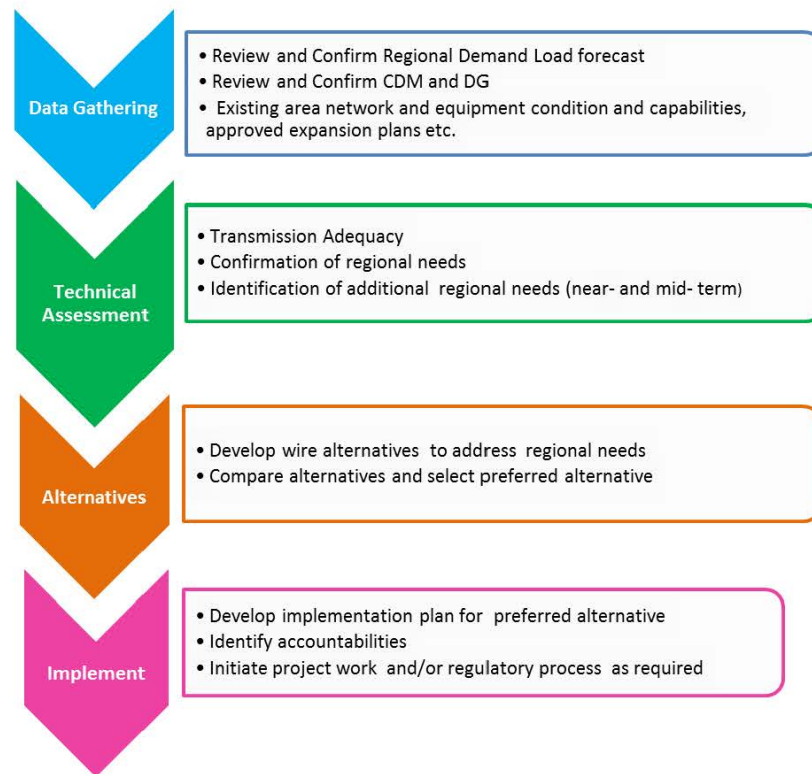


Figure 2-2: RIP Methodology

3. REGIONAL CHARACTERISTICS

THE PETERBOROUGH TO KINGSTON REGION IS COMPRISED OF THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY THE MUNICIPALITY OF CLARINGTON ON THE WEST, NORTH FRONTENAC COUNTY ON THE NORTH, FRONTENAC COUNTY ON THE EAST, AND LAKE ONTARIO ON THE SOUTH. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM TEN STEP-DOWN TRANSFORMER STATIONS AND EIGHT HIGH VOLTAGE DISTRIBUTION STATIONS.

Electrical supply to the region is provided through 500/230kV autotransformers at Lennox TS and 230/115kV autotransformers at Cataraqui TS and Dobbin TS, and a 230kV and 115kV transmission network supplying the various step-down TS's and HVDS's in the region. The main generation facility in the region is the 2000 MW Lennox Generation Station connected to Lennox TS.

The Local Distribution Customers (LDC) in the Peterborough to Kingston Region are Hydro One Distribution, Eastern Ontario Power, Elexicon, Kingston Hydro, and Lakefront Utilities. The high-voltage system in this Region also provides supply to five other direct transmission connected load customers.

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

- Lennox TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230 kV autotransformers.
- Cataraqui TS and Dobbin TS are the transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.
- Ten step-down transformer stations supply the Peterborough to Kingston load: Dobbin TS, Port Hope TS, Sidney TS, Picton TS, Otonabee TS, Havelock TS, Belleville TS, Napanee TS, Gardiner TS, and Frontenac TS. There are also eight HVDS that supply load in the Region: Dobbin DS, Ardoch DS, Northbrook DS, Lodgeroom DS, Hinchinbrooke DS, Harrowsmith DS, Sharbot DS, and Battersea DS
- Five Customer Transformer Stations (CTS) are supplied in the Region
- There are 7 existing Transmission connected generating stations in the Region as follows:
 - NPIF Kingston GS is a 130 MW gas-fired cogeneration facility that connects to 230 kV circuits X1H and X2H near Lennox TS
 - Lennox GS is a 2000 MW natural gas-fired station connected to Lennox TS
 - Wolfe Island GS is a 198 MW wind farm connected to circuit X4H near Gardiner TS
 - Napanee GS is a 910 MW gas-fired plant connected to Lennox TS at the 500 kV system

-

Figure 3-1: Single Line Diagram of Peterborough to Kingston's Transmission Network

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

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

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

- Connect Napanee GS (2017) – A 910 MW gas turbine (Napanee GS) was connected to the 500 kV bus in the Lennox TS switchyard
- Transformation capacity relief at Gardiner TS DESN 1 (2019) – Gardiner TS DESN 1 load exceeded its normal supply capacity. Hydro One Distribution transferred load from Gardiner TS DESN 1 to Gardiner TS DESN 2.

The following projects are currently underway:

- Lennox TS 230kV & 500kV Breaker Replacement (2026/27)
- Belleville TS T1/T2 Transformer Replacement (2022)

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The electricity demand in the Peterborough to Kingston Region is anticipated to grow about .8% annually from 2021 to 2031.

Figure 5-1 shows the Peterborough to Kingston Region’s extreme weather coincident peak net load forecast (“load forecast”) for summer and winter. The load forecast for the individual stations in the Peterborough to Kingston Region is given in Appendix D.

As per the new regional planning process requirement, the load forecast used in the RIP is same as the IRRP phase unless there is a material change or if a LDC(s) member of the TWG requests to update their load forecast.

In the case of the Peterborough to Kingston Region, the TWG decided to use the load forecast in the recently completed Peterborough to Kingston Region IRRP (Nov. 2021) for the purposes of the RIP load forecast. Note that the TWG reviewed the extreme summer non-coincident peak net load forecast from the IRRP against the actual historical peak load observed in 2020 for the stations that have been identified to have a capacity need, namely Belleville TS, Frontenac TS, Gardiner TS DESN 1, and Otonabee TS (discussed in Section 6.4). Although, the actual 2020 peak load for these stations is slightly lower than what was forecasted in the IRRP, the TWG decided to proceed with the IRRP 2020 forecasted load since it does not materially change the planning outcome. The need dates will continue to be monitored throughout the regional planning process.

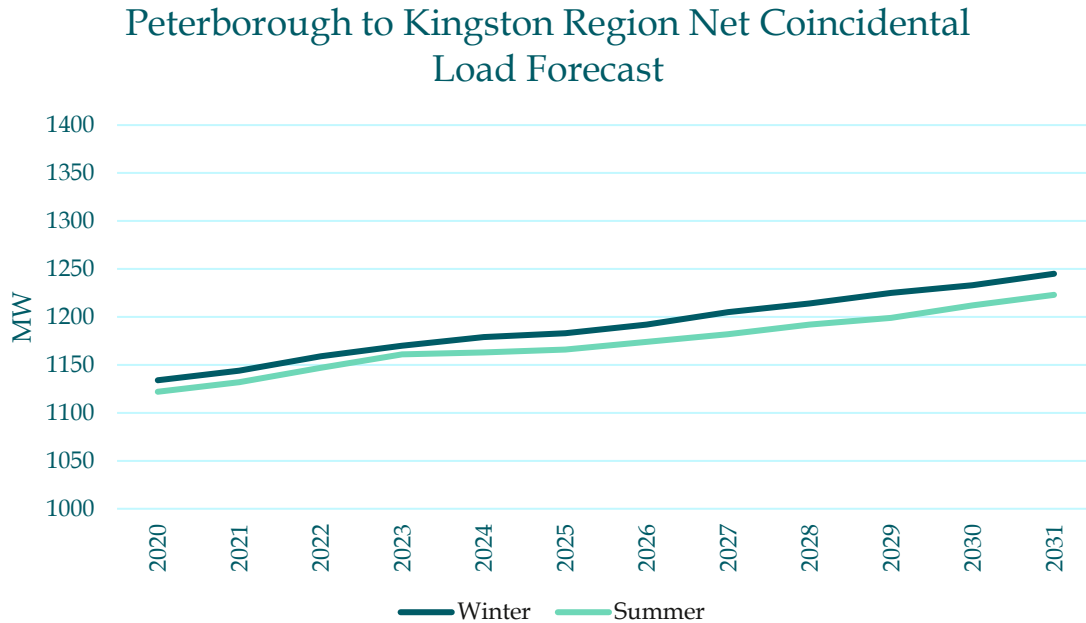


Figure 5-1: Peterborough to Kingston Region Load Forecast

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP adequacy assessment is 2020-2031.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for all stations for stations having no low voltage capacitor banks and .95% lagging power factor for stations having low voltage capacitor banks
- Normal planning supply capacity for transformer stations is determined by the summer 10-Day Limited Time Rating (LTR).
- Line capacity adequacy is assessed using peak loads in the area.
- Output of generating stations in the area is based on 98% dependable generation availability for transmission connected run of river hydro-electric stations as per Ontario Resource Transmission Assessment Criteria (ORTAC) criteria.
- Adequacy assessment is conducted as per ORTAC and using the load forecast described in section 5.1.

6. ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND TRANSFORMER STATION FACILITIES SUPPLYING THE PETERBOROUGH TO KINGSTON REGION OVER THE PLANNING PERIOD (2021-2031).

Within the current regional planning cycle, three regional planning reports have been completed for the Peterborough to Kingston Region. The findings of these reports are inputs to this Regional Infrastructure Plan. These reports are:

- 2020 Peterborough to Kingston Region Needs Assessment (“NA”) Report;
- 2020 Peterborough to Kingston Region Scoping Assessment (“SA”) Report; and,
- 2021 Peterborough to Kingston Region Integrated Regional Resource Plan (“IRRP”)

This section provides a review of the adequacy of the transmission lines and stations in the Peterborough to Kingston Region. The adequacy is assessed using the latest regional load forecast provided in Appendix D and assumes all projects currently underway (described in section 4) are in-service. Sections 6.1 to 6.5 present the results of this review. Asset renewal needs for major HV transmission equipment were identified in previous phases of this regional planning cycle and are also addressed in Section 7 of this RIP report.

6.1 230/115 kV Autotransformers

Bulk power supply to the Peterborough to Kingston Region is provided by Hydro One’s 500kV/230kV and 230 kV/115kV autotransformers. The number and location of these autotransformers are as follows:

- a) Two 500/230 kV autotransformers at Lennox TS
- b) Two 230/115 kV autotransformers at Cataraqui TS
- c) Three 230/115 kV autotransformers at Dobbin TS

The 500/230 kV autotransformers at Lennox TS are part of the bulk system and outside the scope of this RIP.

Based on the RIP load forecast, the load growth at Frontenac TS and other 115kV supply stations is expected to result in a supply capacity need at Cataraqui TS in 2023. The load is expected to increase over the long-term.

The 230/115 kV autotransformers at Dobbin TS are expected to be adequate over the study period.

6.2 230 kV Transmission Lines

All 230 kV transmission circuits, with the exception of circuits X21 and X22 in the Peterborough to Kingston Region are classified as part of the Bulk Electricity System (“BES”). They connect the Region to the rest of the Ontario’s transmission system and to the load centers in the Greater Ottawa regions. These circuits are as follows:

- 230kV circuits: C27P, H23B, H27H, P15C, T22C, T25B, T31H, T32H, X1H, X1P, X2H, X3H and X4H.

These 230kV transmission lines can be divided into the main corridors as summarized below:

- a) Clarington TS to Otonabee TS, Havelock TS, Chats Falls SS 230kV circuits T22C, T31H, T32H
 - Supplies Otonabee TS, Havelock TS
- b) Clarington TS to Hinchinbrooke SS 230kV circuits T25B and H23B
 - Supplies Belleville TS
- c) Lennox TS to Hinchinbrooke SS 230 kV circuits, X1H, X2H, X3H, X4H
 - Supplies Gardiner TS and a Customer CTS
- d) Cherrywood TS to Dobbin TS, Chat Falls SS 230kV circuits P15C and C27P

From the circuits listed above, P15C is the limiting circuit for supply capacity needs in the region during low water conditions with a contingency on circuits X1P or C27P. This supply capacity need is being assessed as part of the bulk system planning.

6.3 115 kV Transmission Lines

The Peterborough to Kingston Region consists of several 115 kV lines. This 115 kV network serves local area load. The 115 kV transmission facilities can be divided into the main corridors as summarized below:

- a) Dobbin TS to Sidney TS 115kV transmission circuits P3S/P4S
 - Supplies Port Hope TS, Sidney TS, and two Customer CTS
- b) Sidney TS to Cataraqui TS 115kV transmission circuit Q6S
 - Supplies Sidney TS and a Customer CTS
- c) Cataraqui TS to Frontenac TS 115kV transmission circuits Q3K/B5QK
 - Supplies Sharbot DS, Hinchinbrooke DS, Harrowsmith DS, and Frontenac TS
- d) Barrett Chute GS to Sidney TS 115kV transmission circuit B1S
 - Supplies Ardoch DS, Northbrook DS, Lodgeroom DS

From the circuits listed above, Q6S is the limiting circuit for supply capacity needs in the region during low water conditions with a contingency on circuits 230kV circuits X1P, C27P, or P15C.

This supply capacity need is being assessed as part of the bulk system. The remaining 115 kV circuits are within their thermal limits and within the voltage range as per ORTAC for the loss of a single 115 kV circuit in the Region.

6.4 230 kV and 115 kV Connection Facilities

There is a total of ten step-down transformer stations and eight high voltage distribution stations that supply the Peterborough to Kingston load as shown in Table 6-1 below:

Table 6-1: Step-Down Transformer Stations and High Voltage Distribution Stations

Dobbin TS	Port Hope TS	Sidney TS	Picton TS
Otonabee TS	Havelock TS	Belleville TS	Napanee TS
Gardiner TS	Frontenac TS	Dobbin DS	Ardoch DS
Northbrook DS	Lodgeroom DS	Hinchinbrooke DS	Harrowsmith DS
Sharbot DS	Battersea DS		

A station capacity assessment was performed over the study period for the above stations in the Region using either the summer or winter station peak load forecasts as appropriate. The results are as follows:

6.4.1 Belleville TS T1/T2 Station Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Belleville TS was forecasted to be 170 MW⁴. The Summer 10-Day LTR of Belleville TS is about 161 MW.

Based on the RIP load forecast, Belleville TS is exceeding its Summer 10-Day LTR today and the magnitude of the need increases in the near and mid-term. In addition to normal load growth in the area, Elexicon has recently received approximately 30 MW of new load connection inquiries to be connected at Belleville TS.

6.4.2 Frontenac TS T3/T4 Station Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Frontenac TS is 101 MW⁵. The Summer 10-Day LTR of Frontenac TS is about 111 MW.

Based on the RIP load forecast, Frontenac TS is expected to reach its Summer 10-Day LTR by 2029.

⁴ The 2020 extreme summer weather non-coincident peak net load at Belleville TS is based on the 2021 Peterborough to Kingston Region IRRP load forecast, which has been adopted by the TWG for use in this RIP. The actual, weather corrected 2020 summer peak load at Belleville TS was 157 MW, but still forecasted to exceed the 161MW LTR in 2022.

⁵ The 2020 extreme summer weather non-coincident peak net load at Frontenac TS is based on the 2021 Peterborough to Kingston Region IRRP load forecast, which has been adopted by the TWG for use in this RIP. The actual 2020 summer peak load at Frontenac TS was 104 MW.

6.4.2 Gardiner TS DESN 1 (T1/T2) Station Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Gardiner TS DESN 1 was forecasted to be 146 MW⁶. The Summer 10-Day LTR of Gardiner TS DESN 1 and DESN 2 is about 125 MW and 85 MW, respectively.

Based on the RIP load forecast, the loading on Gardiner TS DESN 1 is exceeding its Summer 10-Day LTR today and the magnitude of the need increases in the near and mid-term.

6.4.3 Otonabee TS (T1/T2) 44kV Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Otonabee TS 44 kV bus was 103 MW . The Summer 10-Day LTR of Otonabee TS 44kV is 97 MW.

Based on the 2020 net loading and load forecast, the loading on Otonabee TS 44kV is exceeding its Summer 10-Day LTR today and the magnitude of the need increases in the near and mid-term.

6.4.4 Other TSs and HVDSs in the Region

Based on the RIP load forecast, all the other TSs and HVDSs in the Region are expected to be within their normal supply capacity during the study period. Therefore, any capacity needs for these TSs and HVDSs will be reviewed in the next regional planning cycle.

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

Station	Summer 10-Day LTR Capacity (MW)	2020 Summer Peak Net Forecast (MW)	Need Date
Belleville TS T1/T2	161	170	Today
Frontenac TS T3/T4	111	101	2029
Gardiner TS DESN 1 (T1/T2)	125	146	Today
Otonabee TS 44kV Bus	97	103	Today

⁶ The 2020 extreme summer weather non-coincident peak net load at Gardiner TS DESN 1 is based on the 2021 Peterborough to Kingston Region IRRP load forecast, which has been adopted by the TWG for use in this RIP. The actual 2020 summer peak load at Gardner TS DESN 1 was 130 MW.

6.5 System Reliability and Load Restoration

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

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

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

6.6 Other Needs

6.6.1 Asset Renewal Needs for Major HV Transmission Equipment

Hydro One has identified asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Peterborough to Kingston Region. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

These needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Asset replacement work planned over the study period in the region is summarized in Table 6-3.

Table 6-3: Peterborough to Kingston Region – Planned Asset Replacement Work

No.	Station	Description	in-service Timing
1	Picton TS	T1/T2 Replacement	2025
2	Port Hope TS	T3/T4 Replacement	2026
3	Lennox TS	230kV & 500kV Breaker Replacement. Part of Bulk system	2026/27
4	Dobbin TS	Auto Transformers T1/T2/T5 Replacement	2029
5	Gardiner TS DESN 1	T1/T2 Replacement	2028*

*Hydro One is exploring whether Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

7. REGIONAL PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE PETERBOROUGH TO KINGSTON REGION AND PRESENTS WIRES ALTERNATIVES AND PREFERRED WIRES SOLUTIONS FOR ADDRESSING THESE NEEDS. TABLE 7-1 LISTS NEEDS PREVIOUSLY IDENTIFIED IN THE NA AND IRRP FOR THE PETERBOROUGH TO KINGSTON REGION AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THIS RIP REPORT.

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

Table 7-4: Identified Near and Mid-Term Needs in Peterborough to Kingston Region

Need Type	Section	Station/Circuit/Area	In-service Timing
Supply Capacity	7.1	Peterborough to Quinte West	Today
	7.2	Cataraqui TS Autotransformers	2023
Station Capacity	7.3	Belleville TS	Today
	7.4	Frontenac TS	2029
Station Capacity	7.5	Gardiner TS DESN 1 (T1/T2)	Today
Station Capacity	7.6	Otonabee TS 44kV Bus	Today

Table 7-5: Major Asset Renewal Needs in Peterborough to Kingston Region

Need Type	Section	Station/Circuit/Area	In-Service Timing
Asset Renewal for Major HV Transmission Equipment	7.7	Picton TS T1/T2 transformers	2025
	7.8	Port Hope TS T3/T4 transformers	2025
	7.9	Gardiner TS T1/T2 (DESN 1) transformers	2028*
	7.10	Dobbin Auto Transformers T1/T2/T5	2029

*Hydro One is exploring if and how Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

Maintaining status quo is not an option for any of the end of life autotransformers or station transformers due to risk of equipment failure and would result in increased maintenance cost and prolonged customer outages and interruptions. These transformers will be replaced with standard units.

No other lines or HV station equipment in the Peterborough to Kingston region than listed above, have been identified for major replacement/refurbishment at this time.

7.1 Supply Capacity – Peterborough to Quinte West

7.1.1 Description

The Peterborough to Quinte West sub region mainly consists of Port Hope TS and Sidney TS. The area is supplied from Dobbin TS to the North West, Cataraqui TS from the East, and Barrett Chute SS to the North East. During low water conditions and contingency situations, the thermal capacity on circuits P15C and Q6S can be exceeded.

7.1.2 Alternatives and Recommendation

IESO is currently undertaking a bulk study of the area and the recommendations from the study is expected to resolve the thermal loading limits of P15C and Q6S.

7.2 Supply Capacity – Cataraqui TS Autotransformers

7.2.1 Description

Cataraqui TS supplies the 115kV stations in the Eastern sub region of the region through two 230/115kV auto transformers. It is forecasted that in 2023 the coincidental loading of the stations in the sub region will reach the supply capacity of the Cataraqui TS auto transformers.

7.2.2 Alternatives and Recommendation

The current limitation of the Cataraqui TS auto transformers are due to a short span of copper conductors connected the secondary side of the auto transformers within the station. Upgrading the conductors will allow the long term emergency to increase by 35 MW and resolve this need in the near term.

7.3 Station Capacity – Belleville TS

7.3.1 Description

Belleville TS consists of one DESN supplied by 230kV circuits, H23B and T25B. The station has a summer 10-Day LTR of 161 MW. The station is also limited by voltage drop limitations when transmission circuit H23B is lost along with the companion transformer by configuration and the maximum loading can be as low as 130 MW, depending on the load composition at the station.

Based on the 2020 net load forecast, the station will exceed its capacity in 2022. In addition, Elexicon has also recently received approximately 30 MW of load connection inquiries to be connected at Belleville TS, but not including in the current load forecast. Hence, there is an immediate need for additional transformation capacity at Belleville TS today.

While the Belleville TS T1/T2 transformer replacement is currently underway, with an expected in-service date of 2022, this refurbishment is not expected to result in any significant improvement to the station's capacity and does not solve the voltage limitation issue.

7.3.2 Alternatives and Recommendation

The following alternatives were considered to address the Belleville TS station capacity need:

1. **Alternative 1 – Install a new DESN with two 75/125 MVA transformers with two 32 MVAR Capacitor banks and assess transmission line capacity:** Installing a second DESN at Belleville TS with two 32 MVAR capacitor banks will help mitigate the voltage drop at the Belleville TS LV bus and will resolve the station capacity need over the long-term (20 years) based on the current load forecast. Belleville TS switchyard also has space for a second DESN. The estimated cost for this option is approximately \$35-40 M. However, it should be noted that preliminary studies indicate that there will be voltage constraints on the transmission lines supplying Belleville TS for a H23B contingency, which will restrict the full utilization of the additional station capacity in the long term as the total load at Belleville TS DESN1 and the new Belleville TS DESN2 is expected to be limited to 210 MW total, but should be sufficient capacity to meet the forecasted demand in the next 20 years. To fully utilize the capacity of the second DESN and increase the capacity beyond 210 MW, new supply lines into Belleville will be required to alleviate the voltage drop limits at Belleville TS. A possible reinforcement option is to extend X21/X22 from Napanee TS to Belleville TS along an existing Q6S Right of Way. There may also be upstream bulk system impacts with this option, therefore a full bulk planning study is needed to identify any impacts when looking beyond 20 years.
2. **Alternative 2 – Install an additional third 75/125 MVA transformer at Belleville TS and assess transmission line capacity:** Installing a third transformer at Belleville TS would resolve the need over the study period, however it is not a long term solution as compared to alternative 1 as it does not provide reliability of a full DESN, will significantly increase short circuit level at the 44kV bus, and does not alleviate the current voltage limitation. The estimated cost for this option is also similar to alternative 1 at approximately \$30-35 M.
3. **Alternative 3 – Load transfers:** Since Belleville TS does not currently have any distribution load transfer capability, due to a lack of adjacent stations, distribution load transfers was not recommended by the TWG.

Considering the above alternatives, the TWG recommends Alternative 1. To address today's station capacity need at Belleville TS, as well as the growing electricity demand in the region,

Hydro One (Transmission and Distribution) and Elexicon have started development of a new DESN transformer station at Belleville, with an expected in-service date of 2026. This will increase the supply capacity to the region and will resolve the capacity need at Belleville TS in the near and mid term.

The TWG will continue to monitor the load growth at Belleville TS and revisit the capacity need in the next regional planning cycle in order to re-assess whether/when a transmission line reinforcement to Belleville is required in the long term. In case of a H25B contingency where voltage violations are exceeded, operational measures will be taken to resolve the issue. Furthermore, IESO will undertake any necessary bulk system studies regarding the transmission reinforcement to Belleville TS.

7.4 Station Capacity – Frontenac TS

7.4.1 Description

Frontenac TS consists of one DESN supplied by 115kV circuits, Q3K and B5QK. The Summer 10-Day LTR of Frontenac TS is about 111 MW.

Based on the 2020 net load forecast, Frontenac TS is expected to exceed its Summer 10-Day LTR by 2029 but can be as early as 2022 for a high growth scenario. As there is limited load transfer capability between Frontenac TS and Gardiner TS DESN1 and excess load in Eastern Kingston area may not be able to supply from Gardiner TS DESN1, there is a need for additional transformation capacity at Frontenac TS in the mid-term.

7.4.2 Alternatives and Recommendation

The following alternatives were considered to address the Frontenac TS station capacity need:

1. **Alternative 1 – Upgrade Frontenac T3/T4 transformers:** The transformers at Frontenac TS are already the largest size for a 115/44kV DESN and therefore upgrading these transformers is not feasible.
2. **Alternative 2 – Install a new DESN with 50/83MVA transformers at Frontenac TS:** As the 115kV circuits supplying Frontenac TS have little thermal capacity, adding a second DESN at Frontenac TS will require significant upgrades to the existing 115kV transmission circuits. In addition, the cost of converting 115 kV transmission line to 230 kV is large and has been a deterrent due to low load growth in the area.
3. **Alternative 3 – Extend 230kV circuits X2H and X4H 13 km to the East of St. Lawrence River and install a new 75/125 MVA DESN**
This option was assessed and reject due to the high cost and many environmental and real estate issues with the line extension.

4. **Alternative 4 –Build a new 230kV 75/125 MVA DESN near Gardiner TS**

Load transfer capability exists between Frontenac TS and Gardiner TS DESN 1 via 44kV feeder ties but is limited and for operation measures and is not be suitable for permanent new loads forecasted in Eastern Kingston. Building a new 230 kV DESN near the current X2H/X4H corridor can alleviate this constraint by supplying new load in the area as well as providing an extra station where load can be transferred from Frontenac TS to the new DESN, as needed.

Considering the above alternatives, the TWG recommends Alternative 4. Hydro One transmission will work with Kingston Hydro and Hydro One Distribution to undertake development work for a new station in the area in the near term, which may be built by the Transmitter or the LDC.

The development of additional energy efficiency, could defer the new station ultimately required to accommodate load growth in the City of Kingston. This is cost-effective, under the reference load growth scenario, if cost-allocation can reflect the system benefits the non-wires alternative would provide. Additional barriers to implementation also exist around who would implement the solution and how they would seek cost-recovery, particularly if the transmitter or both benefiting LDCs were to implement a part of the solution. The IESO will work with the impacted transmitter and LDCs between regional planning cycles to address these barriers to implementation and cost allocation for a non-wires alternative, in tandem with developing plans for a new transformer station

7.5 Station Capacity – Gardiner TS DESN 1 (T1/T2)

7.5.1 Description

Gardiner TS DESN 1 is supplied by 230 kV circuits X2H and X4H. The Summer 10-Day LTR of Gardiner TS DESN1 is 125 MW.

Based on the 2020 net load forecast, Gardiner TS has exceeded its Summer 10-Day LTR. Hence, there is a need for additional transformation capacity at Gardiner TS DESN1 in the near term.

7.5.2 Alternatives and Recommendation

The following alternatives were considered to address the Gardiner TS DESN1 station capacity need:

1. Alternative 1 – Expedite Gardiner TS DESN1 refurbishment:

As the current transformers 10 Day LTR is 125 MW, replacing it with new standard 75/125 MVA transformers will increase the LTR to about 160 MW. This will provide enough capacity to meet the load growth at DESN 1 until 2033.

2. Alternative 2 – Load Transfer from Gardiner TS DESN1 to Gardiner TS DESN2:

Gardiner TS DESN2 was built within the last 15 years and has a 10 day LTR of 85 MW. DESN2 has available capacity at the station to supply additional loading. Hydro One distribution has confirmed that an permanent additional 11 MW load transfer from Gardiner TS DESN1 to Gardiner TS DESN2 is possible by reconfiguring its distribution system.

Considering the above alternatives the TWG recommends to proceed with both Alternatives 1 and 2. As the cost of the distribution load transfer is low and the load transfer work is much faster than the Gardiner TS DESN1 refurbishment, Hydro One Distribution can proceed with the work to alleviate the immediate loading constraint on Gardiner TS DESN1 with an expected completion date end of 2022, while Hydro One Transmission will explore opportunity to accelerate the Gardiner TS DESN1 refurbishment. The combination of these two options will address the current capacity limit at Gardiner TS DESN1. Hydro One Transmission will provide an update to the Technical Working Group for Gardiner TS DESN1 refurbishment in Q3 2022.

7.6 Station Capacity – Otonabee TS 44kV bus (T1/T2)

7.6.1 Description

The 2020 non-coincident peak net load at Otonabee TS 44 kV bus was 103 MW . The Summer 10-Day LTR of Otonabee TS 44kV winding is 97 MW.

Based on the 2020 net load forecast, the loading on Otonabee TS 44kV is exceeding its Summer 10-Day LTR today. Hence, there is a need for additional transformation capacity at Otonabee TS 44 kV bus in the near term.

7.6.2 Alternatives and Recommendation

The following alternatives were considered to address the Otonabee TS 44kV station capacity need:

1. Alternative 1 – Transfer load from Otonabee TS 44kV to Dobbin TS:

Dobbin TS is nearby station that have over 50MW of remaining capacity and is not expected to reach its LTR of 160 MW in the long term. The secondary voltage is also 44kV, which allows load transfer between the two stations. Although there is an existing plan to transfer 4 MW of load from Otonabee TS 44kV bus to Dobbin TS, that is not enough to alleviate the capacity limits at Otonabee TS 44kV bus. Hydro One Distribution has confirmed that an additional 8 MW of load can be transfer from

Otonabee TS 44kV to Dobbin TS. This will provide enough capacity to meet the load growth forecast at Otonabee TS 44 kV bus until 2030.

2. Alternative 2 – Transfer load from Otonabee TS 44kV to Otonabee 27.5kV:

As the voltage levels are different between the 2 low voltage winding of the bus, transferring the load between the different voltages is extremely difficult, costly, and time consuming as it requires all the downstream DS's to be converted to 27.6kV, and in many cases due to distance is not feasible.

The TWG recommends that Hydro One Distribution proceed with the above work in Alternative 1 to ensure continued supply reliability to customers at Otonabee TS 44 kV. Otonabee TS 44kV bus will be monitored after the load transfer and plans should be made if more load transfer from Otonabee TS 44kV bus to Dobbin TS is needed in the long term.

7.6 Asset Renewal Need – Picton TS T1/T2 Transformer Replacement

7.6.1 Description

Picton TS is a 230/44kV transformer station serving Hydro One Distribution. The station comprises two 50/83MVA transformers, T1/T2. The station's 2020 actual peak load was 59 MW and it has a Summer 10-Day LTR of approximately 78MW.

Transformers T1 and T2 are currently about 60 years old and are planned for similar standard units based on their asset condition assessment and taking "right sizing" into consideration. The tentative in-service date is expected in 2025.

The TWG recommends that Hydro One proceed with the above work to ensure continued supply reliability to customers.

7.6.2 Alternatives and Recommendation

1. Alternative 1 - Maintain Status Quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. Alternative 2 - Like-for-like replacement with similar equipment: Proceed with these end of life asset replacement as per the existing refurbishment plan for the transformers at Picton TS T1/T2. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.7 Asset Renewal Need – Port Hope TS T3/T4 Transformer

7.7.1 Description

Port Hope TS is located in the city of Port Hope, Ontario and supplies Hydro One Distribution and Elexicon loads. Port Hope TS T3/T4 are 50/83 MVA transformers with a 10 day LTR of 104 MW. T3/T4 currently supplies about 70 MW of load and the long term forecast is well within the current LTR.

The T3/T4 transformers were built in 1959 and have been identified as has reached the end of service life and requiring replacement. The scope of this project is to replace T3/T4 step-down transformers, associated spill containment structure and majority of assets within 44 kV BY switchyard. The targeted in-service is in year 2025.

The Study Team has assessed right sizing approach to downsizing and/or upsizing these transformers based on needs. The Working Group concluded that reducing the size of these transformers is not an option as the load in the area is not decreasing. Upsizing is also not an option as the long term forecast does not justify upgrade. Accordingly, it is recommended to replace these transformers with similar size.

7.7.2 Alternatives and Recommendation

1. Alternative 1 - Maintain Status Quo:

This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. Alternative 2 - Like-for-like replacement with similar equipment:

Proceed with these end of life asset replacement as per the existing refurbishment plan for the transformers at Port Hope TS T3/T4. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.8 Asset Renewal Need – Gardiner TS T1/T2 (DESN 1) Transformer

7.8.1 Description

Gardiner TS is located in the city of Kingston, Ontario and supplies Hydro One Distribution and Kingston Hydro loads. Gardiner TS DESN1 T1/T2 are 75/125 MVA transformers with a 10 day LTR of 125 MW. The current loading on T1/T2 have exceeded its 10 day LTR.

The T1/T2 transformers were built in mid 1970s and has reached the end of service life requiring replacement in the previous planning cycle. Following recent inspections of the transformers, the conditions of the transformers were found to be acceptable and the plan to replace the transformers were deferred to 2028.

The Study Team has assessed downsizing and/or upsizing need for these transformers. As the 10 day LTR of the current transformers are substandard, the Working Group concluded that replacing the current transformers with new standard 75/125 MVA units will increase the supply capacity to about 160 MW and alleviate the current overloading at DESN1. Reducing the size of these transformers is not an option as the load in the area is increasing. Upsizing is also not an option as the current units are already the largest size for a 230/44kV step-down transformers.

7.8.2 Alternatives and Recommendation

1. Alternative 1 - Maintain Status Quo:

This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. Alternative 2 - Like-for-like replacement with similar equipment:

Expedite this end of life asset replacement as the current transformers are already overloaded. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.9 Asset Renewal Need – Dobbin TS T1/T2/T5 Auto Transformers

7.9.1 Description

Dobbin TS is located near the city of Peterborough, Ontario and supplies Peterborough to Quinte loads. Dobbin TS consists of three 230/115 kV auto transformers. T1 is rated at 150/250 MVA and T5 is rated at 115 MVA. T2 is rated at 36/78 MVA and currently out of service.

During the previous planning cycle, T2 and T5 were planned to be replaced with one 150/250 MVA unit. However, as T1 has also reached the end of service life, it would be more efficient and cost effective to replace all three transformers with two 150/250 MVA units.

7.9.2 Alternatives and Recommendation

1. Alternative 1 - Maintain Status Quo:

This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. Alternative 2 – Replace three existing autotransformers with two units:

Proceed with these end of life asset replacement as per the existing refurbishment plan for the transformers at Dobbin TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE PETERBOROUGH TO KINGSTON REGION.

This RIP report addresses near term and mid-term regional needs identified in the earlier phases of the Regional Planning process and during the RIP phase. The major infrastructure investments recommended by the TWG in the near and mid-term planning horizon are provided in Table 8-1 below. As the industry is currently witnessing supply chain issues and delays in procurement of equipments, it can impact the near term planning horizon if left unresolved.

Investments to address the mid-term needs, for cases where there is time to make a decision, will be reviewed and finalized in the next regional planning cycle. These needs are summarized in Table 8-1.

Table 8-1: Recommended Plans in Peterborough to Kingston Region over the Next 10 Years.

Stations/Lines Project	Details	In-Service Timeframe	Budgetary Cost Estimate ⁽⁷⁾ (\$Million)
Cataraqui TS: Upgrade secondary conductor	Upgrade existing copper conductor on secondary side of auto transformers	2023	\$0.5
Gardiner TS DESN1: Station Capacity and Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard ⁸	2028*	\$30
	Load transfer from DESN1 to DESN2	2022	\$0.5
Frontenac TS: Station Capacity	Develop plan to build new 230kV 75/125 MVA DESN station in the area, as needed	2025-2029	\$30-\$35
Otonabee TS 44kV: Station Capacity	Transfer 8MW of load from Otonabee 44kV bus to Dobbin TS	2022	\$0.1
Port Hope TS: Transformers T3/T4 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2026	\$25
Belleville TS: Build new DESN	Build a new 230 kV 75/125 MVA DESN with associated capacitor banks at the existing Belleville TS site	2026	\$35-\$40
Picton TS: Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2025	\$14.5
Dobbin TS: T1/T2/T5 Auto Transformer Asset Renewal	Replace the end-of-life auto transformers with two new 150/250 MVA unit and switchyard refurbishment	2029	\$100

*Hydro One is exploring whether Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

The Study Team recommends that:

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

⁷ Planning estimates are provided for Hydro One's portion of the work based on 2020 costs and are subject to change in the future

⁸ The new standard units are expected to have a higher LTR of about 160 MW

9. REFERENCES

- [1]. 1st Cycle Peterborough to Kingston Regional Planning Report(2016)
<https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/peterboroughtokingston/Documents/RIP%20Report%20-%20Peterborough%20to%20Kingston%20Region.pdf>
- [2]. Independent Electricity System Operator, “Peterborough to Kingston: Integrated Regional Resource Plan”, November 4, 2021
- [3]. <https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Peterborough-to-Kingston/p2k-IRRP-20211104.ashx>
- [4]. Independent Electricity System Operator, “Peterborough to Kingston: Integrated Regional Resource Plan - Appendices”, November 4, 2021
<https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Peterborough-to-Kingston/p2k-IRRP-appendices-20211104.ashx>
- [5]. 2nd Cycle Peterborough to Kingston Needs Assessment Report (2020)
<https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/peterboroughtokingston/Documents/RIP%20Report%20-%20Peterborough%20to%20Kingston%20Region.pdf>

APPENDIX A: STATIONS IN THE PETERBOROUGH TO KINGSTON REGION

Station	Voltage (kV)	Supply Circuits
Ardoch DS (T1)	115	B1S
Battersea DS (T1/T2)	115	S1K
Belleville TS (T1/T2)	230	T25B, H23B
Dobbin DS (T1/T2)	115	P3S, P4S
Dobbin TS (T3/T4)	115	Q20H, Q20A
Frontenac TS (T3/T4)	115	B5QK, Q3K
Gardiner TS (T1/T2)	230	X4H, X2H
Gardiner TS (T3/T4)	230	X2H, X4H
Harrowsmith DS (T1/T2)	115	B5QK
Hinchinbrooke DS (T1)	115	B5QK
Lodgeroom DS (T1/T2)	115	B1S
Napanee TS (T1)	230	X21, X22
Northbrook DS (T1)	115	B1S
Otonabee TS (T1/T2)	230	T22C, T31H
Otonabee TS (T1/T2)	230	T22C, T31H
Picton TS (T1/T2)	230	X21, X22
Port Hope TS (T1/T2)	115	P3S, P4S
Port Hope TS (T3/T4)	115	P3S, P4S
Sharbot DS (T1)	115	B5QK
Sidney TS (T1/T2)	115	Q12AT, Q6S

APPENDIX B: TRANSMISSION LINES IN THE PETERBOROUGH TO KINGSTON REGION

Location	Circuit Designations	Voltage (kV)
Hinchinbrooke SS – Lennox TS	X1H, X2H, X3H, X4H	230
Picton TS – Lennox TS	X21, X22	230
Belleville TS – Hinchinbrooke SS	H23B	230
Hinchinbrooke SS – Havelock TS	H27H	230
Dobbin TS – Chenaux TS	X1P	230
Dobbin TS – Chat Falls GS	C27P	230
Clarington TS – Havelock TS	T32H	230
Chat Falls GS – Havelock TS	C25H	230
Clarington TS – Chat Falls GS	T22C	230
Cherrywood TS – Dobbin TS	P15C	230
Clarington TS – Belleville TS	T25B	230
Dobbin TS – Sidney TS	P3S, P4S	115
Cataraqui TS – Sidney TS	Q6S	115
Barrett Chute TS – Sidney TS	B1S	115
Cataraqui TS – Frontenac TS	Q3K	115
Cataraqui TS – Frontenac TS to Barrett Chute TS	B5QK	115

APPENDIX C: DISTRIBUTORS IN THE PETERBOROUGH TO KINGSTON REGION

Distributor Name	Station Name	Connection Type
Eastern Ontario Power Inc.	Frontenac TS	Dx
Elexicon Energy Inc. – Veridian Connections Inc.	Belleville TS	Tx
	Port Hope TS	Dx
Hydro One Distribution	Ardoch DS	Tx
	Battersea DS	Tx
	Belleville TS	Tx
	Dobbin DS	Tx
	Dobbin TS	Tx
	Frontenac TS	Tx
	Gardiner TS	Tx
	Harrowsmith DS	Tx
	Hinchinbrooke DS	Tx
	Lodgeroom DS	Tx
	Napanee TS	Tx
	Northbrook DS	Tx
	Otonabee TS	Tx
	Otonabee TS	Tx
	Picton TS	Tx
	Port Hope TS	Tx
	Sharbot DS	Tx
	Sidney TS	Tx
	Dobbin DS	Dx
	Dobbin TS	Dx
	Otonabee TS	Dx
Kingston Hydro Corporation	Frontenac TS	Tx
	Frontenac TS	Dx
	Gardiner TS	Dx
Lakefront Utilities Inc.	Port Hope TS	Dx

APPENDIX D: AREA STATIONS LOAD FORECAST

Table D-1: Net Summer Coincidental Load Forecast (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ardoch DS	2	2	2	2	2	2	2	2	2	2	2	2
Battersea DS	9	9	9	9	9	9	9	9	9	9	9	9
Belleville TS	170	174	179	183	186	186	187	187	188	189	190	191
Dobbin DS	6	6	6	6	6	6	6	6	6	6	6	6
Dobbin TS	111	111	117	122	123	123	125	126	127	129	131	132
Frontenac TS	97	96	100	102	104	104	105	107	108	109	111	112
Gardiner TS (T1/T2)	146	148	151	152	153	154	155	156	158	159	161	163
Gardiner TS (T3/T4)	25	28	28	28	28	28	28	28	28	28	28	28
Harrowsmith DS	16	16	16	16	16	16	16	16	16	16	17	17
Havelock TS	74	74	74	75	74	74	75	75	76	76	76	77
Hinchinbrooke DS	6	6	6	6	6	6	6	6	6	6	6	6
Lodgeroom DS	9	9	9	9	9	9	9	9	9	9	9	9
Napanee TS	61	62	62	63	63	64	64	65	66	66	67	68
Northbrook DS	6	6	6	6	6	6	6	6	6	6	6	6
Otonabee TS	123	124	119	119	115	115	116	118	119	120	122	124
Picton TS	43	43	44	44	44	45	45	45	46	46	47	47
Port Hope TS	121	121	122	122	122	122	123	123	124	124	125	126
Sharbot DS	4	4	4	4	4	4	4	4	4	4	4	4
Sidney TS	79	79	79	79	79	79	79	80	80	81	81	82
CTS	14	14	14	14	14	14	14	14	14	14	14	14
Total	1122	1132	1147	1161	1163	1166	1174	1182	1192	1199	1212	1223

Table D-2: Net Winter Coincidental Load Forecast (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ardoch DS	3	3	3	3	3	3	3	3	3	3	3	3
Battersea DS	11	11	11	11	11	11	11	11	11	11	11	11
Belleville TS	164	167	171	175	179	179	180	181	182	183	184	185
Dobbin DS	6	6	6	6	6	6	6	6	6	6	6	6
Dobbin TS	87	87	93	98	99	100	101	102	104	105	106	107
Frontenac TS	101	101	104	106	109	109	111	112	113	115	116	118
Gardiner TS (T1/T2)	132	133	135	137	139	140	141	143	144	146	147	149
Gardiner TS (T3/T4)	29	32	32	32	32	32	32	33	33	33	33	33
Harrowsmith DS	19	19	19	19	19	19	19	19	19	19	19	19
Havelock TS	69	69	69	69	70	70	70	71	71	72	72	73
Hinchinbrooke DS	7	7	7	7	7	7	7	7	7	7	7	7
Lodgeroom DS	10	10	10	10	10	10	10	11	11	11	11	11
Napanee TS	70	70	71	71	72	72	73	74	75	75	76	77
Northbrook DS	7	7	7	7	7	7	7	7	7	7	7	7
Otonabee TS	145	146	146	142	138	139	140	142	143	146	147	149
Picton TS	48	49	49	50	50	50	51	51	52	52	53	53
Port Hope TS	127	128	128	129	130	130	130	131	132	132	133	134
Sharbot DS	4	4	4	4	4	5	5	5	5	5	5	5
Sidney TS	69	69	68	68	68	68	69	70	70	71	71	72
CTS	26	26	26	26	26	26	26	26	26	26	26	26
Total	1134	1144	1159	1170	1179	1183	1192	1205	1214	1225	1233	1245

Table D-3: Net Summer Load Forecast for stations with capacity needs (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	170	174	179	183	186	186	187	187	188	189	190	191
Frontenac TS	101	101	108	107	107	107	108	109	110	111	112	114
Gardiner TS (T1/T2)	146	148	151	152	153	154	155	156	158	159	161	163
Otonabee TS 44 kV	102	102	98	98	95	95	96	97	98	99	100	102

Table D-4: Net Winter Load Forecast for stations with capacity needs (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	164	167	171	175	179	179	180	181	182	183	184	185
Frontenac TS	111	113	117	117	117	118	119	120	121	122	123	125
Gardiner TS (T1/T2)	132	133	135	137	139	140	141	143	144	146	147	149
Otonabee TS 44 kV	115	116	116	113	109	110	111	113	114	115	116	118

Table D-5: Net Summer Non-Coincidental Load Forecast Growth Scenario 1 (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	170	174	179	183	187	187	187	188	189	190	191	192
Frontenac TS	101	102	109	110	111	113	117	121	125	129	133	137
Gardiner TS (T1/T2)	146	148	151	153	155	156	158	159	161	163	165	168

Table D-6: Net Winter Non-Coincidental Load Forecast Growth Scenario 1 (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	164	168	172	176	180	180	181	182	183	184	185	186
Frontenac TS	111	114	119	120	121	124	128	132	136	140	144	148
Gardiner TS (T1/T2)	132	134	136	138	141	142	144	146	148	150	152	155

Table D-7: Net Winter Non-Coincidental Load Forecast Growth Scenario 2 (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	164	168	172	176	180	180	181	182	183	184	185	186
Frontenac TS	111	116	124	126	130	136	145	155	165	174	183	193
Gardiner TS (T1/T2)	132	135	138	142	145	148	151	154	157	160	163	167

APPENDIX E: LIST OF ACRONYMS

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

**PETERBOROUGH TO KINGSTON IRRP
(NOVEMBER 2021)**



Peterborough to Kingston Integrated Regional Resource Plan

November 4, 2021

Table of Contents

1 Introduction	6
2 The Integrated Regional Resource Plan	8
2.1 Near- to Medium-Term Plan	8
Recommended Actions	8
2.2 Long-Term Plan	10
Recommended Actions	10
3 Development of the Plan	12
3.1 The Regional Planning Process	12
3.2 Peterborough to Kingston IRRP Development	12
4 Background and Study Scope	14
4.1 Study Scope	14
4.2 Related Bulk System Planning Studies	16
5 Electricity Demand Forecast	17
5.1 Demand Forecast Methodology	17
5.2 Historical Electricity Demand	18
5.3 Gross Demand Forecast Starting Point	19
5.4 Gross Demand Forecast	20
5.5 Contribution of Conservation to the Forecast	21
5.6 Contribution of Distributed Generation to the Forecast	22
5.7 Planning Demand Forecast	24
5.8 Non-Coincident Station Forecasts	26
5.9 Sensitivity Scenario: Retirement of Distributed Generation Resources	26
5.10 Sensitivity Scenario: High Growth Forecasts	27
5.11 Load Profiling	28
6 Power System Needs	29
6.1 Needs Assessment Methodology	29

6.2 Near/Medium-Term Needs	30
Station Capacity Needs	30
Supply Capacity Needs	34
End-of-Life Refurbishment Needs	37
Summary of Near/Medium-Term Needs	37
6.3 Long-Term Needs	37
Supply Capacity Needs	37
Summary of Long-Term Needs	39
6.4 Needs Summary	39
7 Plan Options and Recommendations	41
7.1 Options for Meeting Near- to Medium-Term Needs	41
Options for Meeting Station Capacity Needs	41
Options for Addressing Supply Capacity Needs	45
End-of-Life Refurbishment Options and Recommendations	46
Build a new 230 kV DESN transformer station at Belleville TS and monitor load growth	46
Hydro One (Distribution) load transfer and advance end-of-life replacement at Gardiner TS DESN #1	47
Monitor load growth and initiate development and siting work to build a new 230 kV DESN transformer station in Kingston when needed	47
Address implementation and cost allocation barriers to cost-effectively deploying non-wires alternatives to defer needs	47
Complete the ongoing Gatineau Corridor End-of-Life Study and implement recommendations	47
Upgrade Cataraqui autotransformers' secondary conductors and reassess as part of the Lennox to St. Lawrence bulk system study	48
Replace Port Hope TS T3/T4 with the closest available standard size transformers	48
7.2 Options for Meeting Long-Term Needs	48
Option for Meeting Supply Capacity Needs	48
7.3 Recommended Long-Term Plan	48
Monitor the Peterborough to Quinte West 115 kV system voltage performance following the recommendations of the Gatineau Corridor End-of-Life Study	49
Monitor Kingston Area Transmission Supply Capacity Needs	49

Monitor demand growth, conservation achievement and distributed generation uptake	49
Initiate the next regional planning cycle early, if needed	49
7.4 Summary of Recommended Actions and Next Steps	49
8 Engagement	52
8.1 Engagement Principles	52
8.2 Creating an Engagement Approach for Peterborough to Kingston	52
8.3 Engage Early and Often	53
8.4 Bringing Municipalities to the Table	55
Engaging with Indigenous Communities	55
8.5	55
9 Conclusion	56

List of Abbreviations

CDM	Conservation Demand Management
DER	Distributed Energy Resources
DESN	Dual Element Spot Network
DG	Distributed Generation
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
MW	Megawatt
NERC	North American Electric Reliability Corporation
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
TS	Transformer Station
TSC	Transmission System Code
Working Group	Technical Working Group of the Peterborough to Kingston Region

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

This IRRP was prepared on behalf of the Technical Working Group (Working Group) of the Peterborough to Kingston region, which is composed of the following licensed transmitters and licensed distributors:

- Elexicon Energy Inc. (Elexicon)
- Hydro One Networks Inc. (Distribution) (Hydro One (Distribution))
- Hydro One Networks Inc. (Transmission) (Hydro One (Transmission))
- Independent Electricity System Operator (IESO)
- Lakefront Utilities Inc. (Lakefront Utilities)
- Utilities Kingston
- Eastern Ontario Power

The Working Group assessed the adequacy of electricity supply to customers in the Peterborough to Kingston region over a 20-year period beginning in 2019; developed a plan that considers opportunities for coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

The Working Group developed a plan that considers the potential for long-term electricity demand growth in the region and maintains the flexibility to accommodate changes to key conditions over time.

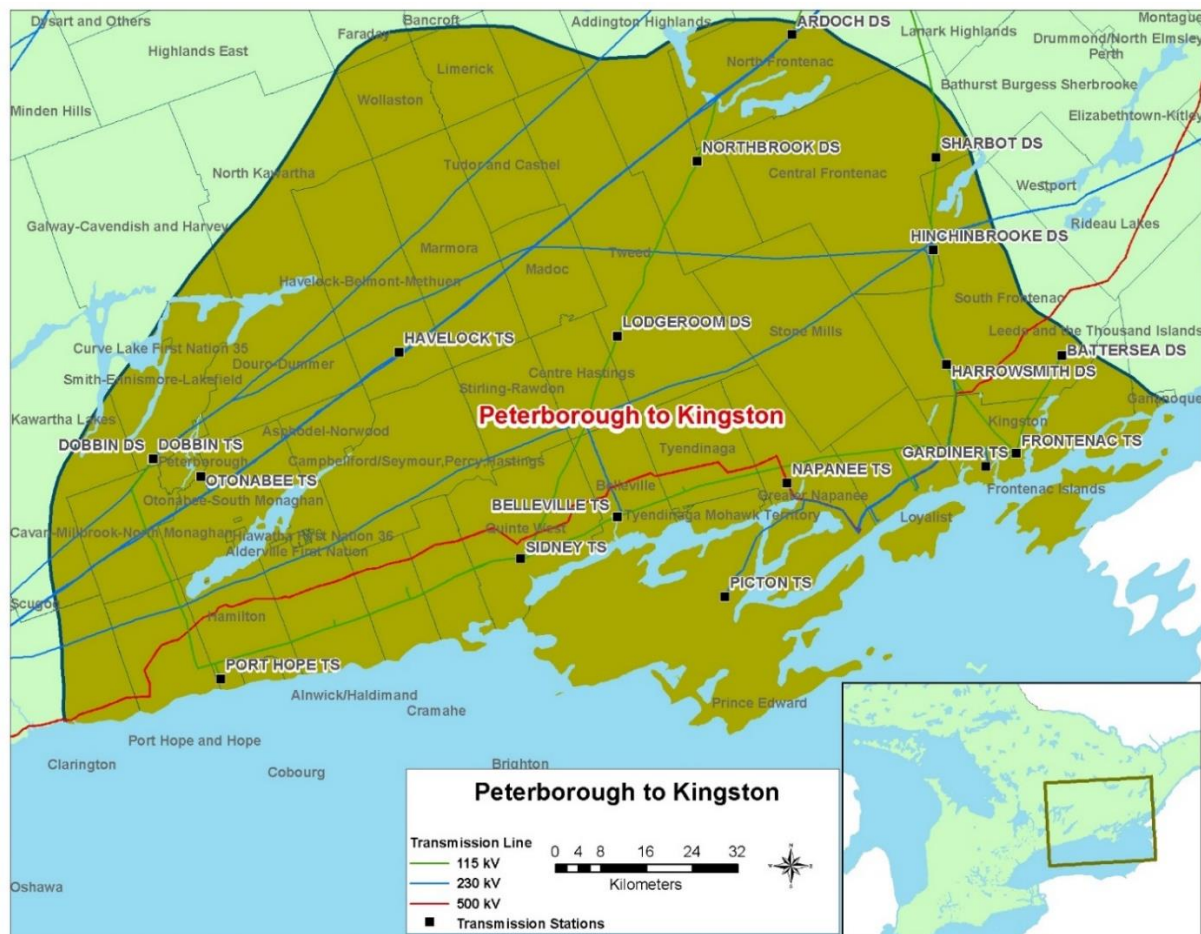
The Working Group members agree with the IRRP's recommendations and support implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community engagement and consultations.

1 Introduction

The Peterborough to Kingston region is located in eastern Ontario as shown in

Figure 1-1. It includes Frontenac County, Hastings County, Northumberland County, Peterborough County, Prince Edward County, parts of Lennox and Addington County, and related municipalities. Peterborough, Belleville and Kingston are the three largest population centres in the region. The region also comprises several Indigenous communities including Alderville First Nation, Hiawatha First Nation, Curve Lake First Nation, Mohawks of the Bay of Quinte, Tyendinaga Mohawk, Kawartha Nishnawbe and the traditional territory of the Huron Wendat.

Figure 1-1 | Overview of the Peterborough to Kingston Region and Transmission System



The region is supplied by the following local distribution companies:

- Elexicon which serves Port Hope and Belleville;
- Eastern Ontario Power, which is embedded to Hydro One Distribution, serves over 3,500 distribution customers in Gananoque, Ontario;
- Lakefront Utilities, embedded to Hydro One Distribution, serves 10,000 distribution customers across the Town of Cobourg and the Village of Colborne;

- Kingston Utilities serves 28,000 distribution customers in Central Kingston; and
- Hydro One Distribution¹, which supplies distribution customers in the surrounding areas of the region.

These LDCs receive power at the step-down transformer stations and distribute it to end users, i.e., industrial, commercial and residential customers.

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

This IRRP identifies needs pertaining to power system capacity, reliability requirements, and end-of-life asset replacement and coordinates options to meet customer needs in the area over a 20-year period. Given forecast uncertainty, the longer development lead time and the potential for technological change, the plan does not recommend specific investments or projects to meet mid- and long-term needs, but maintains the flexibility to evolve in step with emerging developments. Instead, this IRRP focuses both on recommendations to meet near-term needs, and on the near-term actions required to lay the groundwork for determining options to meet mid- and long-term needs.

The focus of this IRRP is providing an adequate reliable supply to support community growth. A key consideration in this analysis is whether near-term actions maintain, or act as a barrier to, long-term options. The recommended near-term actions are intended to be completed before the next IRRP cycle, scheduled for 2025, or sooner, depending on demand growth or other factors. In some cases, the scope of near-term actions includes the continuation of defined planning activities coordinated among key stakeholders to develop and complete recommendations within a specific time period. The completion of these actions will inform decisions for the next scheduled planning cycle, or sooner, particularly around integrated solutions that address multiple needs, as well as demand-side options and capabilities for which sufficient information is not currently available.

This report is organized as follows:

- A summary of the recommended plan for the Peterborough to Kingston region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the Peterborough to Kingston region and the study scope are discussed in Section 4;
- The demand outlook scenarios, and energy efficiency and distributed energy resource (DER) assumptions, are described in Section 5;
- Electricity needs in the Peterborough to Kingston region are presented in Section 6;
- Alternatives and recommendations for addressing the needs are described in Section 7;
- A summary of engagement activities to date and moving forward, is provided in Section 8; and
- A conclusion is provided in Section 9.

¹ Includes former Peterborough Distribution which was sold to Hydro One Distribution serves distribution customers in Peterborough, Lakefield, and Norwood.

2 The Integrated Regional Resource Plan

This Integrated Regional Resource Plan (IRRP) provides recommendations to address the electricity needs of the Peterborough to Kingston region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC)² and reliability standards governed by the North American Electric Reliability Corporation (NERC).

This IRRP identifies three planning horizons: from the base-year (2019)³ through the near term (up to 2024), medium term (year 6 to 10, through to 2029), and longer term (year 11 to 20, or through to 2038). These planning horizons reflect the inverse relationship between the length of time and demand certainty (in that the longer the outlook, the less certain it is), lead time for electricity resource development, and planning commitment required.

This IRRP identifies and recommends specific projects for implementation in the near term. This is necessary to ensure that they are in-service in time to address the area's more urgent needs, respecting the lead-time for development of the recommended projects or actions. This IRRP also identifies possible long-term electricity needs, some of which may advance to the near or medium term for a high growth scenario. However, as these needs are forecast to arise in the future, it is not necessary, nor would it be prudent given forecast uncertainty and the potential for technological change, to commit specific projects at this time. Instead, near-term actions are identified to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle so that their results can inform further discussion at that time or so the Working Group can respond in a timely manner, if a high growth scenario were to materialize.

2.1 Near- to Medium-Term Plan

The plan to meet the near-and medium-term needs of electricity customers in the Peterborough to Kingston region was developed to maximize the use of the existing electricity system in consideration of planning criteria such as reliability, cost, and feasibility. The near-term plan was also developed to be consistent with the long-term development of the region's electricity system.

The Working Group's recommendations for the near- and medium-term plan focus on addressing both station capacity needs in Belleville and Kingston and supply capacity needs on pockets of the 115 kV system. The area's near-term supply capacity needs in the Peterborough and Quinte West area are impacted by ongoing bulk system planning activities in the area. Further planning studies to assess bulk system impacts are also identified. The recommendations are summarized below.

Recommended Actions

1. Build a new 230 kV Dual Element Spot Network (DESN) transformer station at Belleville TS

² Refer to ORTAC for details: <http://www.ieso.ca/-/media/files/ieso/Document%20Library/Market-Rules-and-Manuals-Library/market-manuals/market-administration/IMO-REQ-0041-TransmissionAssessmentCriteria.pdf>

³ To be consistent with Regional Plan's Needs Assessment, the 2019 was used as a base year

To address today's station capacity need at Belleville TS, as well as to serve the growing electricity demand in the region, Exlexicon will work with Hydro One (Transmission) to initiate the development of a new Dual Element Spot Network (DESN) transformer station at Belleville, with an expected in-service date of 2025. This will increase the supply capacity to the region and will resolve the capacity need at Belleville TS until the end of the planning horizon.

2. Hydro One Distribution load transfer – Gardiner TS DESN #1 to Gardiner TS DESN #2

There is an immediate need for new capacity at Gardiner TS DESN #1. As a first step, performing a load transfer of 11 MW between Gardiner TS DESN #1 and Gardiner TS DESN #2 by 2022 is the cost-effective way to reduce load at Gardiner TS DESN #1. Although, a second load transfer of 11 MW can be performed, it comes with a high cost. Therefore, instead of performing a second load transfer, the next part of the solution is recommended action #3 - to advance end-of-life replacement of transformers at Gardiner TS DESN #1. After implementing first load transfer and recommended action #3, the Working Group will continue to monitor load at Gardiner TS DESN #1 and, evaluate if a second 11 MW load transfer is needed.

3. Hydro One Transmission to advance end-of-life replacement of transformers at Gardiner TS DESN #1

The station transformers at Gardiner TS DESN #1 are reaching end-of-life in the mid-2020s. Replacement of these transformers with units of a higher limited time emergency rating (LTR) is recommended as soon as possible (2024-2025), as the need is imminent. Advancing the replacement date, combined with the load transfer in recommended action #2, will address the Gardiner TS DESN #1 capacity need for the duration of the planning horizon for the reference load forecast and for the mid-term horizon for the high growth load forecast

4. Monitor load growth and initiate development and siting work to build a new 230 kV DESN transformer station in Kingston when needed

Building a new 230 kV station in Kingston will address the local need for station capacity at both Frontenac TS and Gardiner TS over the long term and for multiple growth scenarios. Due to the uncertainty in the forecast, the timing of the need for the new station could be in the near- to medium term or as late as 2029. Hence, Hydro One Distribution and Utilities Kingston will work together to monitor the load growth in their service areas, and work with Hydro One Transmission to commence the development work and subsequent construction of a new 230 kV station and required line connection, either transmitter or distributor owned, when it is deemed to be appropriate.

5. Address implementation and cost allocation barriers to cost-effectively deploying non-wires alternatives to defer needs

The development of a non-wire alternative, specifically additional energy efficiency or a local storage solution, could defer the new station ultimately required to accommodate load growth in the City of Kingston. This is cost-effective, under the reference load growth scenario, if cost-allocation can reflect the system benefits the non-wires alternative would provide. Additional barriers to implementation also exist around who would implement the solution and how they would seek cost-recovery, particularly if the transmitter or both benefiting LDCs were to implement a part of the solution. The IESO will work with the impacted transmitter and LDCs between regional planning cycles to address these barriers to implementation and cost allocation for a non-wires alternative, in tandem with developing plans for a new transformer station.

6. Complete the ongoing Gatineau Corridor End-of-Life Study and implement recommendations

The outcomes of the Gatineau Corridor End-of-Life Study will improve the supply capability in the Peterborough to Kingston region. Namely, addressing the identified supply capacity need to the Peterborough and Quinte West area. By implementing the recommendations of the Gatineau Corridor End-of-Life study this need should be addressed.

7. Upgrade Cataraqui autotransformers' secondary conductors and reassess as part of the Lennox to St. Lawrence bulk system study

Upgrading the autotransformers' secondary conductors will increase the thermal capacity of these autotransformers from 250 MW to 285 MW and will resolve the thermal violation after losing one of the autotransformers. A future Lennox to St. Lawrence bulk system study will reassess the need with this solution in place and study if additional capacity is required.

8. Replace Port Hope TS T3/T4 with the closest available standard size transformers

Port Hope TS T3/T4 are reaching end-of-life and there are no opportunities for end-of-life optimization at this time. This IRRP recommends like-for-like replacements with the closest available standard size transformers of equal or greater capacity.

2.2 Long-Term Plan

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

Recommended Actions

1. Implement Conservation

The implementation of provincial conservation targets is a key near-term action of the Peterborough to Kingston region's long-term plan. In developing the demand forecast, peak demand impacts associated with meeting provincial targets were assumed before identifying the residual needs.

Meeting provincial conservation targets amounts to approximately 73 MW, or 5% of the total forecast demand growth, by the end of the study period.

To ensure these savings materialize, it is recommended that conservation efforts be focused as much as possible on measures that will contribute to meeting program energy targets while also maximizing peak demand reductions. The monitoring of conservation success will lay the foundation for the long-term plan by evaluating the performance of specific conservation measures in the sub-region and assessing potential for additional conservation.

2. Study the potential bulk system impact of future supply reinforcement to Belleville TS

After building a new 230 kV station at Belleville, the transmission system supply into Belleville is expected to meet the load growth over the 20-year planning horizon. However, beyond this time horizon, the system supply capability will be limited due to excessive voltage change violations during contingency conditions. To solve this issue, transmission reinforcement to Belleville might be necessary. Before the next planning cycle, the bulk system impact of transmission reinforcement to Belleville TS should be included in the scope of a relevant individual bulk planning study for the area.

3. Monitor the Peterborough to Quinte West 115 kV system voltage performance following the recommendations of the Gatineau corridor end-of-life study

Low voltage violations are observed during contingency conditions in the long-term planning horizon on the 115 kV system in the Peterborough to Quinte West area. These violations may naturally be resolved by the outcome of recommendations in the forthcoming Gatineau corridor end-of-life study; therefore, this need will be monitored and re-assessed during the next planning cycle.

4. Monitor demand growth, conservation achievement and distributed generation uptake

On an annual basis, the IESO, with the Working Group, will review CDM achievement, the uptake of provincial DG projects, and actual demand growth in the Peterborough to Kingston Region. This information will be used to determine when decisions on the long-term plan are required, and to inform the next cycle of regional planning for the area. Information on CDM and DG is also a useful input into the ongoing development of non-wires alternatives as potential long-term solutions.

5. Initiate the next regional planning cycle early, if needed

Along with the indices outlined above, the Working Group will monitor changes in growth targets, progress in electrification in the region, and any significant changes in forecast growth. If monitoring activities determine that the region's growth is exceeding the load forecast (the high demand forecast in Belleville and Kingston, or the reference demand forecast in the remainder of the region), it may be necessary to initiate the next iteration of the regional planning process earlier than 2025 given the lead time for the long-term supply options.

3 Development of the Plan

3.1 The Regional Planning Process

In Ontario, planning to meet an area's electricity needs at a regional level is completed through the regional planning process, which assesses regional needs over the near, medium, and long term, and develops a plan to ensure cost-effective, reliable electricity supply. A regional plan considers the existing transmission electricity infrastructure, local supply resources, forecast growth and area reliability; evaluates options for addressing needs; and recommends actions to be undertaken.

The current regional planning process was formalized by the OEB in 2013, and is conducted for each of the province's 21 electricity planning regions by the IESO, transmitters and local distribution companies (LDCs) on a five-year cycle.

The process consists of four main components:

- 1) A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs;
- 2) A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
- 3) An IRRP, led by the IESO, which identifies recommendations to meet needs requiring coordinated planning; and
- 4) A Regional Infrastructure Plan (RIP) led by the transmitter, which provides further details on recommended wires solutions.

More information on the regional planning process and the IESO's approach to regional planning can be found in Appendix B - Development of the Plan.

In addition to regional planning process, there are bulk planning and distribution planning processes. Distribution system planning is for system at 44 kV and lower, while bulk and regional planning are for higher voltages. Furthermore, regional planning focuses more on a particular, local part of the grid, while bulk planning reviews electricity transfers across the province. There are inherent overlaps in all three levels of electricity infrastructure planning.

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

3.2 Peterborough to Kingston IRRP Development

Development of the Peterborough to Kingston IRRP was initiated in 2020 with the release of the Needs Assessment report. This product was prepared by Hydro One (Transmission) with participation from the IESO, Elexicon Energy, Hydro One (Distribution), Lakefront Utilities, Eastern Ontario Power, and Utilities Kingston. Screening for needs was carried out to identify needs that may require coordinated regional planning. The subsequent Scoping Assessment Outcome Report, which was prepared by the IESO, recommended that an IRRP should be developed to address previously identified and new needs in this region due to the potential for coordinated solutions.

In 2020, the Working Group was formed to develop finalize Terms of Reference for this IRRP, gather data, identify near- to long-term needs in the region, and recommend actions to address them.

4 Background and Study Scope

This is the second cycle of regional planning for the Peterborough to Kingston region. During the first cycle of regional planning, a Needs Assessment⁴ was conducted for the Peterborough to Kingston region in February 2015 that was led by Hydro One Networks Inc. Transmission, and included representatives from the IESO, the former Veridian Connections Inc., Kingston Hydro, and the former Peterborough Distribution Inc. and Hydro One Networks Inc. Distribution. After reviewing the needs identified in the report, the participants recommended that further regional coordination was not required, and instead the needs would be addressed through a local study.

This cycle of regional planning identified a number of needs requiring further regional coordination and recommended an IRRP be initiated. This report presents an integrated regional electricity plan for the next 20-year period starting from 2019⁵.

4.1 Study Scope

This IRRP, prepared by the IESO on behalf of the Working Group, recommends options to meet the electricity needs of Peterborough to Kingston region over near- to medium-term timeframe and sets out near-term actions required to ensure that options remain available to address long-term needs. Guided by the principle of maintaining an adequate level of reliability performance as per the Ontario Resource and Transmission Assessment Criteria (ORTAC)⁶, this IRRP reviews needs identified and discussed as part of the Scoping Assessment, with the focus on:

- Providing an adequate, reliable supply to support community growth;
- Minimizing the impact of supply interruptions; and
- Coordinating and aligning end-of-life asset replacements with evolving needs.

Given that parts of the Peterborough to Kingston region's 230 kV and 115 kV transmission networks also serve as major pathways for the flow of power to and from adjacent regions (Greater Toronto Area and Ottawa) and the connection of large generation facilities, the IRRP assesses the Peterborough to Kingston region 230 kV and 115 kV networks under certain system conditions. A detailed assessment of the bulk electricity system examining various bulk system conditions is typically undertaken through a separate planning process, as described in section 4.2, and is beyond the scope of this IRRP.

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

230 kV connected stations: Belleville TS, Dobbin TS, Gardiner TS, Havelock TS, Napanee TS, Otonabee TS, Picton TS and a customer owned station.

115 kV connected stations: Ardoch DS, Battersea DS, Dobbin DS, Frontenac TS, Harrowsmith DS, Hinchinbrooke DS, Lodgeroom DS, Northbrook DS, Port Hope TS, Sharbot DS, Sidney TS, and four customer owned stations.

⁴ The 2015 Needs Assessment Report for the Peterborough to Kingston Region is available on the Hydro One website ([link](#))

⁵ To be consistent with Regional Plan's Needs Assessment, the 2019 was used as a base year

⁶ The Ontario Resource and Transmission Assessment Criteria is available on the IESO website ([link](#))

230 kV transmission lines: C27P, H23B, H27H, P15C, T22C, T25B, T31H, T32H, X1H, X1P, X21, X22, X2H, X3H and X4H.

115 kV transmission lines: B1S, B5QK, P3S, P4S, Q3K, Q3M6, Q6S and S1K.

230/115 kV autotransformers: Dobbin T1, T2⁷, T5 and Cataraqui T1 & T2.

Electricity to the Peterborough to Kingston region is supplied primarily through the 500 kV station Lennox TS, located in Lennox and Addington County, in conjunction with a number of 230 kV transmission lines from Clarington TS and Cherrywood TS, both located in the GTA East area. A large portion of the load in the Peterborough to Kingston region is connected to a regional 115 kV system, supplied by the 230 kV transmission system through five (5)⁷ 230-115 kV autotransformers located at Dobbin TS and Cataraqui TS.

The Peterborough to Kingston region can be broken out into a number of sub-systems or areas with common supply points/limitations, which includes Peterborough, Port Hope to Quinte West, Belleville, and Kingston.

- The Peterborough area is supplied by two step-down transformer stations, Dobbin TS and Otonabee TS. Power is delivered into this area through the 230 kV transmission circuits P15C, C27P, T22C and T31H running between GTA East and the Ottawa area.
- The Port Hope to Quinte West area is supplied by two step-down transformer stations, Port Hope TS and Sidney TS which are both served by the regional 115 kV system.
- The Belleville area is supplied by one step-down transformer station, Belleville TS which is supplied via the 230 kV transmission circuits T25B and H23B.
- Lastly, the Kingston area is supplied by three step down transformer stations, Frontenac TS, Gardiner TS #1 and Gardiner TS #2. Frontenac TS is supplied by the regional 115 kV system, whereas Gardiner TS (#1 & #2) are supplied by the 230 kV transmission circuits X2H and X4H.
- Together, the Peterborough area and the Port Hope to Quinte West area, form part of a larger electrical sub-system within the Peterborough to Kingston region, referred to as the Peterborough to Quinte West sub-system or area.

The Peterborough to Kingston IRRP was developed by completing the following steps:

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

⁷ Normally, Dobbin T2 is operated out of service

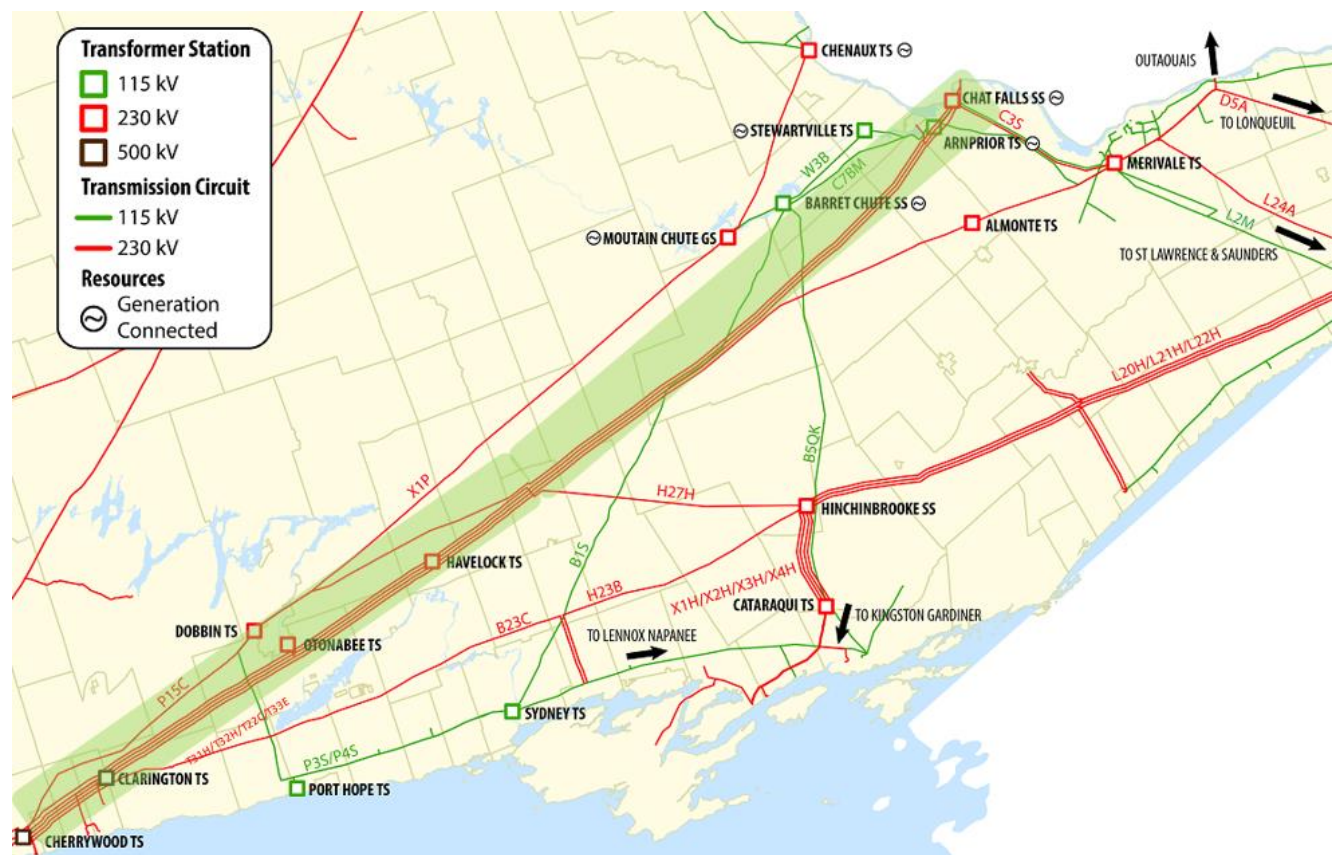
- Engaging with the community on needs, findings, and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

4.2 Related Bulk System Planning Studies

Gatineau Corridor End-of-Life Study

As shown in Figure 4-1, the Gatineau corridor consists of five (5) 230 kV transmission circuits stretching between GTA East and Ottawa area. As shown, these circuits form a major pathway on the bulk transmission system and provide or support supply to Ottawa and Peterborough, connection of Chats Falls area generation and imports from Quebec. The study assesses transmission equipment end-of-life needs forecast to arise over the next five to ten years, in addition to forecast reliability needs in the areas of Ottawa and Peterborough to Quinte West.

Figure 4-1 | Gatineau Corridor



The Gatineau corridor circuits are critical in supporting the regional 115 kV supply system, and in some cases directly supply step-down transformer stations (Dobbin TS and Otonabee TS). The options being assessed as part of the study have a direct impact on the supply to the Peterborough to Kingston region. Forecast needs between the Gatineau Corridor End-of-Life study and the Peterborough to Kingston regional planning studies have been coordinated, seeking opportunities for integrated solutions addressing both bulk and regional needs. The IESO's participation on the Working Group in the next stage of regional planning, the RIP, will help ensure recommendations are aligned with the latest bulk system information.

5 Electricity Demand Forecast

Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in the region. In order for the Working Group to plan for the future electricity needs of the region, a 20-year planning demand forecast was developed. This section outlines the demand forecast methodology, discusses historical electricity demand trends, development of the planning demand forecasts (both coincident and non-coincident) as well as the expected contributions of CDM and DG towards reducing the peak demand in the region. By taking all of these factors into consideration the planning demand forecast is developed and it is used to plan the transmission grid such that the grid can operate reliably and economically in the long term.

Furthermore, high growth forecast scenarios were developed to provide insight into the system's capability when faced with higher load than projected by the reference planning demand forecast. Two demand forecast sensitivity scenarios have been established and outlined in sections 5.9 and 5.10: a scenario where DG resources were expected to be out of service following their contract expiration, and a scenario to account for increased load growth, particularly in Kingston and Belleville, due to electrification.

5.1 Demand Forecast Methodology

For the purpose of the IRRP, a 20-year planning forecast was developed to assess electricity supply and reliability needs. Transmission infrastructure supplying an area is sized to meet peak-demand requirements (rather than energy demand requirements). Peak demand requirements are first determined at the station or DESN⁸ level, allowing capability in pockets where there is load growth, or where existing equipment has been historically close to its load supply capability, to be more accurately assessed. These forecasts are then aggregated to understand the limits of the transmission system and identify overall regional electricity needs during regional coincident peak times.

The planning forecast is divided notionally into four time horizons: present day, near, medium, and long term. The near term (one to five years) has the highest degree of certainty; any near-term needs are typically met using regional transmission or distribution solutions. Other methods (i.e., conservation and demand management (CDM) or DG) are considered in the near- to mid-term (six to 10 years), since lead times to develop and incorporate these options depend on the size of the need.

The long-term forecast covers the 10- to 20-year period and has the lowest degree of certainty. It is used to identify potential longer-term needs, and for the consideration and development of integrated solutions, including CDM, DG, and major transmission upgrades. Early identification of potential needs and possible solutions enables engagement with the local community and all levels of government long before the need is triggered, maximizes opportunities for input to inform decision-making, and helps ensure local planning can account for new infrastructure.

⁸ A dual-element spot network, or DESN, refers to a standard station layout used throughout the province, where two supply transformers are configured in parallel to supply one or two low-voltage switchgear which the distributor uses to supply load customers. This paralleled dual supply ensures a standard level of reliability where one supply transformer can be lost due to an outage or planned maintenance but supply to the customer can be maintained. A single local transformer station can have one, two, or more individual DESNs.

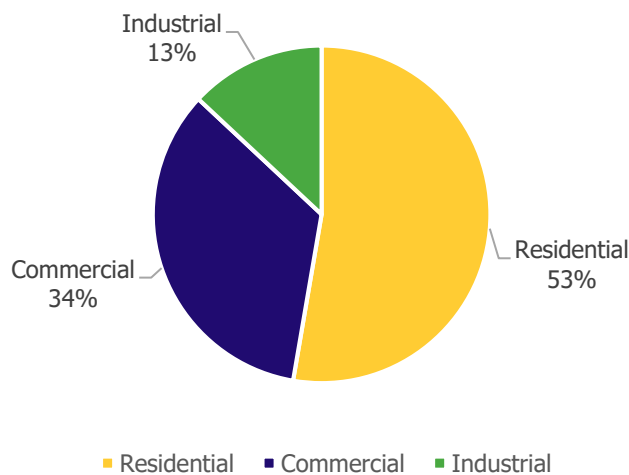
To address the long-term uncertainty in the electricity demand outlook, the robustness of the existing system was assessed to determine the capability of the existing system and its ability to supply customers, given possible outages and system states (e.g., contingencies).

Additional details on the demand outlook assumptions can be found in Appendix A - Methodology and Assumptions for Demand Forecast. The demand outlook was used to assess any growth-related electricity needs in the region.

5.2 Historical Electricity Demand

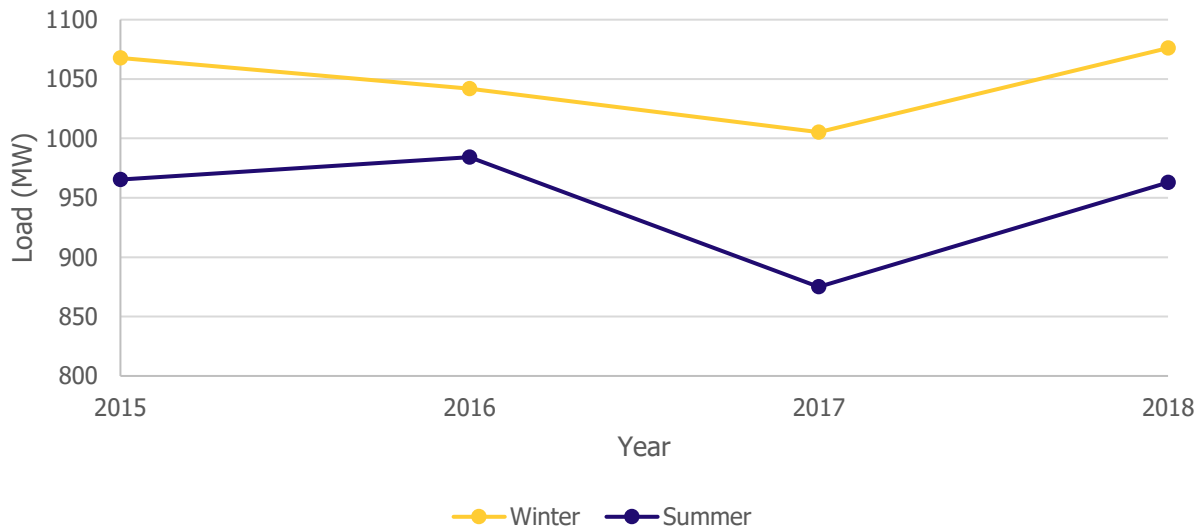
The Peterborough to Kingston region electricity demand is a mix of residential, commercial and industrial loads, encompassing diverse economic activities ranging from educational institutions to large business parks. As seen in Figure 5-1, the region's residential sector is the largest consumer of electricity accounting for approximately 50% of the peak load. The commercial and industrial sectors also have impactful contributions to the region's peak load, accounting for approximately 35% and 15% respectively. Peak demand can also be influenced by extreme weather conditions, with peaks in demand typically occurring after several days of extreme temperatures. In addition to weather, factors affecting commercial and industrial energy demand, such as increased economic activity, improvements in energy efficiency, and on-site generation development have impacts on the regional peak.

Figure 5-1 | Regional Sector Segmentation Data (Winter)



The regional historical loading data from 2015 to 2018 shows that the electricity system in the region has typically been winter-peaking. As shown in Figure 5-2, the coincident net peak demand in the region has been around 950 MW and 1050 MW in the summer and winter respectively. Upon review of the data, the Working Group determined that 2018 loading data would prove to be the most effective base year to use for the purposes of developing the planning load forecast. The regional peak in 2018 was approximately 1080 MW in the winter and 960 MW in the summer.

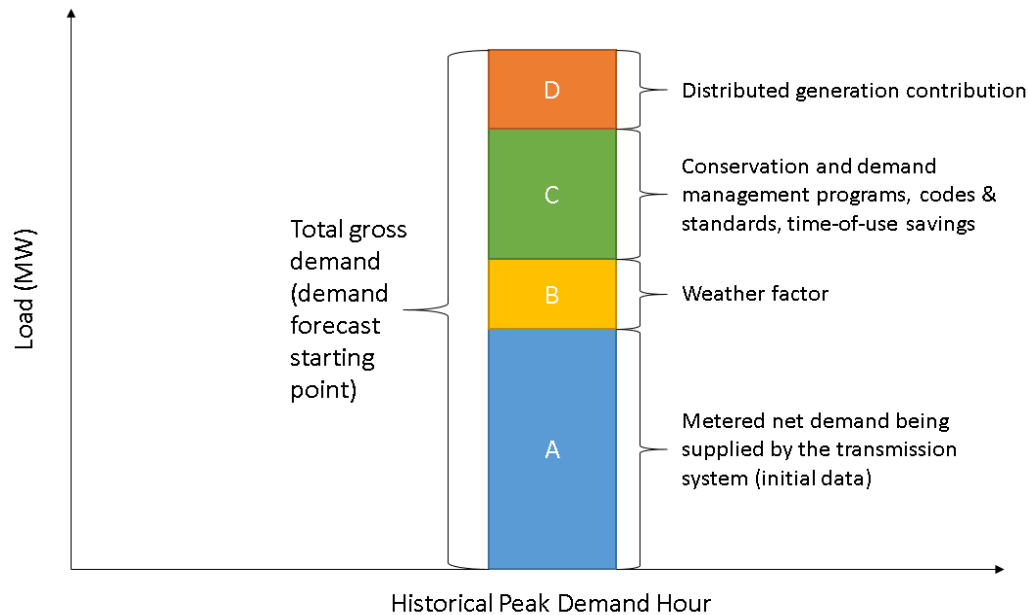
Figure 5-2 | Historical Net Peak Demand in the Peterborough to Kingston Region



5.3 Gross Demand Forecast Starting Point

To develop a forecast starting point, a net metered load data was obtained for all LDCs at each station within the region for both the summer and winter peak hours of 2018. The historical metered data is not a satisfactory representation of the true demand in the region as it does not account for the impacts of DG, CDM, and the effects of weather during a particular year. In order to account for the aforementioned factors, through a procedure known as the “unbundling” process, the Working Group established a new starting point to reflect the actual gross demand under median weather conditions. Having a gross demand starting point allows the LDCs to forecast growth from a starting point which represents the actual demand in the region, as opposed to simultaneously forecasting net load growth, DG, and CDM savings. This approach is summarized in Figure 5-3. Note that for the Peterborough to Kingston region, unbundling gross load was achieved to the extent for which the necessary data was available. For a more detailed look at the weather correction methodology see Appendix A.1 - Method for Accounting for Weather Impact on Demand.

Figure 5-3 | Normal/Extreme Weather Corrected Coincident Net and Gross Peak Demand in the Peterborough to Kingston Region



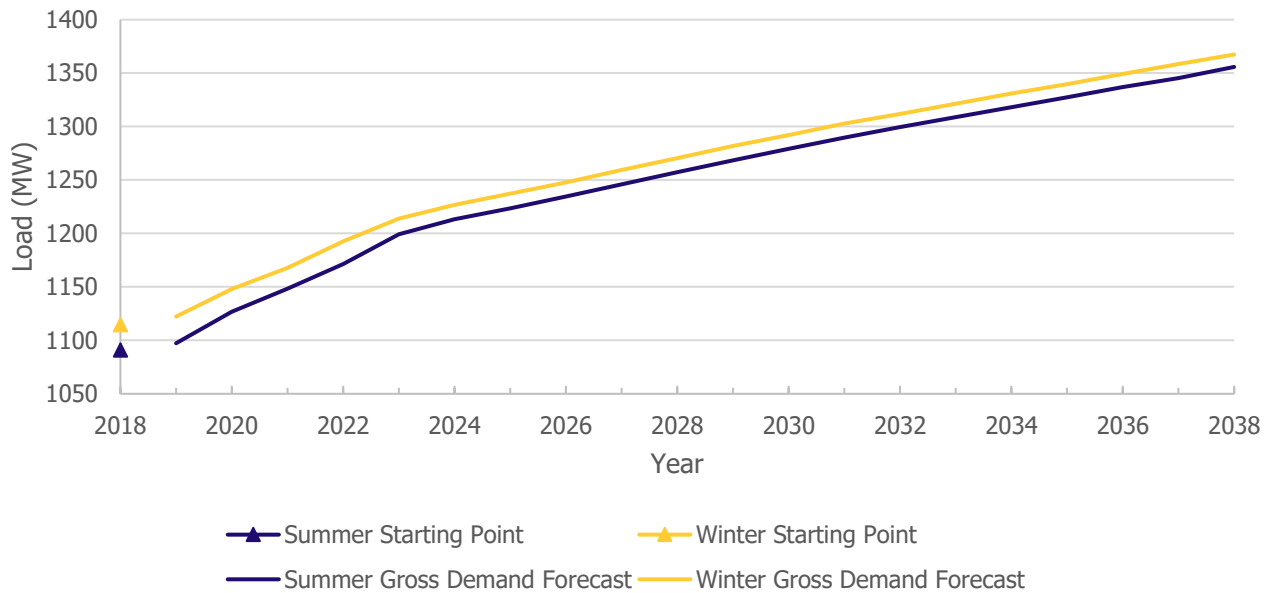
5.4 Gross Demand Forecast

Utilizing the established gross demand, median weather starting points, the LDCs provided 20-year forecasts at a station level. LDCs are tasked with the development of their own gross load forecasts at each station. This is due to the fact that LDCs have strong insights into customer and regional growth expectations over the planning horizon due to their direct relationship with customers. This insight includes known connection applications and knowledge regarding typical electrical demand for various types of customer groups.

The LDC forecasts account for increases in demand due to various factors such as new or intensified development, economic growth, population growth, changes in consumer behaviour, etc. It is noted that the gross demand forecast that was developed did not account for future DG or new conservation measures, such as codes and standards and demand response programs. These components were accounted for in later portions of the demand forecasting process as described in section 5.1. Most LDCs cited alignment with municipal and regional official plans as a primary source for input data. Other common considerations included known connection applications and typical electrical demand for similar customer types. For a more detailed look into each LDCs forecast methodology see Appendix A - Methodology and Assumptions for Demand Forecast.

Both the summer and winter median weather, gross demand forecasts are depicted in Figure 5-4.

Figure 5-4 | Coincident, Median Weather, Gross Demand Forecasts



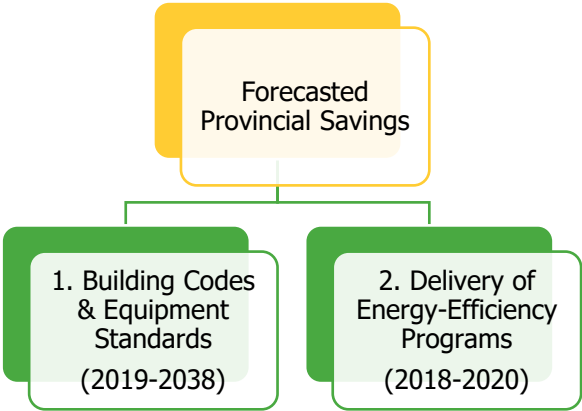
5.5 Contribution of Conservation to the Forecast

Conservation and Demand Management (CDM) is a clean and cost effective resource for helping to meet Ontario's electricity needs and has played an integral part in ensuring the development of a reliable and sustainable electricity system through provincial and regional planning. CDM is achieved through a mix of program-related activities, and mandated efficiencies from building codes and equipment standards. It plays a key role in maximizing the use of existing assets and maintaining reliable supply by offsetting a portion of a region's demand growth, and helping to ensure it does not exceed equipment capability.

Future CDM savings for the Peterborough to Kingston region have been projected out over the course of the 20-year planning horizon to take into account both policy-driven conservation through the provincial CDM Framework, as well as expected peak demand impacts due to building codes and equipment standards for the duration of the forecast.

To estimate the peak-demand impact of existing and committed CDM savings in the region, the forecast for provincial savings were divided into two main categories, as shown in Figure 5-5.

Figure 5-5 | Categories of Conservation & Demand Management Savings



For the Peterborough to Kingston region, the IESO worked with the LDCs to identify the breakdown of load per customer sector on a station level. The breakdown of load was divided into three categories: residential, commercial and industrial. This provided higher resolution when forecasting energy efficiency, as energy efficiency potential estimates vary by sector due to differing energy consumption characteristics and applicable measures.

The estimated impact of existing or committed CDM programs and codes and standards for the Peterborough to Kingston region have been applied to the gross demand extreme weather forecast, along with DG (as described in Section 5.7), to determine the net peak demand for the region. Additional details are provided in Appendix A - Methodology and Assumptions for Demand Forecast.

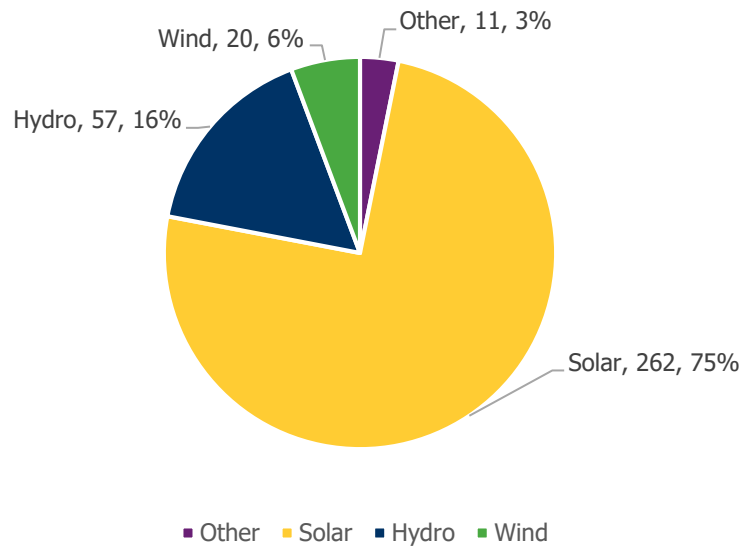
Table 5-1 | Reduction to Summer Demand Forecast due to Conservation

Year	2020	2022	2024	2026	2028	2030	2032	2034	2036	2038
Savings (MW)	15	35	61	74	80	82	80	75	72	72

5.6 Contribution of Distributed Generation to the Forecast

The IESO has contracts with several distributed generators in the Peterborough to Kingston region. For the purposes of the planning demand forecast only IESO contracted DG and significant behind the meter resources noted by the LDCs have been included when accounting for the DG resources in the region. A breakdown by fuel type of distributed generation resources in the region for the year 2019 is shown in Figure 5-6.

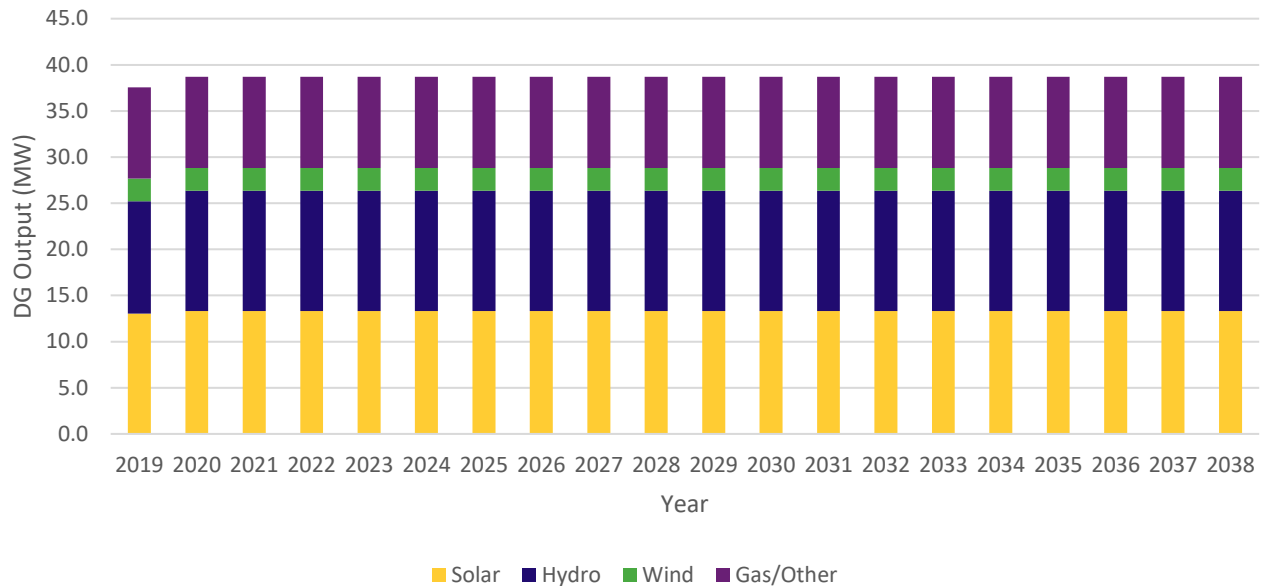
Figure 5-6 | Installed DG Capacity (MW,%) in the Peterborough to Kingston Region (2019) by Resource Type



The resources that were included in the DG forecast were comprised of a mix of solar, wind, hydroelectric and other (biogas, landfill gas and natural gas) projects. The majority of distributed generation in the region consists of solar resources (75% of total contracted installed DG capacity in 2019). Specific capacity contribution factors were attributed to each resource type in order to estimate the effective capacity that would be available to shave load during the regional peak hours. Upon applying the associated capacity contribution factors to each resource in the DG list, the data was then aggregated on a station level in order to put together a forecast specifying the estimated peak load reduction due to DG output. Figure 5-7 shows the contribution of DG output at the time of region's peak in the Peterborough to Kingston region by Resource Type.

Various DG contracts that have been administered by the IESO are set to expire during the 20-year planning horizon with the majority of those that will expire coming off contract in the final five years of the forecast period. For the purposes of the planning demand forecast, the Working Group decided to assume that contracts coming to the end of their terms will be reacquired by the IESO. Thus, the planning demand forecast assumed that all contracts will persist throughout the planning horizon. However, it was also deemed beneficial to create a sensitivity forecast scenario to explore how the needs identified through the technical study would evolve if all contracts did truly expire and behind the meter generation was not accounted for in the planning forecast. The sensitivity forecast is outlined in section 5.9.

Figure 5-7 | Contribution of DG output at the time of region's peak in the Peterborough to Kingston Region by Resource Type



5.7 Planning Demand Forecast

The final planning demand forecast was used to carry out system studies, and was the primary input for identifying potential needs. It was prepared by first taking the gross median weather demand forecasts prepared by LDCs and adjusting them to account for the expected impact of extreme weather conditions (as described in section 5.5), thereby increasing demand. Furthermore, the impacts of CDM savings and DG were added (as described in the sections 5.6 and 5.7), which resulted in reducing the demand. The outcome of these steps results in the final planning demand forecast, which is an extreme weather net demand forecast. For a more detailed look into each LDCs forecast methodology see Appendix A - Methodology and Assumptions for Demand Forecast.

Figure 5-8 and Figure 5-9 shows the summer and winter planning demand forecast, aggregated for the entire Peterborough to Kingston region. For comparison, the figure also shows the net metered historical peaks from 2015-2018, the 2018 median weather corrected starting point, the gross median weather forecast and the gross extreme weather forecast.

Figure 5-8 | Summer, Extreme Weather, Net Demand Forecast

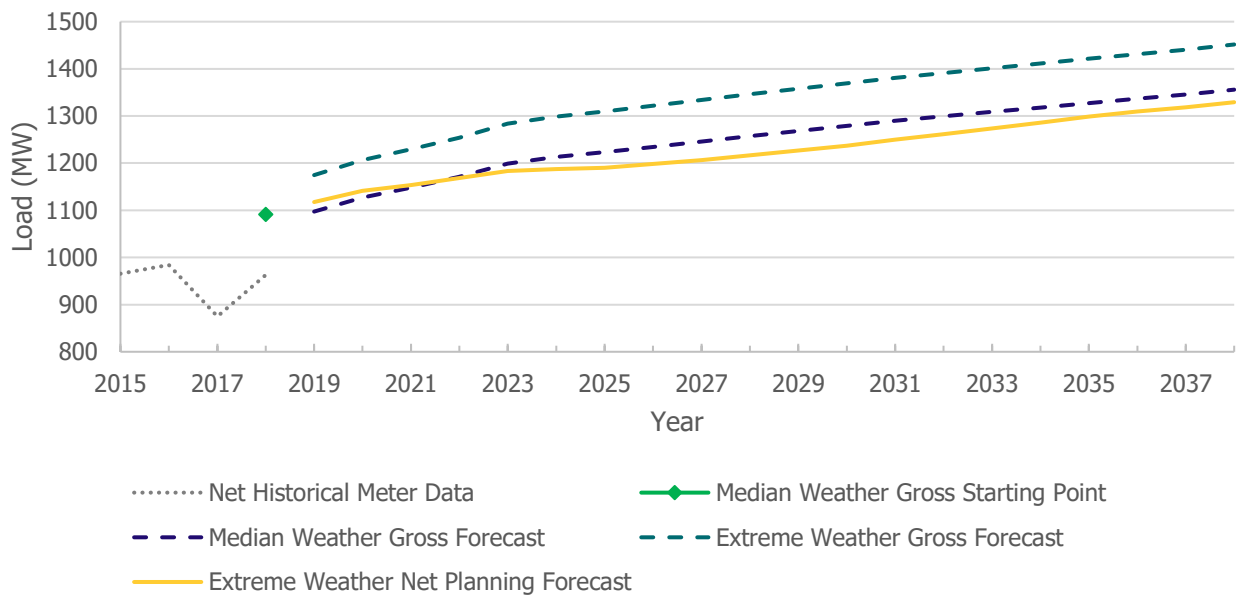
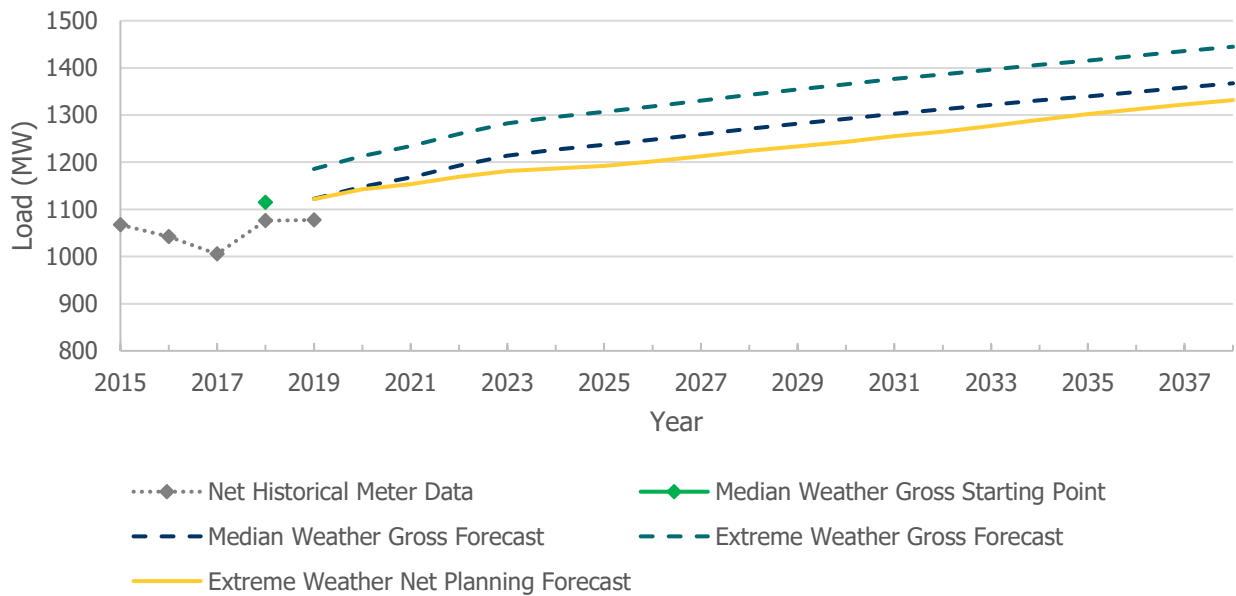


Figure 5-9 | Winter, Extreme Weather, Net Demand Forecast

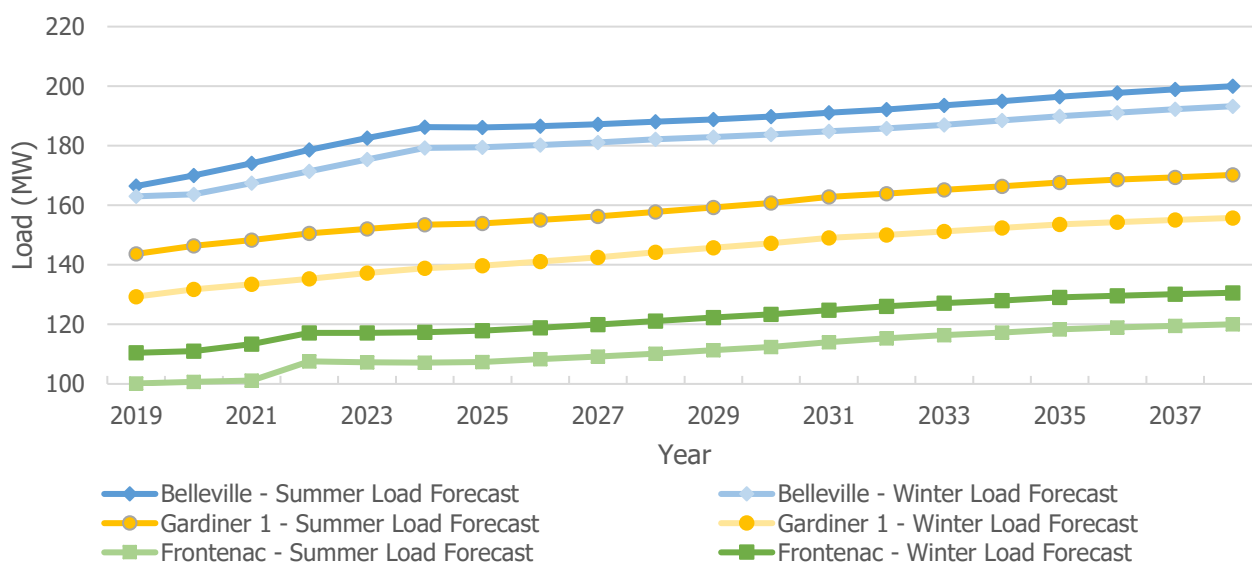


5.8 Non-Coincident Station Forecasts

To evaluate the adequacy of the electric system, the regional planning process involves measuring the demand observed at each station for the hour of the year when overall demand in the study area is at a maximum, also called the coincident peak demand. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether the stations' peaks occur at different times. Apart from assessing the adequacy of the electrical grid, the adequacy of each station is assessed as part of the regional planning process. For this assessment, non-coincident forecasts are created, as shown in Figure 5-10. If a station's non-coincident forecast loading exceeds the capability of each transformer at the station, this is an indication of a station capacity need.

The Scoping Assessment completed prior to the start of the IRRP had identified three stations which were likely to have station capacity needs over the course of the planning horizon; Belleville TS, Frontenac TS and Gardiner TS DESN #1. A further screening was completed by the Working Group during the IRRP to establish these needs.

Figure 5-10 | Summer and Winter Non-coincident Station level Planning Demand Forecast



5.9 Sensitivity Scenario: Retirement of Distributed Generation Resources

The development of the planning demand forecast assumed that contracts coming to the end of their terms will be reacquired by the IESO. The Working Group identified the need to look at the other bookend scenario; i.e., creating a sensitivity forecast which assumes that all DG resources are taken out of service following the expiry of their contracts. This scenario also assumed that non-IESO contracted behind the meter generators, accounted for by LDCs in the planning forecast, would not contribute towards reducing the gross demand forecast. This was due to the fact that there was little to no certainty with regards to the operation of these resources during times of regional peak.

With the assumption that expired contracts will retire, it was determined that it will not have a significant impact to region's demand as the DG contribution at the time of region's peak is approximately 40 MW as shown in Figure 5-7.

5.10 Sensitivity Scenario: High Growth Forecasts

The Working Group, in consultation with key customers, developed a high demand scenario. While the scenario developed is most impacted by the incorporation of potential impacts of electrification in the Kingston area (identified through stakeholder feedback), the rest of the region was also reviewed by the applicable LDCs to capture any relevant long-term growth plans or any currently foreseeable electrification impacts for their areas.

The City of Kingston had many stakeholders who were able to provide input into high growth forecast scenarios. This included projects ranging from electric vehicle charging infrastructure to electrified space heating installations. High growth forecasts for the City of Kingston thus added considerable load to the reference forecast.

Two high growth scenarios were developed, with high growth scenario 1 representing a more moderate impact from electric heating than high growth scenario 2. To develop the high growth scenario 2 winter demand scenario, the rated output of existing natural gas heating appliances (BTU/h) was converted to the equivalent electric resistive heating demand (kW). For the high growth scenario 1 winter demand scenario the electric resistive heating demand of high growth scenario 2 was converted to an equivalent electric heat pump demand. Since the differentiating factor between high growth scenario 1 and 2 was the assumption on the efficiency of conversion to electric space heating, only one high growth scenario (scenario 1) was developed for summer demand. Further details of the input to both forecast scenarios are presented in Appendix A.

Stakeholders serviced from Belleville TS were not able to provide detailed load growth information pertaining to electrification projects. As such, industry reports and data pertaining to electric vehicle demand as well as city growth statistics were used to create a high growth forecast resulting in an increase of another 3 MW by the year 2038. Further details on the high growth scenario for Belleville TS can also be found in Appendix A.

Table 5-2 | Different Forecast Scenarios - Summer

Summer Load Forecast	2020	2030	2038
Belleville - Reference Forecast	170	190	200
Belleville - High Growth Forecast	170	191	203
Kingston - Reference Forecast	247	273	290
Kingston - High Growth 1 Forecast	247	297	332

Table 5-3 | Different Forecast Scenarios - Winter

Winter Load Forecast	2020	2030	2038
Belleville - Reference Forecast	164	184	193
Belleville - High Growth Forecast	164	185	196
Kingston - Reference Forecast	243	270	287
Kingston - High Growth 1 Forecast	243	296	329
Kingston - High Growth 2 Forecast	243	347	415

5.11 Load Profiling

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20 year forecast horizon) for certain stations or group of stations with identified needs were developed to characterize their needs with finer granularity. The profiles are based on historical data adjusted for variables that impact demand such as calendar day (e.g. holidays and weekends) and weather (e.g. extreme weather events like ice storms or heat waves) impacts. The profiles are then scaled to match the annual peak forecast for each year. As described in section 7.1, these profiles are used to quantify the magnitude, frequency, and duration of needs to better evaluate the suitability of generation and distributed energy resource options.

Note that this data is used to roughly inform the overall energy requirements that a non-wire alternative would need to meet for the purposes of evaluating alternatives; the intent in this application is not to deterministically specify the precise hourly energy requirements. Further, the purpose of this data is to enable the selection of suitable technology types and roughly estimate operating costs. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification achieve greater adoption. The Working Group will continue to monitor these changes as part of plan implementation.

6 Power System Needs

Based on the demand outlook, system capability, application of provincial planning criteria, and the transmitter's identified end-of-life asset replacement needs, the Peterborough to Kingston IRRP Working Group determined electricity needs in the near, medium, and long term. This section describes end-of-life, capacity, and reliability needs in the Peterborough to Kingston region.

6.1 Needs Assessment Methodology

Based on the application of ORTAC⁹ and North American Electric Reliability Corporation (NERC) TPL 001-4 Standard¹⁰, the Working Group identified electricity needs local or regional reliability requirements for the following categories:

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

⁹ <https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/connecting/IMO-REQ-0041-TransmissionAssessmentCriteria.pdf>

¹⁰ <https://www.nerc.com/files/TPL-001-4.pdf>

- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC. No load security and restoration needs were identified as part of this IRRP.

6.2 Near/Medium-Term Needs

Station Capacity Needs

Station capacity needs have been identified for Belleville TS, Frontenac TS and Gardiner TS DESN #1 in the near or medium term. The following sections describe these capacity needs, along with the sensitivity of the need date to high growth forecasts (as described in section 5.10).

Belleville TS Station Capacity Need

Belleville TS consists of one DESN connected to the 230 kV system. The station has a summer capacity of 130 to 161 MW¹¹, depending on the load composition when transmission circuit H23B and the companion transformer are both lost. Currently, the station has reached the capability of the existing station transformers, be it 130 MW or 161 MW. Furthermore, the station's load is similar in summer and winter seasons, however, the transformer's summer ratings are lower than winter.

While the Belleville TS transformers are currently undergoing an end-of-life replacement, targeted in-service 2022, this refurbishment is not expected to result in a material improvement to the station's capacity. Based on historical and forecast demand, there is a capacity need at Belleville TS today.

Another 30 MW of load is forecast to connect to Belleville TS over the next 20 years. Figure 6-1 and Figure 6-2 show the various non-coincident forecast scenarios that were developed for Belleville TS for the summer and winter, respectively, along with the current capacity of the station. If a high growth scenario materializes, this capacity need would worsen.

¹¹ The 130 MW is a voltage limitation, while the 161 MW is a thermal limitation, and which one becomes more limiting is subject to the load composition.

Figure 6-1 | Summer Non-Coincident Demand Forecast Scenarios for Belleville TS

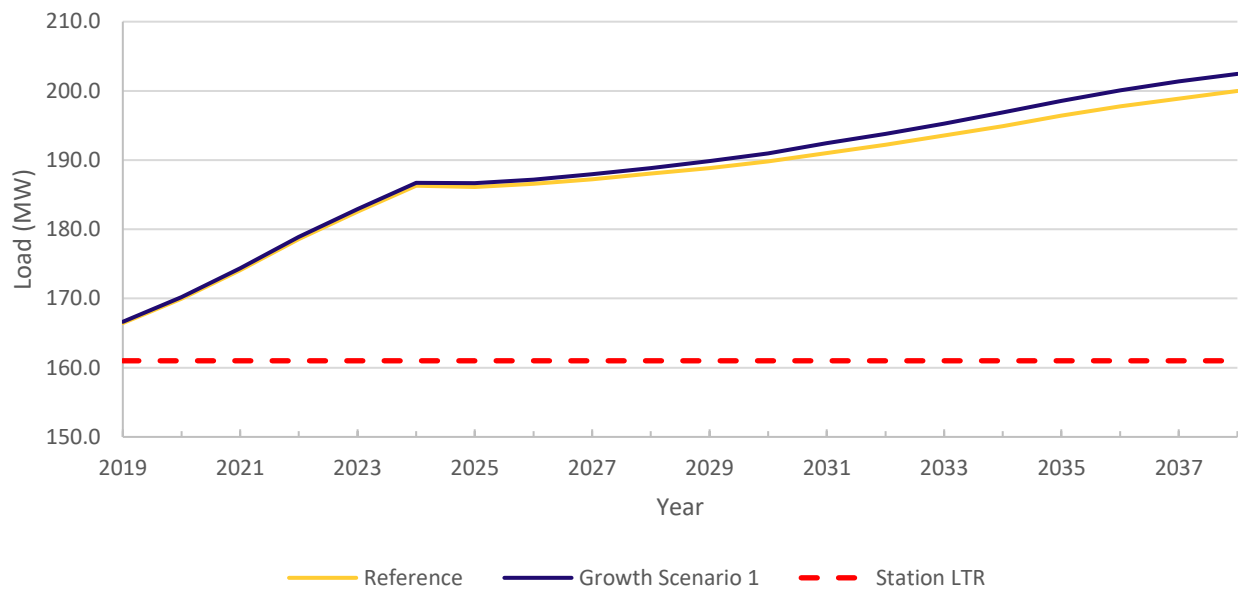
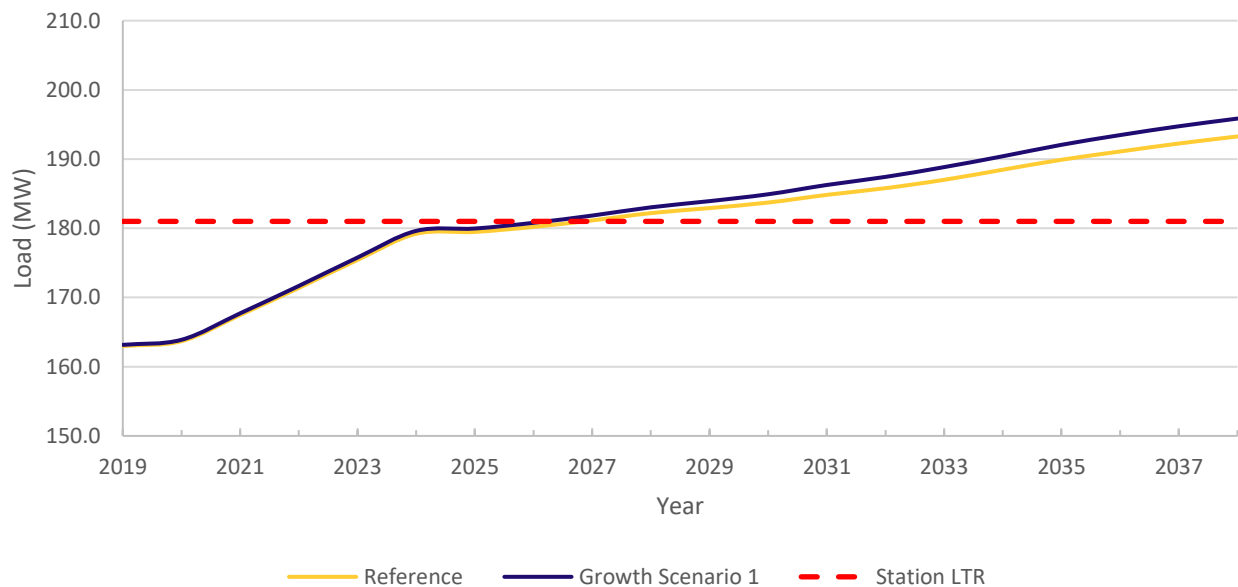


Figure 6-2 | Winter Non-Coincident Demand Forecast Scenarios for Belleville TS



Station Capacity Needs in the Kingston area

The City of Kingston is supplied by two station sites, Frontenac TS and Gardiner TS (which contains two DESNs, #1 and #2). These stations have overlapping service territories, and so, capacity needs in the region should be looked at holistically. There is significant growth forecast within the City of Kingston over the 20 year planning horizon, however, the magnitude varies considerably based on the forecast scenario considered – reference, high growth 1, and high growth 2. As can be expected, the station capacity needs can arise earlier under the high growth scenarios than for the reference forecast. The next two sections provide further details on the Frontenac TS and Gardiner TS station capacity needs.

Frontenac TS Station Capacity Need

The Kingston area distribution system is divided into two territories supplied by two different LDCs. The central area that contains the Kingston downtown core is supplied by Utilities Kingston while the remaining area to the west of Kingston's downtown core, as well as area the developments east of the Cataraqui River, are supplied by Hydro One (Distribution).

While the load growth is distributed throughout the area, the system is electrically supplied from two separate paths:

- (1) Frontenac TS is supplied from the 115 kV circuits B5QK and Q3K; and
- (2) Gardiners TS DESN #1 and #2 are supplied from the 230 kV circuits X2H and X4H.

The forecast load for Frontenac TS and Gardiner TS DESN #1 are both expected to exceed the stations' respective LTR in the near to mid term. The configuration of the distribution system in Kingston is such that there are frequent load transfers between Frontenac and Gardiner TS DESN #1 via 44 kV feeder ties which allow for added reliability during planned and emergency work. This flexibility will become more rigid if either Frontenac TS or Gardiner TS DESN #1 are loaded to their maximum capability. As a result, the reliability benefits of timely load restoration, the operational benefits for outage planning, and the identified capacity needs have to be balanced when planning an adequate system for the long term.

Throughout the planning process it became evident that the potential for rapid load growth is a risk for the area as a whole. High growth scenarios were developed which include the impact of future electrification programs such as electrification of fleet vehicles, thermal heat pumps, and fuel switching incentives. These high growth scenarios advance and amplify the two major capacity needs in the area.

Frontenac TS is supplied by two transformers with a total summer capacity of 111 MW. Figure 6-3 and Figure 6-4 show the various non-coincident demand forecast growth scenarios developed for Frontenac TS for the summer and winter seasons, respectively. The station's capacity (LTR) is included in the figure to identify the need. The figures illustrate the area is anticipated to exceed the current capacity by between 10 to 110 MW by 2038, depending on the forecast scenario. The station capacity need is anticipated to materialize as late as 2029 or as early as 2022, depending on the forecast scenario.

Figure 6-3 | Summer Non-Coincident Demand Forecast Scenarios for Frontenac TS

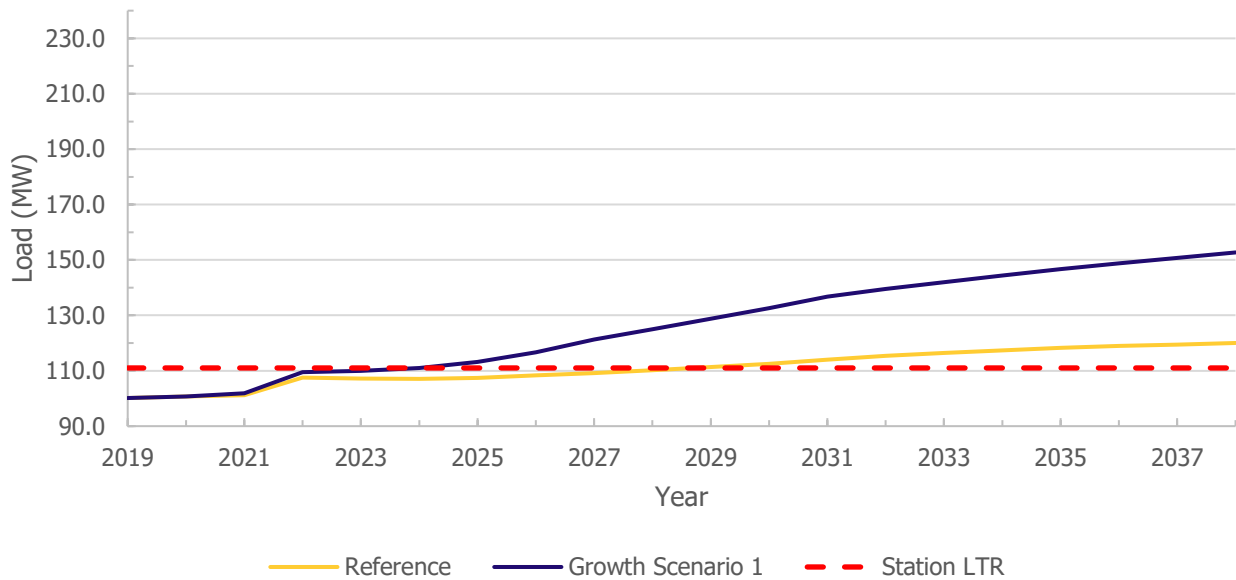
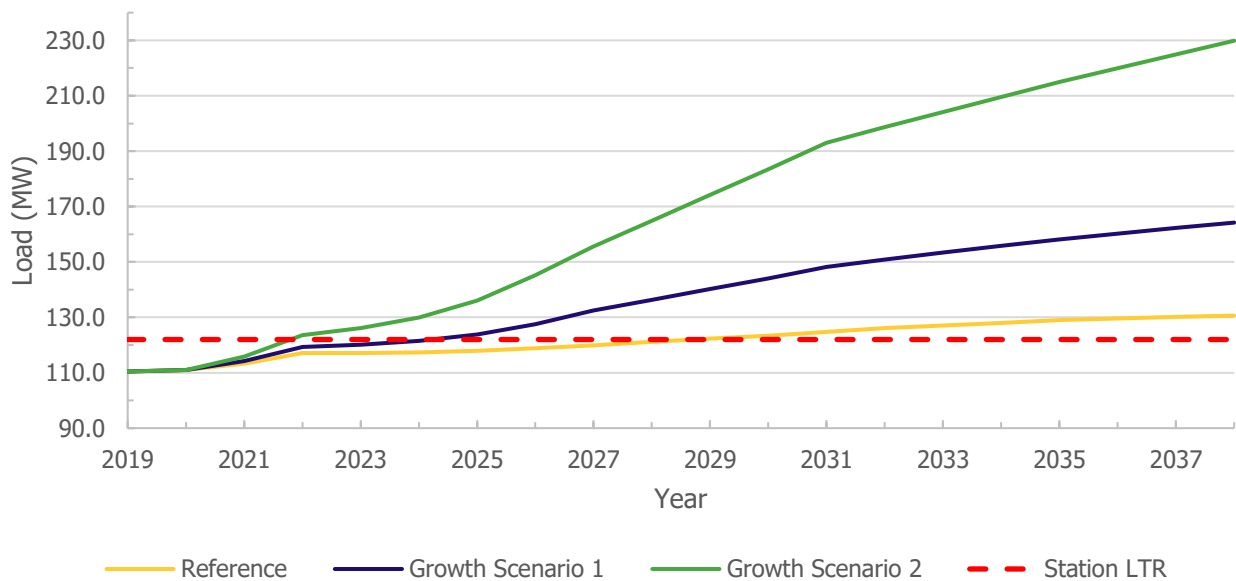


Figure 6-4 | Winter Non-Coincident Demand Forecast Scenarios for Frontenac TS



Gardiner TS (DESN #1) Station Capacity Need

A local capacity need was identified at the Gardiner TS DESN #1 within the Peterborough to Kingston region. Gardiner TS currently consists of two DESNs connected to the 230 kV system. The T1/T2 DESN (#1) has a summer capacity of 125 MW, while the T3/T4 DESN (#2) has a summer capacity of 85 MW. Gardiner TS DESN #2 is the newer of the two DESNs and has ample station capacity, while Gardiner TS DESN #1 has reached its capacity. Another 25 to 50 MW of load growth is forecast for Gardiner TS DESN #1, depending on the forecast scenario. Figure 6-5 and Figure 6-6 show the various forecast scenarios developed for Gardiner TS DESN #1 for the summer and winter, respectively. The station's capacity (LTR) is included in the figure to identify the need. It is also to be noted that Hydro One Transmission has identified that Gardiner TS DESN #1 is approaching end-of-life.

The figures illustrate that Gardiner TS DESN #1 has a summer capacity need today, and the magnitude of need increases for the high growth scenarios.

Figure 6-5 | Summer Non-Coincident Demand Forecast Scenarios for Gardiner TS DESN#1

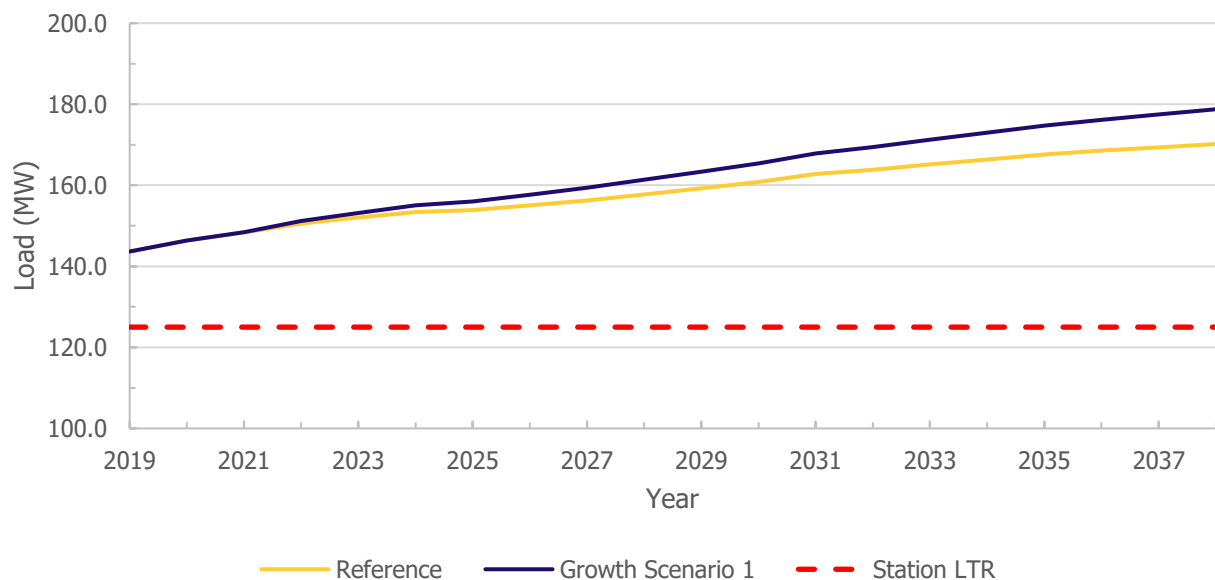
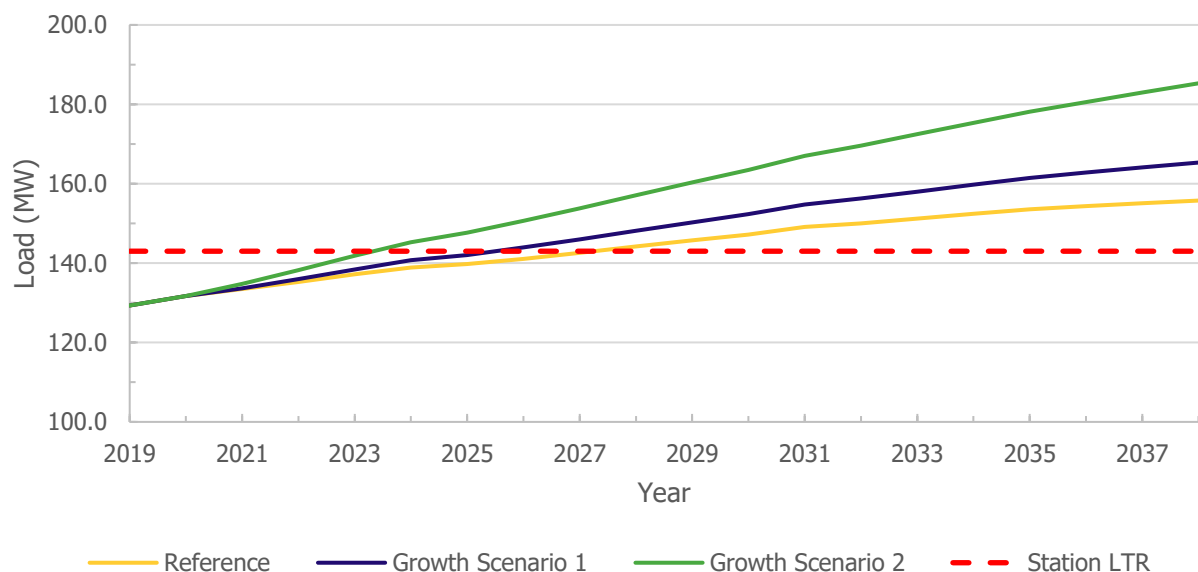


Figure 6-6 | Winter Non-Coincident Demand Forecast Scenarios for Gardiner TS DESN#1



Supply Capacity Needs

The Peterborough to Kingston region's electricity demand growth affects the 230 kV transmission supply capability to serve the 115 kV local area. While load growth is distributed throughout the area, two bulk supply capacity needs were observed, these are:

1. Supply lines affecting Peterborough to Quinte West load

2. Cataraqui autotransformer capability to support Frontenac and other 115 kV loads

These two bulk supply needs observed are described next. The impact of DG retirement is negligible as the region's demand increases slightly – ~40 MW.

Peterborough to Quinte West Supply Capacity needs

The load growth in the Peterborough to Quinte West sub-system is expected to introduce supply capacity needs in the area. There are 230 kV and 115 kV supply lines that serve load in that pocket. Specifically, P15C, a 230 kV single circuit from Cherrywood TS to Dobbin TS, and Q6S, a 115 kV single circuit supplying Sidney TS from Cataraqui TS, are two critical circuits supplying this load pocket. The limitation on these two circuits dictates a Load Meeting Capability (LMC) of 270 MW for the sub-system, shown on Figure 6-8. As shown in this figure, the sub-system load is expected to increase by approximately 60 MW over the 20-year planning horizon.

This need is being coordinated with bulk planning system study activities in the area to ensure impacts from the broader system are considered when reviewing and resolving this need.

Figure 6-7 | Critical Supply to Dobbin by Sidney (P15C and Q6S)

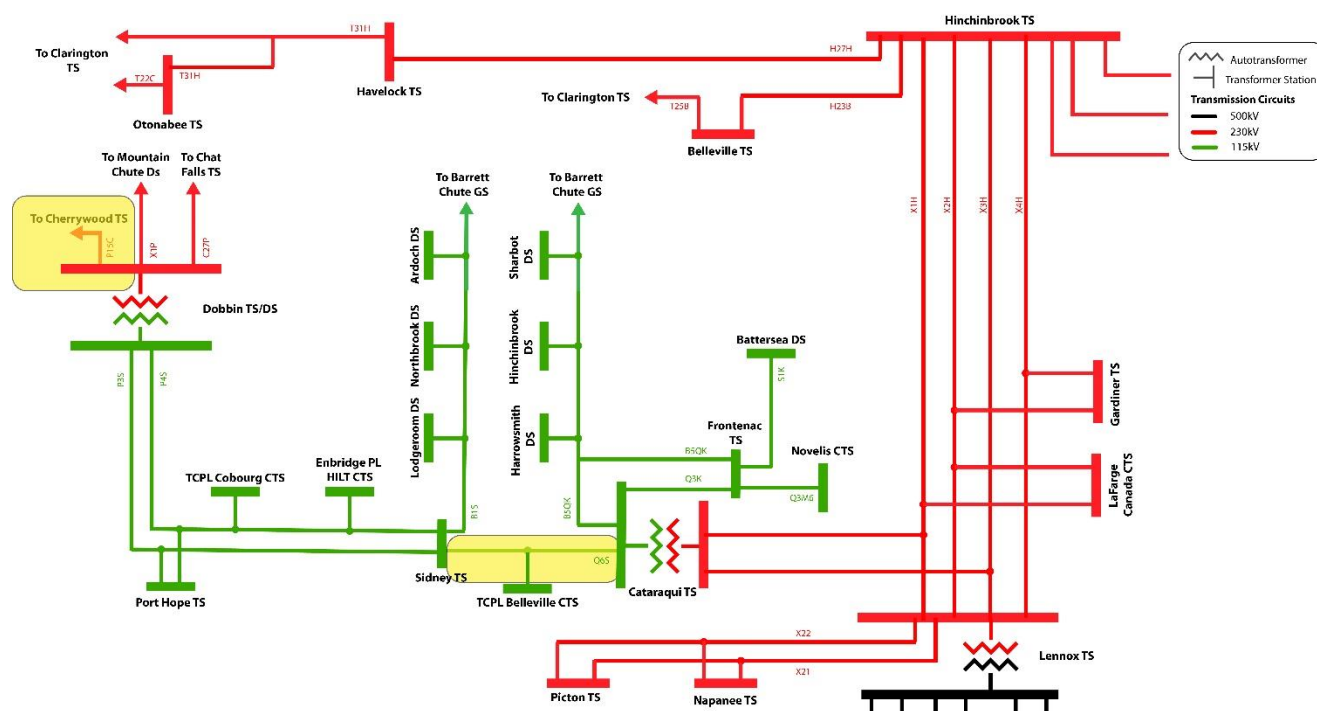
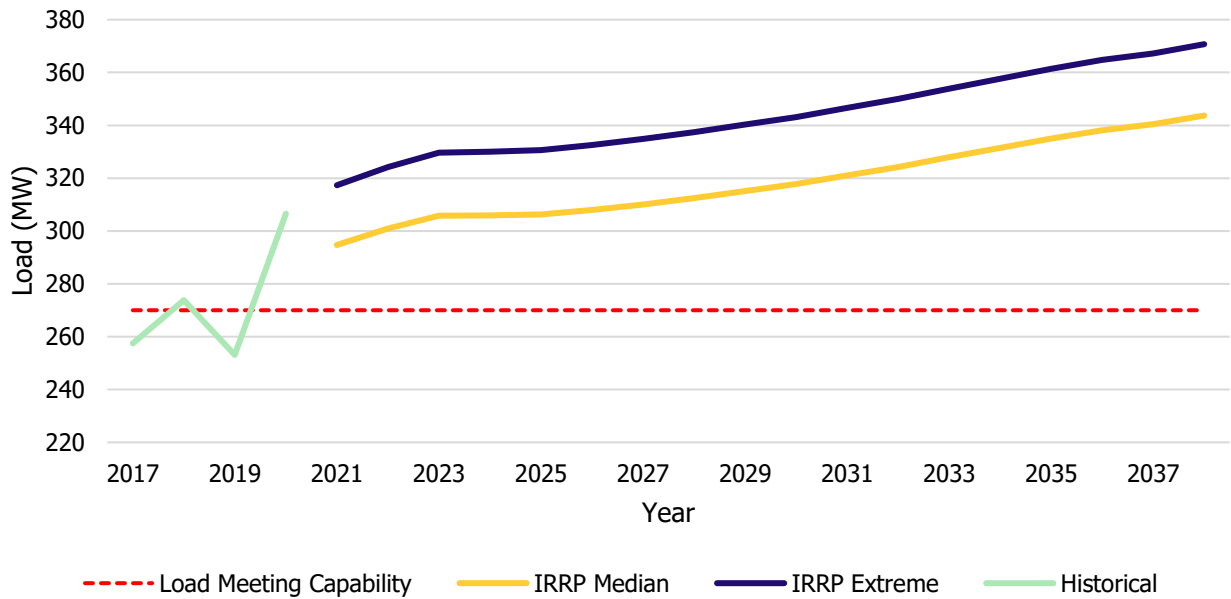


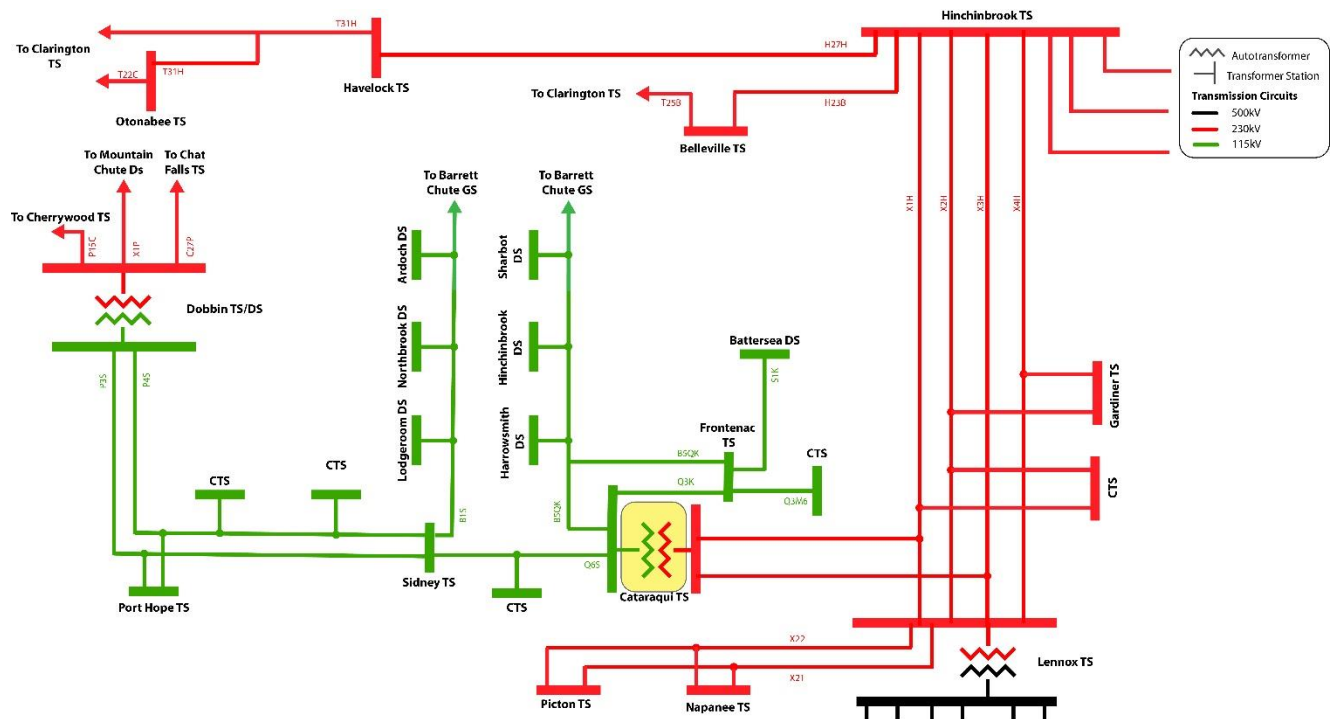
Figure 6-8 | Peterborough to Quinte West Forecast and LMC



Cataraqi Autotransformers Supply Capacity Need

The load growth at Frontenac TS and other 115 kV supply stations is expected to result in a supply capacity need at Cataraqi TS in 2023. The load is expected to continue to increase over the 20-year planning horizon.

Figure 6-9 | Cataraqi Autotransformers



End-of-Life Refurbishment Needs

The transmitter identified some end-of-life asset replacement needs for the Peterborough to Kingston region, with several needs arising in the near to medium term. These consisted of station transformer replacement needs. Based on the outcomes of the Needs Assessment and the Scoping Assessment, only one end-of-life need was identified as requiring further coordinated planning in the IRRP. Port Hope TS T3/T4 transformer replacement, currently expected to be needed in 2025 based on the latest asset condition information, was included in the IRRP. The end-of-life needs are based on the best available asset condition information at the time of each stage of the planning cycle, timing of asset needs can change as new information becomes available.

Summary of Near/Medium-Term Needs

	Needs	Location	Need Date ¹²
1	Station Capacity	Belleville TS	Today
2	Station Capacity & End-of-Life Refurbishment	Gardiner TS DESN #1	Today
3	Supply Capacity	Peterborough to Quinte West	Today
4	Supply Capacity	Cataraqui Autos	2023
5	End-of-Life Refurbishment	Port Hope TS	2025
6	Station Capacity	Frontenac TS	2029

6.3 Long-Term Needs

Supply Capacity Needs

The long-term load growth for the Peterborough to Kingston region results in supply capacity needs on the 115 kV system. While load growth is distributed throughout the area, the sub-system is electrically supplied from two separate paths:

1. 115 kV circuits supplying the Port Hope, Sidney, Lodgeroom DS area
2. B5QK circuit supplying the Frontenac TS area.

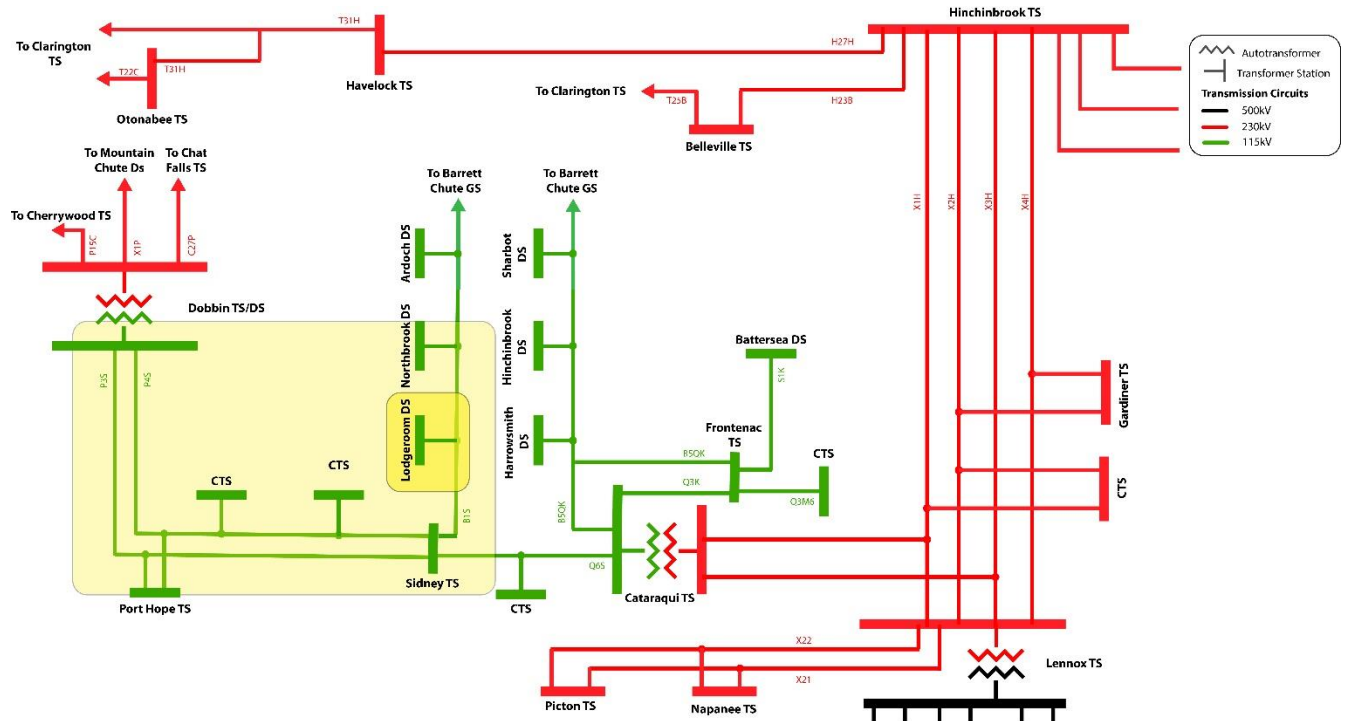
The local supply needs observed are described next. The impact of DG retirement is negligible as the region's demand increases slightly ~40 MW.

¹² Based on reference forecast. Impact of high growth is discussed within the relevant section.

Peterborough to Quinte West Voltage Need

The load on the 115 kV system is expected to grow by 60 MW over the 20 year planning horizon. It is expected to introduce voltage criteria violations in the area. During a pre-existing outage on circuit C27P, the loss of circuit P15C will result in under-voltage violations starting in 2033 at Lodgeroom DS. These conditions worsen and appear at additional stations on the 115 kV system in later years as load continues to grow, as depicted in Figure 6-10.

Figure 6-10 | 115 kV Pocket Voltage Need



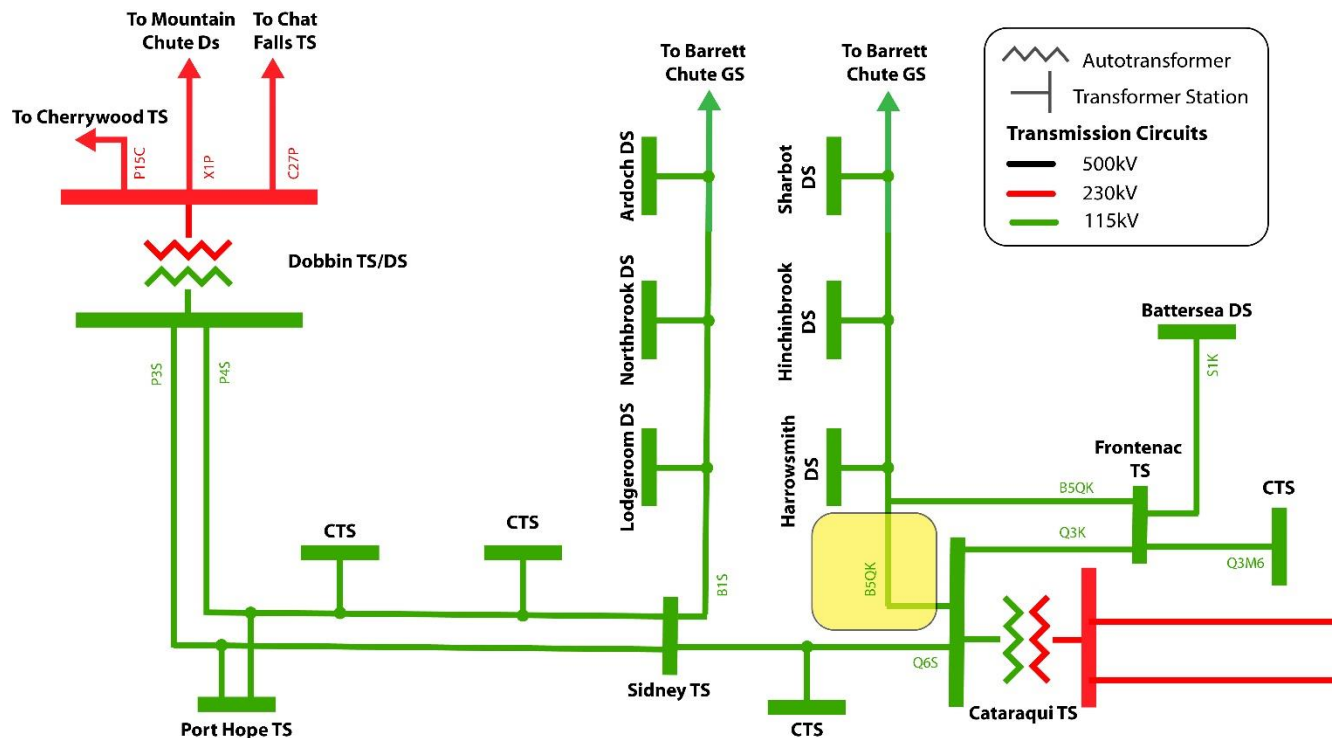
Kingston Transmission Supply Capacity Needs

The forecast load growth in Kingston, specifically at Frontenac TS, is expected to introduce supply capacity needs in the area. There are two upstream 115 kV supply lines serving Frontenac TS and one of them – B5QK¹³ highlighted on Figure 6-11– is forecast to exceed its capacity in the long term as the load grows by 27 MW to 165 MW¹⁴. This limit isn't expected to be exceeded until the end of the planning horizon for the reference forecast, but a need can emerge as early as 2027 or 2025, for high growth scenarios 1 and 2, respectively.

¹³ 1.1 KM section of B5QK from Cataraqui TS to the Railton JCT

¹⁴ Battersea DS, Frontenac TS, Harrowsmith DS, Hinchinbrooke DS, Sharbot DS, and 1 CTS

Figure 6-11 | B5QK overloaded section



Summary of Long-Term Needs

	Needs	Location	Need Date ¹²
1	Supply Capacity	Peterborough to Quinte West	2033
2	Supply Capacity	Kingston Area	2038

6.4 Needs Summary

The majority of the needs in the region are near- and medium-term station and supply capacity needs. Station capacity needs occur in the Belleville and Kingston areas and the supply capacity needs present on multiple portions of the 115 kV system in the region. The table below provides an overview of the needs considered in the development of options for the plan.

Table 6-1 | Summary of Needs

Area/Facility	Need	Description	Need Date ¹²
Belleville TS	Station Capacity	An existing capacity need was identified for Belleville TS, limited by voltage issues for the loss of one transmission supply as well as transformer capacity.	Today
Gardiner TS	Station Capacity & End-of-Life Refurbishment	An existing transformer capacity need was identified for DESN #1 (T1/T2) as well as an End-of-Life refurbishment need	Today
Peterborough to Quinte West	Supply Capacity	The load meeting capability of the system is currently exceeded. The outcomes of the Gatineau Corridor End-of-Life Study are forecast to address this need.	Today
Cataraqui TS	Supply Capacity	The autotransformers at Cataraqui is currently forecast to be exceeded.	2023
Port Hope TS	End-of-life	The station transformers at Port Hope TS have been identified as reaching end-of-life in 2025 and requiring replacement.	2025
Frontenac TS	Station Capacity	The transformers at Frontenac TS are forecast to exceed their capability.	2029
Peterborough to Quinte West	Supply Capacity	The load meeting capability of the system is currently exceeded. The outcomes of the Gatineau Corridor End-of-Life Study are forecast to address this need.	2033
Kingston Area	Supply Capacity	The thermal capability of B5QK, which supplies Frontenac TS, is forecast to be exceeded.	2038

7 Plan Options and Recommendations

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

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

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

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

Through this initial screening exercise, it was determined that non-wires alternatives should be assessed for the Frontenac TS capacity need.

7.1 Options for Meeting Near- to Medium-Term Needs

Options for Meeting Station Capacity Needs

Options for Meeting the Belleville TS Station Capacity Need

The options that were considered for Belleville included but were not limited to the following:

1. An addition of a third transformer and station bus at Belleville TS,
2. A new Dual Element Spot Network (DESN) transformer station at Belleville, or
3. Load Transfers

Since Belleville TS does not currently have any distribution load transfer capability, due to a lack of adjacent stations, distribution load transfers were not explored further.

Each of the first two options are estimated to cost approximately \$30-35 M. For a similar cost, option 2 provides more long-term capability and would also perform better under outage conditions.

The high-level cost estimates for wires options are provided by the transmitter, Hydro One. The intention of these high-level (or “planning”) estimates are to enable comparison between options and are typically within an accuracy of +100%/-50%. The Regional Infrastructure Plan (RIP) following the IRRP will perform additional detailed analysis and refine these cost estimates before implementation work begins. The IESO will continue to participate in the Working Group during the RIP and revisit these recommendations if costs estimates differ significantly.

Installing a second DESN at Belleville TS will resolve the need until the end of the planning horizon (20 years). To fully utilize the additional capacity beyond the planning horizon, new supply lines into Belleville would be required. A reinforcement option considered beyond the 20 year planning horizon is to extend X21/X22 (radial lines to Picton/Napanee from Lennox) to Belleville. An initial network study was performed to assess the feasibility of this option and the results of the preliminary study showed that the new station’s capacity can be fully utilized following this reinforcement. However, there might be upstream bulk system impacts with this option, therefore a full bulk planning study is needed to identify any impacts.

Options to Meet the Kingston Area Station Capacity Needs

The Working Group has determined that the limitations of the existing supply to the area poses a risk to accommodating future load growth in the Kingston area. There is a risk that load will materialize sooner than expected as the Working Group is aware of several electrification initiatives on the horizon, identified by both the City and the LDCs for the area. There is also a risk that some of these initiatives may not take place or that they may not have as large an impact as forecast. In either scenario, there is a need for additional capacity at Gardiner TS DESN #1 and Frontenac TS.

Many options and combinations of options were explored by the Working Group and the most relevant ones will be described here.

- Non-wires alternatives: Simple Cycle Gas Turbine (SCGT) generator, Battery Storage
- Distribution load transfers - Permanent load transfers to a station with available capacity
- Increase capacity of the existing station(s) – through asset refurbishment and/or uprates
- A new station (new or existing site)

The capacity at Gardiner TS DESN #1 has already been exceeded today. However, Gardiner TS DESN #2 is adjacent to the station which allows for less complicated load transfers. It is important to note that Gardiner TS DESN #2 is a new transformer station, built in the last 15 years, and has capacity available on the order of 40 MW. The option of load transfers is usually the first avenue pursued as it is preferable to building additional transmission assets.

Hydro One Distribution has identified two load transfer options from Gardiner TS DESN #1 to Gardiner TS DESN #2, each transferring up to 11 MW of load. The first is relatively simple and low in cost while the second load transfer would require a new feeder position, increasing the relative cost.

Hydro One Transmission has identified a replacement plan for Gardiner TS DESN #1 as it is approaching end-of-life. The transformers will be replaced for a like to like replacement with new transformers however, the new transformer units will have a higher LTR and as such, will increase the capacity at the Gardiner TS DESN #1. The simpler 11 MW load transfer, paired with an uprate resulting from a “like-for-like” replacement of the station at Gardiner TS DESN #1, would completely address the reference forecast need over the 20-year planning horizon. With the second 11 MW load transfer the high growth forecast need can be met as well.

Turning to the need at Frontenac TS, the load transfer options available would be to transfer load from Frontenac TS to either Gardiner TS DESN #1 to Gardiner TS DESN #2. Currently, the distribution system in Kingston is operated in such a way that temporary load transfers between stations, ranging from 5 to 20 MW, are regularly utilized as a part of planned and emergency work. Performing a 10 MW load transfer to alleviate the need at Frontenac TS would compromise this flexibility and reduce the reliability of the system. Furthermore, net present value analysis suggests the load transfer would have to delay the need for a new transmission station by at least four years in order for this option to be economically favourable. Therefore, load transfer is an unfavorable option.

This IRRP maintains the long-term flexibility to respond to changes in demand for electricity in the future using cost-effective solutions, such as non-wires alternatives. In particular, smaller scale initiatives could have the potential to cost-effectively defer the need for a conventional solution (i.e. “wires” options), especially when paired with other measures such as energy efficiency. These cost-effective solutions can also be deployed to help delay or reduce large capital investments in transmission and distribution infrastructure. Value is created by delaying the date at which transmission and distribution equipment needs to be expanded, providing optionality. Timing permitting, optionality value allows more time to understand load growth and emerging trends prior to making significant infrastructure investments which reduces the risk of underutilized and/or stranded assets.

The Working Group also examined the feasibility of implementing non-wires resources to reduce the forecast demand in the area and defer the need for a new station or existing station expansion. These potential resources were considered both on an individual basis and as a package of solutions. Figure 7-1 shows that a capacity need exists at all times in the year 2038 at Frontenac station which means the solution will need to address a large scale need.

Figure 7-1 | Need Characterization Heat Map Frontenac 2038

9	0%	0%	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%
8	3%	5%	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%
7	3%	5%	0%	0%	0%	0%	0%	3%	3%	0%	0%	0%
6	3%	10%	0%	0%	0%	0%	0%	3%	8%	0%	0%	0%
5	5%	10%	0%	0%	0%	0%	3%	3%	8%	0%	0%	5%
4	5%	10%	0%	0%	0%	0%	3%	3%	8%	0%	0%	8%
3	8%	13%	0%	0%	0%	0%	3%	3%	13%	0%	0%	10%
2	10%	15%	0%	0%	0%	0%	3%	3%	13%	0%	0%	15%
1	15%	23%	0%	0%	0%	0%	8%	5%	13%	0%	0%	18%
0	15%	25%	0%	0%	0%	0%	10%	5%	20%	0%	0%	25%
MNTH	1	2	3	4	5	6	7	8	9	10	11	12

The analysis for non-wires alternatives identified that an SCGT, battery storage, and energy efficiency as viable solutions for the reference scenario need at Frontenac station. In the year 2038, there is a 10 MW need at Frontenac station under reference forecast, and the station capacity need starts to arise in the year 2029.

Cost estimates for generation and other non-wires alternatives are based on benchmark capital and operating cost characteristics for each resource type and size. Generally speaking, the most cost-effective transmission-connected options for meeting local needs in this region are resources with performance and costs on par with SCGT generators, depending on the relative size of the capacity versus energy requirements. New natural gas-fired generation was considered in the economic analysis for illustrative purposes to represent the cost of new generation. In some cases, battery storage such as lithium nickel manganese cobalt oxide (NMC) batteries are also becoming competitive due to declining technology costs and the expectation of carbon prices increasing in line with federal policy. Other distributed energy resources, which are typically distribution-connected are also considered. The most cost-effective distributed options are typically a combination of smaller-scale storage and demand response. For each of the above options, the system capacity value is “credited” back to arrive at the net cost to meet local reliability needs. This is done to ensure a level playing field comparison between resources that provide capacity and wires options that address the local need but do not provide system capacity benefits.

Both the upfront and operating cost of the wires options, generation, and distributed energy resources are compiled to generate levelized annual capacity costs (\$/kW-yr) over the lifespan of the asset in question for each option. The net present value (NPV) of these levelized costs are the primary basis through which options are compared.

The costs to implement an SCGT (10 MW) is on the order of \$20 M and would defer the need by 10 years, if implemented in 2029. A battery storage solution (10 MW) could defer the need by 10 years as well at an estimated cost of \$7 M¹⁵. After which, a new station is needed. Further, results show that targeted incremental energy efficiency in the area could provide upwards of 15 MW of peak capacity savings by 2030. The costs mentioned here are inclusive of system benefits and present the net value and cost.

To evaluate the combination of these alternatives to delay larger investments, the Working Group considered costs, in terms of NPV. The outcome, in order of highest cost to lowest cost of the combinations are as follows: SCGT [2029] & Station [2038] (\$42M), Station [2029] (\$30M), Battery [2029] and Station [2038] (\$28M). Non-wires solutions for the reference scenario may be useful in addressing the mid-term need and delaying the need for a station, however, barriers exist to both implementation and appropriate allocation of costs to ensure these solutions are cost effective for the local area.

The discussion above only applies to the reference scenario and if a higher growth scenario were to occur then the individual non-wires solutions would no longer be sufficient to meet the need. For the high growth scenarios, the SCGT option was screened out due to high costs. Two different approaches were considered for the high growth scenario in terms of battery solutions: the longest possible deferral of need and the maximised ratio between cost and time of deferral. The order according to cost, from highest to lowest, for combinations of options is: 26 MW Battery [2025] and Station [2032] (\$50M), 10 MW Battery [2025] and Station [2027] (\$43M), and Station [2025] (\$35M).

The Working Group acknowledges that the deferment benefit that a non-wires alternative could provide is highly dependent on how load growth materializes. For the reference forecast, the non-wires alternatives are close in cost to the traditional wires option but if a high growth scenario materializes overall cost would then increase.

¹⁵ After accounting for system benefit achieved by providing support to meet system adequacy/capacity needs

The Working Group next considered some high level review of how a new transformer station should be supplied. In the vicinity, there are two stations – Frontenac TS supplied from the 115 kV system and Gardiner TS supplied from the 230 kV. Frontenac TS is supplied by two 115 kV circuits on separate tower lines. Frontenac TS supplies the Central downtown Kingston area south of Highway 401 as well as the area north of Highway 401 and East of the Cataraqui River. Gardiner TS (DESN #1 & #2) is supplied by the 230 kV system via a double circuit tower line. Gardiner TS supplies the area east of Cataraqui River as well as the area north of Highway 401 and west of the Cataraqui River.

When assessing the options for a new 115 kV supplied station versus a new 230 kV supplied station the analysis showed the 230 kV station to be more favourable for the following reasons. First, in order to build a 115 kV station the two circuits would need to be reinforced in order to meet transmission criteria and ensure load can be supplied during a contingency event. Second, due to upstream constraints on the 115 kV system, it would not be possible to supply the load of an uprated Frontenac TS or a new 115 kV station without considerable upgrades to the Cataraqui autotransformers. Third, building a new 230 kV station in close proximity to the existing 230 kV double circuit tower line may require less additional transmission line work than the 115kV system and also, the 230 kV system can fully supply a new station, without capacity constraints.

The Working Group has confirmed that a new 230 kV station site west of Frontenac TS appears to be the most cost effective option that could help meet the identified needs into the long term, however this option will require Hydro One Distribution to build long feeders to supply customers east of the Cataraqui River. The Working Group has also confirmed that a new 230 kV station east of Frontenac TS would be preferable from a distribution upgrade perspective, however this option has high cost of transmission line extensions within the urban area of Kingston. The Working Group acknowledges that the citing of a new station requires a consideration to balance the cost required to extend 230 kV transmission lines to supply the station versus extending distribution lines required to serve the load. The timing and citing of the station is to be coordinated between the transmitter and the LDCs at which point the trade offs, which could include consideration of how to distribute load between the new and existing stations to manage overall distribution costs, will be considered.

Options for Addressing Supply Capacity Needs

Options for Addressing the Peterborough to Quinte West Supply Capacity Need

The IRRP considered a number of options to address the Peterborough to Quinte West supply capacity need that included and were not limited to the following:

1. Building new transmission supply capacity supplying Dobbin TS
2. Building new transmission supply capacity supplying Sidney TS
3. Siting a new generating resource at Sidney TS

However, this need requires a coordination with the Gatineau Corridor End-of-Life Study to ensure the broader system is considered when reviewing and resolving this need and will be addressed through that study.

Options for Addressing the Cataraqui Autotransformers Supply Capacity Need

The Cataraqui autotransformers have a summer long-term emergency rating of 250 MW. This rating is currently limited by the transformer secondary conductors. A cost effective way to increase the thermal ratings on these autotransformers is to upgrade the transformer secondary conductors, improving the long-term emergency rating without having to upgrade the autotransformers. Upgrading the transformer secondary conductor increases the long-term emergency rating to 285 MW for an estimated cost of \$0.5M.

Non-wires alternatives were screened out at an early stage due to the low cost and low impact of the identified secondary conductor replacement solution. Therefore, this IRRP recommends upgrading the transformer secondary conductors and reassessing whether additional capacity will be required as part of the Lennox to St. Lawrence bulk system study.

End-of-Life Refurbishment Options and Recommendations

Port Hope TS is supplied by the 115 kV system between Dobbin TS and Frontenac TS. Port Hope TS is reaching end-of-life in 2025. Generally, options considered for end-of-life replacements include:

- Replacement of the assets “like-for-like” or with the closest available standard;
- Reconfiguration of the existing assets to “right-size” the replacement option based on: the forecast load growth, changes to the use of the asset since it was originally installed, and reliability or other system benefits that an alternate configuration may provide; or
- Retirement of a facility, considering the impact on load supply and reliability.

Working Group assessments indicated that there are no opportunities for end-of-life optimization at this time and like-for-like replacements with the closest available standard can best address the End-of-Life need at Port Hope TS Recommended Near- to Medium-Term Plan

To address the needs identified, the Working Group recommends the actions described below to meet the near-and medium-term electricity needs of the Peterborough to Kingston region. Successful implementation of these actions, in addition to achievement of existing targeted conservation measures, is expected to address the region’s electricity needs until the late 2020s /early 2030s under the reference forecast.

Build a new 230 kV DESN transformer station at Belleville TS and monitor load growth

To address today’s station capacity need at Belleville TS, as well as serve the growing electricity demand in the region, Elexicon and Hydro One (Transmission) are to initiate the development of a new DESN transformer station at Belleville, with an expected in-service date of 2025. This will increase the supply capacity to the region and will resolve the capacity need at Belleville TS until the end of the planning horizon.

Between planning cycles, the Working Group will continue to monitor the load growth at Belleville TS and re-visit the capacity need in the next regional planning cycle, in order to re-assess whether/when a re-enforcement to Belleville is required. Non-wires alternative such as energy efficiency can delay the implementation, and will be reviewed as part of the next regional planning cycle.

Furthermore, before the next planning cycle, the IESO should assess the bulk system impact of transmission reinforcement to Belleville TS should be included in the scope of a relevant individual bulk planning study for the area.

Hydro One (Distribution) load transfer and advance end-of-life replacement at Gardiner TS DESN #1

To address the near-term capacity need at Gardiner TS DESN #1, Hydro One (Distribution) will complete a relatively low cost and low lead-time load transfer of 11 MW between Gardiner TS DESN #1 and Gardiner TS DESN #2 by 2022 as a first step.

In addition, Hydro One will explore advancing the end-of-life replacement of Gardiner TS DESN #1 transformers to increase the station capacity. Advancing the replacement date, combined with the load transfer, will address the Gardiner TS DESN #1 capacity need for the duration of the planning horizon for the reference load forecast.

The Working Group will continue to monitor load growth in the area to evaluate if a second 11 MW load transfer to Gardiner TS DESN #2 is required.

Monitor load growth and initiate development and siting work to build a new 230 kV DESN transformer station in Kingston when needed

Building a new 230 kV station in Kingston, supplied by 230 kV circuits X2H and X4H, will address the local need for station capacity at both Frontenac TS and Gardiner TS over the long term and for multiple growth scenarios. Due to the uncertainty in the forecast, the timing of the need for the new station could be in the near to medium term, as late as 2029. Hence, Hydro One Distribution and Utilities Kingston will work together to monitor the load growth in the area, and trigger the development work, and ultimately the construction, of a new 230 kV supply station when there is sufficient certainty in the timing of new demand materializing.

Address implementation and cost allocation barriers to cost-effectively deploying non-wires alternatives to defer needs

The development of a non-wire alternative, specifically additional energy efficiency or a local storage solution, could defer the new station ultimately required to accommodate load growth in the City of Kingston. This is cost-effective, under the reference load growth scenario, if cost-allocation can reflect the system benefits the non-wires alternative would provide. Additional barriers to implementation also exist around who would implement the solution and how they would seek cost-recovery, particularly if both benefiting LDCs were to implement a part of the solution. The IESO will work with impacted LDCs between regional planning cycles to address these barriers to implementation and cost allocation for a non-wires alternative, in tandem with developing plans for a new transformer station.

Complete the ongoing Gatineau Corridor End-of-Life Study and implement recommendations

The outcomes of the Gatineau Corridor End-of-Life Study will improve the supply capability in the Peterborough to Kingston region. Namely, addressing the identified supply capacity need to Peterborough and Quinte West. By implementing the recommendations of the Gatineau Corridor End-of-Life study this need should be addressed.

Upgrade Cataraqui autotransformers' secondary conductors and reassess as part of the Lennox to St. Lawrence bulk system study

Upgrading the autotransformers' secondary conductors will increase the thermal capacity of these autotransformers from 250 MW to 285 MW and will resolve the thermal violation after losing one of the autotransformers. A future Lennox to St. Lawrence bulk system study will reassess the need with this solution in place and study if additional capacity is required.

Replace Port Hope TS T3/T4 with the closest available standard size transformers

Port Hope TS T3/T4 are reaching end-of-life and there are no opportunities for end-of-life optimization at this time. This IRRP recommends like-for-like replacements with the closest available standard size transformers of equal or greater capacity.

7.2 Options for Meeting Long-Term Needs

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

Option for Meeting Supply Capacity Needs

Options for Meeting the Peterborough to Quinte West Supply Capacity Needs

Similar to the Cataraqui autotransformers need, the Peterborough to Quinte West pocket voltage need relates to the Peterborough to Quinte West supply need where it is expected that any reinforcement made to the Peterborough to Quinte West area supply, such as those contemplated in the Gatineau Corridor End-of-Life Study, will naturally resolve the under voltage violations observed in this pocket.

Options for Meeting the Kingston Transmission Supply Capacity Needs

Since this need starts to substantiate beyond the planning horizon following the reference forecast, early development work for a transmission line upgrade is not required at this time.

There may be opportunities for the Working Group to work with communities and local utilities to manage future electricity demand through the development of community-based solutions under the IESO's new CDM Framework or other mechanisms or opportunities that may evolve between planning cycles.

7.3 Recommended Long-Term Plan

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

The recommended actions for the long-term plan are outlined below.

Monitor the Peterborough to Quinte West 115 kV system voltage performance following the recommendations of the Gatineau Corridor End-of-Life Study

Low voltage violations are observed in the long-term planning horizon in the Peterborough to Quinte West 115 kV pocket. These violations may naturally be resolved by the outcome of the Gatineau Corridor End-of-Life Study; therefore, this need will be monitored and re-assessed following the Gatineau Corridor End-of-Life Study plan during the next planning cycle.

Monitor Kingston Area Transmission Supply Capacity Needs

The IESO should re-evaluate the capacity need on B5QK periodically and explore non-wire solutions with the Working Group and communities as appropriate.

Monitor demand growth, conservation achievement and distributed generation uptake

On an annual basis, the IESO, with the Working Group, will review CDM achievement, the uptake of provincial distributed generation (DG) projects, and actual demand growth in the Peterborough to Kingston Region. This information will be used to determine when decisions on the long-term plan are required, and to inform the next cycle of regional planning for the area. Information on CDM and DG is also a useful input into the ongoing development of non-wires alternatives as potential long-term solutions.

Initiate the next regional planning cycle early, if needed

Along with the indices outlined above, the Working Group will monitor changes in growth targets, progress in electrification in the region, and any significant changes in forecast growth. If monitoring activities determine that the region’s growth is exceeding the load forecast (the high demand forecast in Belleville and Kingston, or the reference demand forecast in the remainder of the region), it may be necessary to initiate the next iteration of the regional planning process earlier than 2024 given the lead time for the long-term supply options.

7.4 Summary of Recommended Actions and Next Steps

Table 7-1, below, summarizes the specific recommendations that should be implemented immediately to address the most imminent electricity supply needs in the Peterborough to Kingston region.

Table 7-1 | Summary of 2021 Peterborough to Kingston IRRP Recommendations

Need	Recommendation	Lead Responsibility	Estimated Cost	Timeline
Belleville Station Capacity	Build a new Dual Element Spot Network (DESN) transformer station at Belleville	Elexicon and Hydro One Transmission	~\$30-35M	Beginning in 2021
Kingston Area Station Capacity – Frontenac TS	Monitor load and trigger development work, and ultimately construction, for a new 230 kV transformer station, when required. Continue development of energy efficiency programs for the area	Utilities Kingston, Hydro One Distribution, Hydro One Transmission IESO	~\$30-35M	Station needed between 2025 and 2029 depending on forecast scenario.
Kingston Area Station Capacity – Gardiner TS DESN #1	Perform permanent 11 MW load transfer to Gardiner TS DESN #2. Hydro One transmission to perform end-of-life refurbishment of the station, thereby increasing LTR. LDCs to monitor load and evaluate the second 11 MW load transfer, if required, as it has a high cost (\$5.5M), which is not included in the estimate).	Hydro One Distribution, Hydro One Transmission	~\$0.5M	First Load transfer: 2022 Refurbishment: as soon as possible (2024-2025) Second Load Transfer: explore it, if required
Port Hope TS	Replace Port Hope TS T3/T4 with the closest available standard size transformers	Hydro One Transmission	Cost of refurbishment incurred by Hydro One Transmission	Beginning in 2025
Cataraqui Autos Supply Capacity	Upgrade Cataraqui Autotransformers' secondary conductors	Hydro One Transmission	~\$0.5M	Early 2024

The Working Group has also identified the following additional planning activities to address ongoing regional planning needs

Need	Recommendation	Lead Responsibility	Timeline
Peterborough to Quinte West Area	Complete the ongoing Gatineau Corridor End-of-Life Study and implement recommendations	IESO	Early 2022
Cataraqui Autos Supply Capacity	Following the conductor upgrade, review this need in further detail as part of Lennox to St. Lawrence bulk study.	IESO	2023

8 Engagement

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

8.1 Engagement Principles

The IESO's engagement principles¹⁶ help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 8-1 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for Peterborough to Kingston

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

- Discussions to help inform the engagement approach for the planning cycle;
- Communications and other engagement tactics to enable a broad participation, using multiple channels to reach audiences; and

¹⁶ <https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles>

- Identifying specific stakeholders and communities who may have a direct impact on this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region

As a result, the engagement plan¹⁷ for this IRRP included:

- A dedicated webpage¹⁸ on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities, rights-holders and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars;
- Web-conferencing meetings; and
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (see Section 8.4 Bringing Municipalities to the Table).

8.3 Engage Early and Often

Early communication and engagement activities began with invitations to all subscribers, municipalities, Indigenous communities and rights-holders in the Peterborough to Kingston Region to learn about and provide comments on the draft Scoping Assessment Outcome Report. The IESO also held preliminary discussions to help inform the engagement approach for this first active cycle of formal regional planning. This started with an invitation to targeted municipalities, Indigenous communities, rights-holders and those with an identified interest in regional issues to help inform the engagement approach and learn more about how to provide comments on the Peterborough to Kingston Scoping Assessment Report before it was finalized.

Feedback was received and focused on the need to consider local economic development and impacts to service when undertaking planning activities as part of implementation of recommended work. Feedback in early discussions also emphasized the importance of aligning community energy and climate action plans, electrification targets and other planning initiatives in the development of the IRRP. Along with a response to the feedback received, the final Scoping Assessment was posted in May 2020 which identified the need for a coordinated regional planning approach done through an IRRP for the Peterborough to Kingston Region. The final Scoping Assessment, identified the need for an IRRP for the Peterborough to Kingston Region. Following a written comment window, the final Scoping Assessment Outcome Report was published in May 2020.

¹⁷ <https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/KWCG-Region/KWCG-Engagement-Plan.ashx>

¹⁸ <https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Integrated-Regional-Resource-Plan-Kitchener-Waterloo-Cambridge-Guelph>

Outreach then began with targeted communities to inform early discussions for the development of the IRRP including the IESO's approach to engagement. The launch of a broader engagement initiative followed with an invitation to subscribers of the Peterborough to Kingston region to ensure that all interested parties were made aware of this opportunity for input. Three public webinars were held at critical stages during the IRRP development to give interested parties an opportunity to hear about progress and provide comments on key components of the plan. All webinars received strong participation with cross-representation of stakeholders and community representatives attending the webinar, and submitting written feedback during a 21-day comment period.

The three stages of engagement invited input on:

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

Comments received during this engagement focused on the following major themes:

- Consideration should be given to local developments and growth plans
- Alignment and coordination is needed with other community planning and projects in the region. Future infrastructure and/or electricity supply should consider the priorities of energy and climate action plans and, in particular, plans for fuel switching in the municipal, commercial and residential sector, as well as vehicle electrification
- Incorporate shifting economies into planning assumptions and cost benefit analysis
- Integrated options that provide both local and broader provincial system benefit should be considered
- Recommendations for the near and mid term should be based on a high demand growth scenario, and provide flexibility for the long term should additional increased demand materialize as a result of electrification plans

Feedback received during the written comment periods for these webinars helped to guide further discussion throughout the development of this IRRP as well as add due consideration to the final recommendations. This includes using a high-demand forecast scenario to shape the development of the IRRP as a result of community feedback on local plans for electrification.

All interested parties were kept informed throughout this engagement initiative via email to Peterborough to Kingston region subscribers, municipalities and communities as well as the members of the East Regional Electricity Network.

Based on the discussions both through the Peterborough to Kingston IRRP engagement initiative and broader network dialogue, it is clear that there is broad interest in several East Ontario communities to further discuss the potential for alternative energy solutions. The near- to medium-term nature of the Peterborough to Kingston region's future electricity needs presents a valuable opportunity for communities to mobilize projects and initiatives to meet local growth targets and energy priorities. To that end, ongoing discussions will continue through the IESO's East Regional Electricity Network to keep interested parties engaged on local developments, priorities and planning initiatives.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Peterborough to Kingston IRRP engagement [web page](#).

8.4 Bringing Municipalities to the Table

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

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities and rights-holders within the Peterborough to Kingston electricity planning region throughout the development of the plan. This includes the communities of Alderville First Nation, Hiawatha First Nation, Curve Lake First Nation, Mohawks of the Bay of Quinte, Tyendinaga Mohawk, Kawartha Nishnawbe and the traditional territory of the Huron Wendat.

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



9 Conclusion

This report documents an IRRP that has been developed for the Peterborough to Kingston region, and identifies regional electricity needs and opportunities to preserve or enhance electricity system reliability for the next 20 years. The IRRP makes recommendations to address near- to medium-term issues, and lays out actions to monitor, defer, and address long-term needs.

To support the development of the plan, this IRRP includes recommendations with respect to developing alternatives, and monitoring load growth and efficiency achievements. Responsibility for these actions will be undertaken by the appropriate members of the Working Group.

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

**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](https://twitter.com/IESO_Tweets)

 facebook.com/OntarioIESO

 linkedin.com/company/IESO