BY EMAIL AND RESS

September 11, 2026

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

Hydro One Networks Inc.
483 Bay Street
7th Floor South Tower
Toronto, Ontario M5G 2P5
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Pasquale Catalano
Director
Infrastructure, Partnerships and Compliance
C 647.616.8310
Pasquale.Catalano@HydroOne.com

Dear Mr. Murray,

EB-2026-0207 – Hydro One Networks Inc. Leave to Construct Application – K1/K2 Refurbishment 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 in the Kirkland Lake area of northeastern Ontario.

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

Hydro One is confirming that the documents filed in support of the referenced application do not include any personal information under the Freedom of Information and Protection of Privacy Act (Ontario) ("FIPPA") with respect to this Application. Any FIPPA related information in the Application has been redacted. Consistent with Section 10 of the OEB's Practice Direction, the personal information contained at Attachment 3 of Exhibit E, Tab 1, Schedule 1 is also redacted as the information about an identifiable individual that may be of a personal nature.

Furthermore, Hydro One is confirming that the System Impact Assessment report appendices, which contain confidential information and if disclosed could reasonably be expected to pose a potential security threat to the integrated power system, have been omitted from this Application. This information is contained at Attachment 1 of Exhibit F, Tab 1, Schedule 1. This approach is consistent with the OEB's Chapter 4 Filing Requirements.[1]

Likewise, Appendix 1 of the Customer Impact Assessment filed as Attachment 1 of Exhibit G, Tab 1, Schedule 1, has been redacted. This information has been considered to be presumptively confidential, consistent with Appendix B of the OEB's Practice Direction on Confidential Filings[2] on the basis that it is information that would disclose load profiles, energy usage and billing information of a specific customer that is not personal information.

[1] OEB Chapter 4 Filing Requirements – Issued December 16, 2025 – Section 4.3.6.
[2] Last Revised on December 17, 2021.

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

Sincerely,



Pasquale Catalano

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EXHIBIT LIST

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LIST OF ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	Acronym or Abbreviation Expansion
A	Amperes
AACE	Association for the Advancement of Cost Engineering *(estimate classification system)*
AC/DC	Alternating Current / Direct Current
ACSR	Aluminium-Conductor Steel-Reinforced cable
ACSR/TW	Aluminium-Conductor Steel-Reinforced, trapezoidal shaped cable
AFUDC	Allowance for Funds Used During Construction
Agnico Eagle	Agnico Eagle Mines Ltd.
C	Celsius
CIA	Customer Impact Assessment
Class EA	Class Environmental Assessment
CSA	Canadian Standards Association
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
EA	Environmental Assessment
EPC	Engineering, Procurement and Construction
ESR	Environmental Study Report
Hydro One *(HONI)*	Hydro One Networks Inc.
IEP	Integrated Energy Plan (June 2025)
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
ISD	Investment Summary Document
ISOC	Integrated System Operating Center
JCT	Junction
JRAP	Joint Rate Application
kcmil	Kilo-circular mils *(unit of measure of the area of a wire with a circular cross section)*
KLPC	Kirkland Lake Power Corp
km	Kilometer
kV	Kilovolt
kW	Kilowatt
LTE	Long Term Emergency rating
m	Meter

Acronym or Abbreviation	Acronym or Abbreviation Expansion
MECP	Ministry of the Environment, Conservation and Parks
MTS	Municipal Transformer Station
MVA	Megavolt-ampere
MW	Megawatt
MWHR *(or MWH)*	Megawatt-hour
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NPV	Net Present Value
OEB	Ontario Energy Board (the Board)
OMA	Operations, Maintenance and Administrative costs
OPGW	Optical Ground Wire
PV	Present Value
ROE	Return on Equity
ROW	Right-of-Way
RPP	Regulated Price Plan
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
TSP	Transmission System Plan
UTR	Uniform Transmission Rates

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Hydro One Networks Inc. ("**Hydro One**") pursuant to s. 92 of Act for an Order or Orders granting leave to construct transmission line facilities in the Kirkland Lake area of northeastern Ontario.

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

APPLICATION FOR LEAVE TO CONSTRUCT

SEPTEMBER 11, 2026

A. INTRODUCTION

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

2. Hydro One hereby applies to the Ontario Energy Board ("OEB" or "Board") pursuant to s. 92 of the Act for an Order or Orders granting leave to refurbish portions of an existing 115 kV transmission circuit (nomenclature "K2") and remove the remaining components of an adjacent idle 115 kV transmission circuit (nomenclature "K1") in the Kirkland Lake area of northeastern Ontario, referred to herein as the "Project" or "K1/K2 Refurbishment Project".

3. The total length of the Project's transmission line is approximately 13.7 kilometers, all of which is on privately owned lands. The Project is sited within a varying corridor width, ranging between approximately 30 – 46 metres.

4. Hydro One currently holds approximately 67% of the privately held land rights required along the route. As part of the project Hydro One requires new rights on 6 properties, 4 of which have already come to an agreement with Hydro One. Hydro One is seeking approval from the OEB of the form of the voluntary property rights agreements offered or to be offered to affected landowners, pursuant to s. 97 of the Act.

5. The refurbishment of the K2 circuit is required because the existing facilities have reached end of life. Hydro One is undertaking the Project at this time to take advantage of a limited construction window (driven by outage availability on the circuit) primarily driven by the connected customer on the circuit, a gold mine, entering a reduced electricity demand phase commonly referred to as a 'care and maintenance' period. Completing the work during this period is expected to allow

Hydro One to execute the Project more effectively and efficiently, while reducing the operational impacts that would otherwise arise if the circuit were carrying higher customer load.

B. NATURE OF THE PROJECT

6. Circuit K1 was constructed in parallel with K2 but is no longer in operation. While portions of the K1 circuit have previously been removed, approximately 1.4 km of conductor remains in place between Kirkland Lake TS and Gull Lake North Junction ("JCT"). Circuit K2 is a 13.7 km, 115 kV, single circuit transmission line that connects Kirkland Lake TS and American Barrick JCT. Circuit K2 provides electrical connection to Kirkland Lake Power Corporation (“KLPC”) and Agnico Eagle Mines Ltd. (“Agnico Eagle”).

7. The northern segment of the K2 line, between American Barrick Junction and Holloway Holt Junction, was constructed in 1948. Condition assessment data for this section does not present evidence for a sustainment need at this time, and in alignment with Hydro One’s condition-based asset management strategy, it will not be refurbished at this time. Hydro One proposes to utilize temporary generation at the Agnico Eagle site while Circuit K2 is out of service. Based on an assessment of alternative supply options, temporary generation was determined to be the most cost-effective approach for maintaining service to Agnico Eagle during the outage, particularly given the reduced electricity demand expected during the mine's planned care-and-maintenance period.

8. The Project is consistent with the recommendations made by the Independent Electricity System Operator (“IESO”) in the North/East Sudbury Integrated Regional Resource Plan (“IRRP”) and Regional Infrastructure Plan (“RIP”). Copies of the IRRP and RIP can be found at Attachments to **Exhibit H, Tab 1, Schedule 1.** The IESO has also provided correspondence to address whether the Project has linkages and/or interdependencies to regional plans and/or IESO bulk plans. A copy of the

correspondence is included at **Exhibit B, Tab 3, Schedule 1, Attachment 1**. The Project has been identified as a discretionary sustainment project, as further described in **Exhibit B, Tab 4, Schedule 1**.

9. The 115 kV 411 kcmil ACSR/TW conductor selected by Hydro One to construct the new transmission line is 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**.

10. A copy of an overview map of the Project area is provided in **Exhibit B, Tab 2, Schedule 1, Attachment 1,** and a copy of a schematic diagram of the Project can be found at **Exhibit B, Tab 2, Schedule 1, Attachment 2.**

11. The proposed in-service date for the Project is October 31, 2027. This forecast in-service date is predicated on an assumed construction commencement date of March 2027. To support this construction commencement date, Hydro One requests OEB approval of the Project prior to the end of February 2027. A copy of the Project schedule is provided at **Exhibit B, Tab 11, Schedule 1**.

12. The IESO has completed a final SIA for the Project. The final 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. A copy of the IESO's final SIA is provided at **Exhibit F, Tab 1, Schedule 1, Attachment 1**.

13. Hydro One has completed a final CIA in accordance with Hydro One's connection procedures. A copy of the final CIA is provided at **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.

14. The forecast total capital cost of the Project is $26.3 million[1]. Details pertaining to these costs are provided at **Exhibit B, Tab 7, Schedule 1**. The corresponding 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 $0.02/month (or 0.01%) increase on a typical residential customer's bill under RPP.

C. PROJECT LAND REQUIREMENTS

15. Six privately held permanent land rights on the proposed route are required to deliver the Project. Temporary rights for construction purposes may be required along the corridor and these rights will be negotiated and acquired as and when needed. Hydro One met with affected property owners since March 2025 regarding Hydro One's voluntary land acquisition process. As of September 2026, four voluntary property settlement offers pertaining to privately held lands had been accepted by affected landowners. Further information regarding the real estate needs to complete this Project are provided in **Exhibit E, Tab 1, Schedule 1**.

16. Hydro One seeks approval of the form of the voluntary property rights agreements offered or to be offered to affected landowners, pursuant to s. 97 of the Act. The agreements are in the same form as previously approved in prior Hydro One's leave to construct proceedings. During property acquisition discussions, affected landowners were advised by Hydro One that they have the option to receive independent legal advice and that Hydro One is committed to reimbursing affected landowners for reasonably incurred legal fees associated with the review and execution of the necessary land rights agreements. The form of the agreements for which approval is sought is found at attachments to **Exhibit E, Tab 1, Schedule 1**.

17. Hydro One consents to the conditions outlined in the OEB's standard conditions of approval for electricity transmission leave to construct applications[2] for this Project.

[1] An additional $2.1M of OM&A removal costs are associated with completing this Project.
[2] https://www.oeb.ca/sites/default/files/issues-list-LTC-electricity.pdf

D. PUBLIC INTEREST

18. The Project is being undertaken to address the reliability needs of the transmission system due to aging facilities. The Project meets the needs of the transmission system and connected customers in the local area as the renewed assets can be expected to maintain or improve the quality of service and reliability of the circuit.

19. The Project has considered transmission line losses in a cost-effective manner. There are no practical alternatives to the Project scope of work. Further information regarding the cost benefit analysis of the Project is provided in **Exhibit B, Tab 5, Schedule 1**.

20. As documented in the Final CIA[3], no directly connected customers are adversely affected by the Project. The Project concords with the commitments undertaken through the Class EA process. The IESO's Final SIA[4] confirms that the Project will have no material adverse impact on the reliability of the integrated power system.

21. Overall, the Project is not expected to have a material impact on Uniform Transmission Rates or the overall average Ontario consumer's electricity bill.

E. REQUESTED RELIEF

22. Hydro One requests:
    a) An Order or Orders made pursuant to section 92 of the Act granting leave to construct the Project;
    b) An approval of the form of the voluntary property rights agreements offered or to be offered to affected landowners, pursuant to s. 97 of the Act, and
    c) Such other relief as Hydro One may request or as the Board may direct.

[3] Exhibit G, Tab 1, Schedule 1, Attachment 1.
[4] Exhibit F, Tab 1, Schedule 1, Attachment 1.

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

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

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

a) The Applicant:

Ms. Eryn Mackinnon
Regulatory Advisor
Hydro One Networks Inc.

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

b) The Applicant's Counsel:

Mr. Richard J. King / Mr. Alex Farrant
Osler, Hoskin & Harcourt LLP

Mailing Address:	Suite 6200, First Canadian Place
	100 King Street West
	Toronto, Ontario M5H 1H1
Telephone:	(416) 862-6626 / (416) 862-4216
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Electronic access: rking@osler.com / afarrant@osler.com

c) The Applicant's counsel:

Laura Brazil
Assistant General Counsel
Hydro One Networks Inc.

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Toronto, Ontario M5G 2P5
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PROJECT OVERVIEW DOCUMENTS

Hydro One is seeking approval to refurbish portions of an existing 115 kV transmission circuit (nomenclature 'K2') and remove the remaining components of an adjacent idle 115 kV transmission circuit (nomenclature 'K1') in the Kirkland Lake area of northeastern Ontario. Circuits K1 and K2 originate from Kirkland Lake TS and were originally placed in service in 1927. Circuit K2 provides electrical supply to two customers: KLPC and Agnico Eagle.

Circuit K1 was constructed in parallel with the K2 circuit, however, K1 is no longer in operation. While portions of the K1 circuit have been removed previously, approximately 1.4 km of conductor remains in place between Kirkland Lake TS and Gull Lake North JCT. The condition of both circuit facilities are poor. This has elevated the circuits' safety, reliability, and maintenance risks. The Project is therefore necessary to continue to provide reliable service to the connected customers and mitigate risks associated with deteriorated and obsolete infrastructure.

The proposed Project consists of the refurbishment of approximately 13.7 km of the existing 115 kV K2 transmission circuit between Kirkland Lake TS and American Barrick JCT. Refurbishment activities include the replacement of deteriorated conductor, replacement of deteriorated structures, and the implementation of associated structural reinforcements and renewals required to sustain reliable operation and ensure compliance with current engineering and operating standards. The Project also includes the removal of the remaining conductor associated with the idle K1 circuit between Kirkland Lake TS and Gull Lake North JCT to reduce safety risks posed by obsolete infrastructure and improve overall corridor safety.

Notable to the execution delivery of the Project, KLPC is also connected to circuit D3K, where three of its six generators are connected to circuit K2 and the balance to circuit D3K via Dymond TS. As such, outages on circuit K2 between Kirkland Lake TS and Gull Lake North JCT will only impact half of KLPC's generators. Circuit K2 outages between Gull

Lake North JCT and American Barrick JCT, will not impact KLPC. In contrast, Agnico Eagle is connected downstream of American Barrick JCT, where all outages for the proposed project will be impactful. Accordingly, the necessary refurbishment requires a construction strategy and solution that maintains service continuity during any planned outage period to Agnico Eagle. Cognizant of this constraint, Hydro One is attempting to maximize on a period of 'care and maintenance' for Agnico Eagle, effectively meaning that the customer's electrical load demand is low compared to what it would be during their normal operating profile. The Project's execution schedule, provided at Exhibit B, Tab 11, Schedule 1, has been developed with the aim of reducing the impact to the customer, and reduce the overall cost of providing alterative supply during the K2 circuit's outage. Based on an assessment of alternative supply options for Agnico Eagle while the K2 circuit is out of service, temporary on-site generation was determined to be the most cost-effective approach for maintaining service to Agnico Eagle.

The outage on the K2 circuit will be scheduled and managed in coordination with the customers to align over the outage period(s). Additional information on the evaluation of supply alternatives and the selection of temporary generation is provided in **Exhibit B, Tab 7, Schedule 1.**

A map showing the geographic location of the existing facilities and the proposed relocation route are provided in **Exhibit B, Tab 2, Schedule 1, Attachment 1.** Schematic diagrams of the transmission line facilities are provided at **Exhibit B, Tab 2, Schedule 1, Attachment 2.**

The K1/K2 Refurbishment Project will deliver the following benefits:

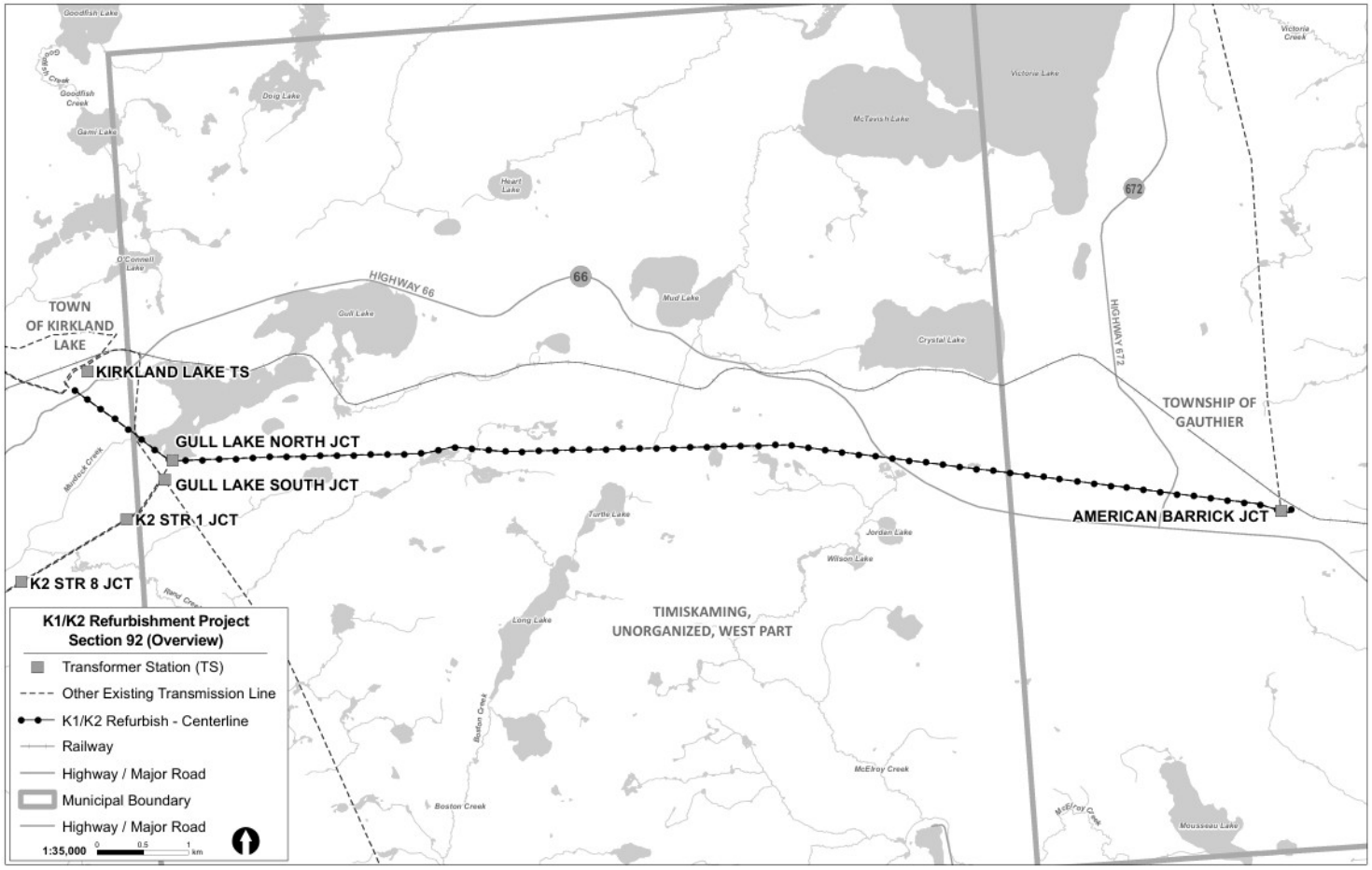
- Maintain reliable electrical service to customers in the Kirkland Lake area connected to the K2 circuit through the replacement and refurbishment of obsolete and deteriorated transmission infrastructure.
- Enhance public and worker safety while improving transmission corridor reliability and maintainability by removing the remaining conductor and associated equipment of the idle K1 circuit.

- Support Hydro One's commitment to customers by improving system reliability, reducing line losses and future maintenance requirements, and ensuring compliance with current engineering, safety, and operating standards.

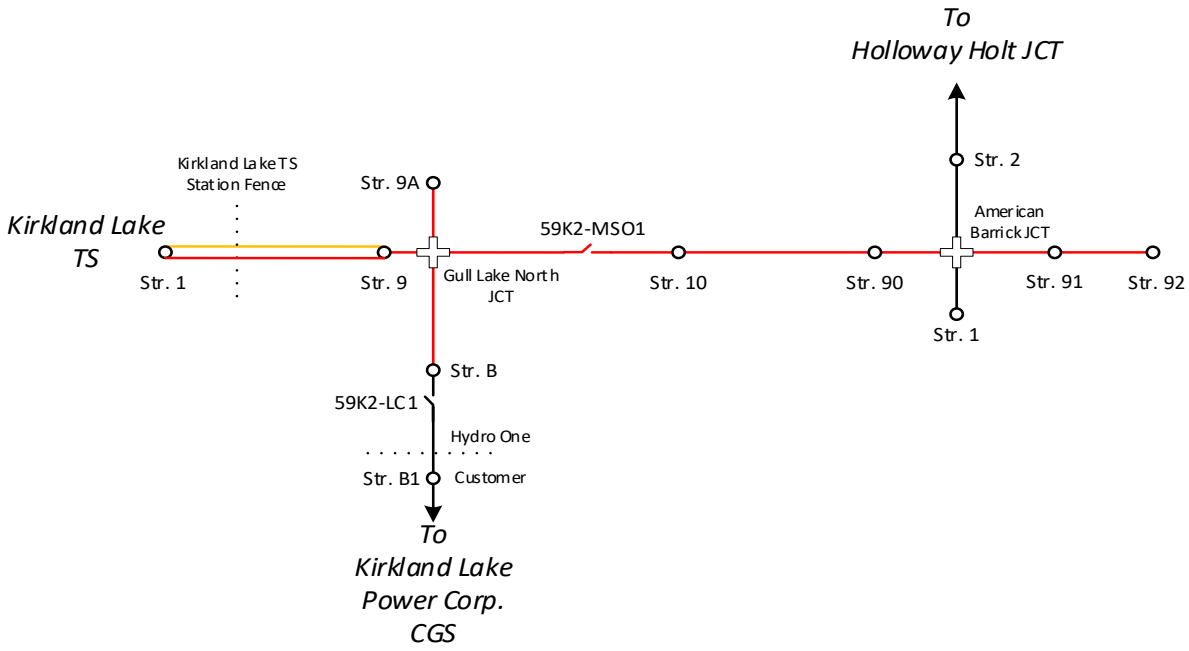
Completion of the Project will enhance the long-term safety, reliability, and sustainability of the transmission facilities serving customers in the Kirkland Lake area by renewing obsolete and deteriorated infrastructure and mitigating identified asset risks.

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GENERAL AREA MAP



REFURBISHMENT OF EXISTING FACILITY:
115 kV CIRCUIT K2, KIRKLAND LAKE TS X AMERICAN BARRICK JCT
LINE SCHEMATIC DIAGRAM



Legend

- Segments of transmission circuit K2 refurbished (13.7 km)
- Segments of transmission circuit K2 not touched
- Idle transmission circuit K1 to be removed (1.4 km)
- Junction (JCT)
- Line Sectionalizing Device

EVIDENCE IN SUPPORT OF NEED

Hydro One's transmission **circuits K1 and K2 are part of the North/East of Sudbury region.** Circuits K1 and K2 are **radial lines and** do not form part of **network system facilities**. As such the IESO has not considered these circuits, or the specific sections being addressed by the Project, in any Bulk System Plans, however, the need for this refurbishment work has been outlined in the latest IRRP[1] and RIP[2], which are provided at **Exhibit H, Tab 1, Schedule 1, Attachments 1 and 2**.

The Project is driven by the need to refurbish the sections of the K2 circuit. No additional supply needs have been identified from a network perspective. Hydro One engaged the existing connected customers on the circuit to understand their future requirements and to provide an opportunity for them to identify any need for additional capacity on the line. No additional customer needs were identified. Accordingly, based on current capacity conditions on the K2 circuit, Hydro One has determined that refurbishment using its minimum standard transmission line conductor for a 115 kV transmission line (i.e., 411 kcmil ACSR), will be sufficient to meet customer supply requirements and ampacity needs going forward.

Further, refurbishment of K2, which will return this transmission facility to like-new condition, and the removal of the remaining components of the idle K1 circuit, the Project will reduce the present safety and reliability risks associated with operating and maintaining poor condition assets between Kirkland Lake TS and American Barrick JCT.

Further to the above information, the IESO has provided a letter to Hydro One dated July 27, 2026, ("the Letter") which addresses whether the Project has linkages and/or interdependencies to regional plans and/or IESO bulk plans which is included at **Attachment 1** to this Exhibit. The Letter aligns with the findings of the IESO's regional

[1] North & East of Sudbury: Integrated Regional Resource Plan, Section 7.2.2, page 37
[2] North & East of Sudbury – Regional Infrastructure Plan, Section 9, page 10

planning for the North/East Sudbury Region[3] issued in April 2023 that the Project is required to ensure continued safe and reliable supply for this region. The Letter supports the proposed scope of work and confirms the IESO is also not aware of, and has not identified, any additional system needs or additional load supply requirements in the area that might impact the Project.

[3] Exhibit H, Tab 1, Schedule 1, Attachment 1.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, ON M5H 1T1
t 416.967.7474
www.ieso.ca

July 27, 2026

Pasquale Catalano
Director, Major Projects and Partnerships
Hydro One Networks Inc.
483 Bay Street,
Toronto, ON, M5G 2P5

Dear Mr. Catalano:

Re: Supplemental Support of Need – K1/K2 115 kV Transmission Circuit Refurbishment Project

The Independent Electricity System Operator ("IESO") is providing this letter in response to Hydro One Networks Inc.'s ("Hydro One") request for supplemental planning support regarding the K1/K2 115 kV Transmission Circuit Refurbishment Project, which Hydro One intends to include as supporting information in its application under section 92 of the *Ontario Energy Board Act, 1998*.

Background

The proposed project consists of:

- refurbishing approximately 13.7 km of the existing K2 115 kV transmission circuit between Kirkland Lake Transformer Station ("TS") and American Barrick Junction; and
- decommissioning the remaining K1 transmission line infrastructure between Kirkland Lake TS and Gull Lake North Junction through the removal of remaining line conductor and hardware.

Based on the information provided by Hydro One, the project is intended to address the condition of aging transmission assets, improve operational reliability, reduce safety risks associated with deteriorated infrastructure, and facilitate continued maintenance of the transmission system.

The IESO reviewed previous planning materials for the area and notes that, while no explicit bulk system need was identified requiring this specific refurbishment, the 2023 Integrated Regional Resource Plan (IRRP) contemplated that transmission asset renewals would proceed, as required, to maintain reliable electricity service within the region. Accordingly, the proposed work is not inconsistent with those planning assumptions.

IESO Assessment

The IESO considers the proposed work to be an end-of-life transmission asset renewal project rather than a project driven by new bulk electricity system needs.

The IESO further notes that the project:

- is intended to support the continued reliable operation of the existing transmission system;
- addresses aging transmission infrastructure through refurbishment and selective decommissioning of obsolete facilities; and
- does not have any material interdependencies with the North of Sudbury Bulk Plan or associated bulk transmission planning initiatives.

Conclusion

The IESO has no planning concerns and supports Hydro One proceeding with the proposed K1/K2 Transmission Circuit Refurbishment Project as described above.

Please let me know if Hydro One requires any additional information regarding the IESO's assessment.

Sincerely,



Gabriel Adam, P.Eng
Director, Transmission Assurance and Standards
IESO

cc: Alessia Dawes, Hydro One
Kennan Ip, IESO
Beverly Nollert, IESO

PROJECT CATEGORIZATION AND CLASSIFICATION

PROJECT CATEGORIZATION

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

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

Based upon the above criteria, Hydro One submits that the Project is properly categorized as a discretionary project as it is work triggered by the need for circuit refurbishment given the current facilities approaching their end of life**.** The Project will return the K2 transmission 115 kV circuit section to 'as-new' condition, increasing the lines reliability, quality and safety in the local area.

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 5 of the OEB Filing Requirements for Utility System Plans, are those which:
  i. provide an adequate supply capacity and/or maintain an acceptable or prescribed level of customer or system reliability for load growth or for meeting increased stresses on the system; or
  ii. enhance system efficiency such as minimizing congestion on the transmission system and reducing system losses.
- Connection Projects, which most closely align with the System Access category as defined in Chapter 5 of the OEB Filing Requirements for Utility System Plans, are those which provide connection of a load or generation customer or group of customers to the transmission system.
- Sustainment Projects, which most closely align with the System Renewal category as defined in Chapter 5 of the OEB Filing Requirements for Utility System Plans, are those which maintain the performance of the transmission network at its current standard or replace end-of-life facilities on a “like for like” basis.

Based on the above criteria, the Project is a Sustainment Project as the proposed transmission facilities provide for the need to refurbish existing assets given their age and poor condition and to maintain system capacity, reliability and quality of electricity supply.

Categorization and Classification

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

COST BENEFIT ANALYSIS AND OPTIONS

Hydro One considered meeting this sustainment through building the K2 via a new, greenfield, right-of-way. This option would require materially more land right acquisitions, environmental assessment work and would not utilize the existing facility's longer life composite structures which are expected to have decades of remaining life. For this reason, this option was rejected. There were no other practical alternatives to the K1/K2 Refurbishment Project.

Hydro One also considered deferring the refurbishment work. However, deferral would extend reliance on aging infrastructure and could result in the loss of a planned outage opportunity required to efficiently complete the work. Based on the condition of the existing facilities, the associated reliability risks, and the availability of the customer outage window, proceeding with the refurbishment at this time was determined to be the preferred option.

1.0 TRANSMISSION LINE ALTERNATIVES

Conductor Size Alternative Analysis

Hydro One undertook an analysis of conductor size alternatives that would: (a) meet the supply needs outlined the North/East of Sudbury IRRP and RIP as identified at **Exhibit H, Tab 1, Schedule 1, Attachments 1 and 2**, 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 – 411.4 kcmil ACSR/TW conductor
2. Alternative 2 – 477.0 kcmil ACSR conductor

Analysis and Recommendations

All alternatives listed above address the supply load need of the Project and provide a reliable supply to customers in the area. The following screening analysis considers the impact of line losses. The screening analysis ("Screening Analysis") summarized in Table

1 below was conducted in accordance with Hydro One's Transmission Line Loss Guideline.[1]

Table 1 - Project Line Loss Screening Analysis

	Alt. #1 (411.4 kcmil ACSR/TW)	**Alt. #2** (477.0 kcmil ACSR)
Net Capital Cost [2] ($M)	26.32	26.44
Losses at Peak Flow [3] (MW)	0.066	0.057
Losses at System Peak (MW)	0.013	0.011
Annual Revenue Costs ($M)	1.99	2.00
Annual Cost of Capital to Cover Losses ($M)	0.0022	0.0019
Annual Cost of Energy Losses ($M)	0.031	0.026
Annual Cost of Losses [4] ($M)	0.033	0.028
Total Annual Cost [5] ($M)	**2.026**	2.031

The Screening Analysis, as shown in Table 1 above did not result in a change in the alternative ranking, to the proposed conductor in this Application. Despite conservatively considering the cost of line losses using peak flow and losses at system peak, the standard conductor alternative was found to present a lower Total Annual Cost for the ratepayer. The Screening Analysis conclusively demonstrates that Alternative #1's conductor is the most economically efficient alternative for the Project, and as such, consistent with the Hydro One Transmission Line Loss Guideline, no further analysis is required.

[1] As filed in proceeding EB-2023-0197, Exhibit I, Tab 2, Schedule 1, Attachment 1.
[2] Net Capital Cost is the total Project cost net of removals; and was based on a project definition equivalent to a Class 3 estimate based on the AACE estimate classification system for all alternatives.
[3] Losses based on anticipated future 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.

QUANTITATIVE AND QUALITATIVE BENEFITS OF THE PROJECT

Completion of the Project will enhance the long-term safety, reliability, and sustainability of the transmission facilities serving customers in the Kirkland Lake area by renewing obsolete and deteriorated infrastructure and mitigating identified asset risks.

More specifically the K1/K2 Refurbishment Project will deliver the following benefits:

- maintain reliable electrical service to customers in the Kirkland Lake area connected to the K2 circuit through the replacement and refurbishment of obsolete and deteriorated transmission infrastructure;
- enhance public and worker safety while improving transmission corridor reliability and maintainability by removing the remaining conductor and associated equipment of the idle K1 circuit;
- decrease the likelihood of unplanned outages and help ensure a reliable supply of electricity to customers in the Kirkland Lake area by proactively addressing asset needs; and
- ensures compliance with current engineering, safety, and operating standards.

The broader system benefits associated with the Project are identified in the applicable RIP provided in **Exhibit H, Tab 1, Schedule 1, Attachment 2.**

Hydro One also conducted an economic analysis to assess ratepayer impacts associated with transmission line losses for the conductor alternatives under consideration. The results of the economic analysis are further discussed in **Exhibit B, Tab 5, Schedule 1.**

Lastly, in accordance with the OEB CEO Policy regarding the IEP issued January 30, 2026[1], it is noted that though the Project is not explicitly identified in the IEP, the Project aligns with one of the core principles of the IEP, specifically reliability. Reliability is detailed in the IEP as building a system that works 24/7, in every season and every part of the

[1] OEB CEO Policy 2026-01

province. By proactively replacing poor condition obsolete conductor, the Project aligns with the reliability principles of the IEP and ensures that reliability in the Kirkland Lake area is maintained.

APPORTIONING PROJECT COSTS AND RISKS

The estimated total capital cost of the Project is $26.3M[1]. A breakdown of the capital cost estimate is shown below in Table 1 below.

Table 1 - Project Cost

	Estimated Cost ($000's)
Materials	1,767
Labour	4,912
Equipment Rental & Contractor Costs	13,246
Sundry	604
Contingencies	2,660
Overhead	2,003
Allowance for Funds Used During Construction [3]	803
Real Estate	325
Total Line Work[4]	26,320

The cost of the work provided above allows for the schedule of approval, design and construction activities to proceed as set out in the Project Schedule at **Exhibit B, Tab 11, Schedule 1**.

The cost estimates provided in Table 1 of this Schedule, and similarly the Project Schedule provided at **Exhibit B, Tab 11, Schedule 1,** are based on a project definition equivalent to a Class 3[5] under the AACE International (formerly the Association for the Advancement of Cost Engineering) estimate classification system[6].

[1] There will be approximately an additional $2.1M of OM&A removal costs associated with constructing this Project.
[3] AFUDC is calculated using the Board'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] Total Project capital cost includes nominal station-related costs related to protection setting changes of approximately $10k.
[5] An estimate range of -20%/+30%.

1.0 AVOIDED SUSTAINMENT WORK

No avoided sustainment work has been identified for this Project.

2.0 RISKS AND CONTINGENCIES

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

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

- **Temporary Generation Costs:** The refurbishment of Circuit K2 requires an extended outage of the transmission circuit during construction. A customer on the circuit does not have an alternate grid source of electrical supply and, as such, Hydro One will be required to provide temporary generation to maintain electrical service during the Project outage period. Project costs may increase due to factors such as higher-than-anticipated customer load requirements, fuel price volatility, changes to temporary generation requirements, customer facility connection requirements, or construction schedule delays that extend the duration of generator deployment.
- **Regulatory Approval:** The Project is dependent on obtaining OEB leave to construct in time to support the planned 2027 construction outage window. The outage window aligns with a customer's care-and-maintenance period, during which the customer's electrical demand is expected to be reduced by approximately 90% of its normal operations. This demand reduction makes temporary generation viable, practical and cost-effective for maintaining customer supply during Project execution. Delays in obtaining regulatory approvals could result in the loss of this low-load operating window and require Hydro One to re-evaluate alternative supply solutions, such as a temporary bypass or a greenfield construction option. These alternatives would require additional real estate rights,

more complex construction activities, multiple planned outages, and extended implementation schedules, resulting in increased Project cost, execution complexity, customer dissatisfaction, and impacts to the current Project Schedule.

To address the above-mentioned risks Hydro One has implemented the following measures:

1. Developed an execution strategy in collaboration with the customer to minimize the duration of the outage period and associated generation costs. In parallel, Hydro One continues to optimize construction sequencing and evaluate the use of natural gas generation as an alternative to diesel generation to reduce overall temporary power costs and exposure to fuel price volatility.
2. Advanced Project development, regulatory activities, real estate requirements, and supporting documentation in parallel to support timely submission and review of the Project's Leave to Construct application.

Due to the unlikelihood or uncertainty of occurrence, cost contingency has not been included for:

- Environmental or safety incidents
- Labor disputes
- Major fluctuations in material costs or availability that are outside Hydro One's control
- Any other unexpected events or situations that could significantly affect the Project

3.0 COSTS OF COMPARABLE PROJECTS - LINES

Chapter 4 of the OEB Filing Requirements for Electricity Transmission Applications requires an Applicant to provide the cost of comparable projects constructed by the Applicant. Table 2 below compares the K1/K2 Refurbishment Project with three recent 115 kV transmission line refurbishment projects: the K4 Line Refurbishment Project, the D6 Line Refurbishment Project, and the X2Y Line Refurbishment Project.

The K4 Line Refurbishment Project: Refurbishment of approximately 10 km of a 115 kV single-circuit transmission line (Circuit nomenclature 'K4') utilizing wood pole structures in the Kirkland Lake area of Northern Ontario that connects Kirkland Lake TS and Young–Davidson CTS. The project consisted of two sections: the first section included the replacement of conductors, all supporting wood pole H-frame structures, and associated hardware along the existing circuit ROW; and the second section involved construction of a single-circuit transmission line on H-frame wood pole structures along a new ROW east of the existing line. Leave to construct approval for this project was granted under OEB docket EB-2023-0197. The project was placed in service in October 2024.

D6 Transmission Line Refurbishment Project ("D6 Line Refurbishment Project") between Des Joachims TS X Chalk River JCT and Petawawa JCT X Craig JCT/Petawawa DS: In-situ sustainment of 48 km of existing 115 kV single-circuit wood pole transmission line (Circuit nomenclature 'D6') between Des Joachims TS X Chalk River JCT and Petawawa JCT X Craig JCT/Petawawa DS. This project included replacement of conductors, all supporting structures (using a combination of composite and wood due to pole damage risk from woodpecker bird species), and associated hardware. The project utilized 411.4 kcmil conductor. The project is in Northern Ontario and was placed in service in October 2022. The project was not subject to leave to construct approval by the OEB.

X2Y Transmission Line Refurbishment Project ("X2Y Refurbishment Project") between Magellan Aerospace CTS and IPB Bryson JCT: Refurbishment of a 7.6 km line section of an existing 115 kV single-circuit wood pole transmission line (Circuit nomenclature 'X2Y') between Magellan Aerospace CTS and IPB Bryson JCT. The project included the replacement of conductors, all supporting structures, and associated hardware. The project utilized 411.4 kcmil conductor. The project is located in Eastern Ontario in a rural setting and was completed in June 2020. The project was not subject to leave to construct approval by the OEB.

The above three projects were selected as reasonable comparators as they share key characteristics with the Project. Specifically, all involve 115 kV single-circuit transmission lines located in predominantly rural environments and include significant conductor and structure replacement activities. While these projects provide a reasonable basis for comparison, there are notable differences in facility configuration, scope, execution requirements, customer impacts, site conditions, and timing that must be considered when evaluating relative project costs.

The Project involves the refurbishment of approximately 13.7 km of transmission facilities consisting of wood pole structures and lattice towers. In addition to transmission line refurbishment activities, the Project includes the removal of the remaining conductor and shieldwire associated with the idle K1 circuit.

The Project includes temporary generation and associated connection facilities required to maintain electrical service to Agnico Eagle during the planned outage of Circuit K2. This requirement represents the most significant difference between the Project and the comparator projects. The costs associated with temporary generation are influenced by several factors, including fuel price volatility, tariffs, and broader market conditions affecting equipment availability and pricing. These costs are not incurred to deliver the comparator projects and represent a significant project-specific requirement.

In addition to temporary generation costs, the K1/K2 Refurbishment Project includes several scope elements that are either unique to the Project or materially different from those included in the comparator projects. These include rock drilling and foundation remediation activities, lattice tower reinforcement work, rider pole and bypass installations, real estate activities, and project-specific access requirements to support construction work. While some comparator projects included similar activities, most notably the K4 Refurbishment Project, the associated costs and execution requirements varied significantly between projects. Accordingly, adjustments have been made in Table 2 to account for these material scope differences, where necessary, to facilitate a more meaningful comparison of the underlying transmission line refurbishment costs.

An adjustment was also made to the Project to account for incremental costs associated with new tariffs effective December 26, 2025, whereby the Government of Canada imposed a 25% tariff on imported steel derivative products, including tower steel structures, conductors and tower foundation steel materials.[7]

Table 2, below, has also been adjusted to show comparable projects in 2028 dollars utilizing inflation values for future years consistent with the inflation parameters provided by the OEB[8].

The comparator projects were also completed prior to the significant inflationary pressures experienced across the utility and construction sectors in recent years. The current market environment continues to impact project costs through higher labour rates, increased material and equipment costs, ongoing supply chain constraints, commodity price volatility, tariffs, and geopolitical uncertainty affecting the cost and availability of materials and equipment. While escalation adjustments have been applied to the comparator projects utilizing a conservative escalation of the OEB inflation factor, these adjustments may not fully capture project-specific cost drivers associated with the procurement of transmission line materials, temporary generation services, and customer continuity-of-service requirements unique to the Project. As a result, differences in adjusted unit costs between the comparator projects and the Project should be considered in the context of both current market conditions and the Project's unique execution requirements.

When this context is coupled with the adjusted comparable cost per km ratio for all other transmission line costs in Table 2, the comparable projects demonstrate that the cost estimate for the K1/K2 Project is consistent with costs to complete comparable transmission line works and is reasonable.

[7] https://www.canada.ca/en/department-finance/news/2025/12/list-of-steel-derivative-products-subject-to-25-per-cent-tariffs-effective-december-26-2025.html
[8] As most recently updated by the OEB on June 11, 2026.

Table 2 - Costs of Comparable Line Projects

Project	Circuit K4 Refurbishment Project (Line Cost)	Circuit D6 Refurbishment - 48 km Completed (Line Cost)	Circuit X2Y Refurbishment Project (Line Cost)	Circuit K1/K2 Refurbishment Project (Line Cost)
Circuit Operating Designation(s)	K4	D6	X2Y	K2
Voltage	115 kV	115 KV	115 KV	115 kV
Structure Type	Wood pole (H-Frame / Single-Pole)	Wood Pole/Composite (208 Str- primarily H-Frames)	Wood Pole (66 Str- primarily single poles)	Wood Poles & Lattice Towers
Single or Double Circuit	Single	Single	Single	Single
Conductor	997.0 kcmil	411.4 kcmil	411.4 kcmil	411.4 kcmil
Location	Northern Ontario	Northern Ontario	Eastern Ontario	Northern Ontario
Project Surroundings	Rural	Rural	Rural	Rural
In-Service Year	2024	2022	2020	2027
Estimate or Actual	Actual	Actual	Actual	Estimate
OEB-Approved Cost Estimate	$13.9M[9]	N/A[10]	N/A[11]	–
Total Cost	$12,403K	$34,700K	$5,100K	$26,320K
Less Adjustments:				
Less: Foundations (Rock Drilling)	*$630K*	*N/A*	*N/A*	*$370K*
Less: Real Estate	*$1,464K*	*N/A*	*N/A*	*$650K*
Less: Steel and BPE X-M Towers	*$120K*	*N/A*	*N/A*	*$890K*
Less: Install and Removal of Rider Poles / Bypass	*$156K*	*N/A*	*N/A*	*$370K*
Less: Forestry	*$292K*	*N/A*	*N/A*	*$41K*
Less: Larger Conductor	$64K	*N/A*	*N/A*	*N/A*
Less: Switches	*N/A*	*N/A*	*N/A*	*$130K*
Less: Temporary Generation Supply	*N/A*	*N/A*	*N/A*	*$9,620K*
Less: Newly Enacted Tariff	*N/A*	*N/A*	*N/A*	*$246K*
Comparable Costs, before Escalation	$9,677K	$34,700K	$5,100K	$14,003K
Escalation Adjustment[13]	$1,157K	$7,322K	$1,400K	N/A
Total Adjusted Comparable Cost	$10,834K	$42,020K	$6,500K	$14,003
Approximate Length	10 km	48 km	7.6 km	13.7 km
Unit Cost	**$1,083 K/km**	**$880 K/km**	**$860 K/km**	**$1,024 K/km**

[9] As per the Section 92 leave to construct proceeding evidence in EB-2023-0197.
[10] The project was not subject to leave to construct approval by the OEB. Therefore, the specific investment does not have a discrete OEB approval to appropriately reference for the purposes of this comparison.
[11] ibid
[13] Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.

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CONNECTION PROJECTS REQUIRING NETWORK REINFORCEMENT

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

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TRANSMISSION RATE IMPACT ASSESSMENT

1.0 ECONOMIC FEASIBILITY

The Project costs will be included in the line connection 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 line connection pool work demonstrates that based on the estimated initial cost of $28.4 million[2], plus the assumed impact on the future capital cost allowance, Hydro One's corporate income tax and no annual incremental line connection revenue utilizing the 2026 UTR over a 25-year evaluation period, this Project will have a negative net present value of $24.7 million as seen in Tables 2 and 3.

2.0 COST RESPONSIBILITY

Line Connection Pool

The K2 circuit is a radial line that connects customers through Kirkland Lake TS. Based on the cost allocation methodology approved by the OEB[5] in Hydro One's most recent transmission rate filing, the line assets are allocated 100% to the Line Connection Pool.

3.0 RATE IMPACT ASSESSMENT

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

[2] Initial line connection costs of $28.4 million include $26.3 million of up-front capital costs plus $2.1 million cost of removals.
[5] EB-2021-0110, Exhibit H, Tab 1, Schedule 2

Line Connection Pool

Based on the estimated initial cost of $28.4 million and the associated line pool incremental cash flows, there will be a change in the line pool revenue requirement once the Project's impacts are reflected in the transmission rate base at the projected in-service date of October 31, 2027. The 2026 OEB approved rate of $1.03 per kW/month increases to $1.04 per kW/month in the second year, then decreases back to 1.03 per kW/month in the 21st year over a 25-year time horizon. The detailed analysis illustrating the calculation of the incremental line revenue and rate impact is provided in Tables 4 and 5 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 line connection pool will result in a $0.02 per month increase in a typical residential customer's bills under the RPP. The table below shows this result for a typical residential customer who is under the RPP, utilizing the maximum impact by rate pool, regardless of year.

Table 1 - Rate Impact on Typical Residential Customer Bill

A. Typical monthly bill	$168.81 per month
B. Transmission component of monthly bill	$18.08 per month
C. Line Connection Pool share of Transmission component	$1.74 per month
D. Transformation Connection Pool share of Transmission component	$5.85 per month
E. Network Connection Pool share of Transmission component	$10.49 per month
F. Impact on Line Connection Pool Provincial Uniform Rates	0.97%
G. Impact on Transformation Connection Pool Provincial Uniform Rates	0.00%
H. Impact on Network Connection Pool Provincial Uniform Rates	0.00%
I. % Impact of Network, Line & Transformation Connection Pool UTR	0.1%
J. Increase in Transmission costs for typical monthly bill (B x I)	$0.02 per month or $0.24 per year
K. Net increase on typical residential customer bill (J / A)	0.01%

Table 2 - Net Present Value, Line Connection Pool, Page 1

Date:	8-Jul-26
Project #	24270

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Hydro One Transmission Circuit K2
Description:	Refurbishment of Tx circuit K2 between Kirkland Lake TS X American Barrick JCT (Str. 92)
Customer:	Rate base work - no customer contribution

			In-Service Date	<------- Project year ended - annualized from In-Service Date ------->											
		Month / Year	Oct-31 2027	Oct-31 2028	Oct-31 2029	Oct-31 2030	Oct-31 2031	Oct-31 2032	Oct-31 2033	Oct-31 2034	Oct-31 2035	Oct-31 2036	Oct-31 2037	Oct-31 2038	Oct-31 2039
			0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast															
Load Forecast (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
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tariff Applied ($/kW/Month)				1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03
Incremental Revenue - $M				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Removal Costs - $M			(2.1)												
On-going OM&A Costs - $M			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M				(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M			(2.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Income Taxes			0.5	0.3	0.6	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3
Operating Cash Flow (after taxes) - $M			(1.5)	0.2	0.5	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2
		Cumulative PV @ 5.65%													
PV Operating Cash Flow (after taxes) - $M	**(A)**	**1.5**	**(1.5)**	**0.2**	**0.4**	**0.4**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(23.5)												
- Overheads			(2.0)												
- AFUDC			(0.8)												
Total upfront capital expenditures			**(26.3)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(26.3)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**0.1**												
PV Working Capital - $M			**0.0**												
PV Capital (after taxes) - $M	**(B)**	**(26.2)**	**(26.2)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(24.7)**	**(27.7)**	**(27.5)**	**(27.1)**	**(26.7)**	**(26.4)**	**(26.1)**	**(25.9)**	**(25.7)**	**(25.5)**	**(25.4)**	**(25.2)**	**(25.1)**	**(25.0)**

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**
Discount Rate - %		**5.65%**
		$M
PV Incremental Revenue		0.0
PV OM&A Costs		(2.1)
PV Municipal Tax		(1.2)
PV Income Taxes		0.9
PV CCA Tax Shield		4.0
PV Capital - Upfront	(26.3)	
Add: PV **Capital Contribution**	**0.0**	(26.3)
PV Capital - On-going		0.0
PV Working Capital		0.0
PV Surplus / (Shortfall)		**(24.7)**
Profitability Index*		**0.1**

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

Other Assumptions

In-Service Date:	31-Oct-27
Payback Year:	2052
No. of years required for payback:	25

Table 3 - Net Present Value, Line Connection Pool, Page 2

Date:	8-Jul-26
Project #	24270

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Hydro One Transmission Circuit K2
Description:	Refurbishment of Tx circuit K2 between Kirkland Lake TS X American Barrick JCT (Str. 92)
Customer:	Rate base work - no customer contribution

		<------- Project year ended - annualized from In-Service Date -------->												
Month		Oct-31	Oct-31	Oct-31	Oct-31	Oct-31	Oct-31	Oct-31	Oct-31	Oct-31	Oct-31	Oct-31	Oct-31	Oct-31
Year		**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**
		13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast														
Load Forecast (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
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	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)		1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03
Incremental Revenue - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Removal Costs - $M														
On-going OM&A Costs - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M		(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M		(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Income Taxes		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Operating Cash Flow (after taxes) - $M		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
PV Operating Cash Flow (after taxes) - $M	**(A)**	**0.1**	**0.1**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	**(B)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(25.0)**	**(24.9)**	**(24.9)**	**(24.8)**	**(24.8)**	**(24.7)**	**(24.7)**	**(24.7)**	**(24.7)**	**(24.7)**	**(24.7)**	**(24.7)**	**(24.7)**

Table 4 - Revenue Requirement and Line Connection Pool Rate Impact, Page 1

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

Hydro One Transmission Circuit K2		Project YE 31-Oct 2028	31-Oct 2029	31-Oct 2030	31-Oct 2031	31-Oct 2032	31-Oct 2033	31-Oct 2034	31-Oct 2035	31-Oct 2036	31-Oct 2037	31-Oct 2038	31-Oct 2039
Calculation of Incremental Revenue Requirement ($ millions)		1	2	3	4	5	6	7	8	9	10	11	12
In-service date	31-Oct-27												
Capital Cost	26.3												
Less: Capital Contribution Required	-												
Net Project Capital Cost	26.3												
Average Rate Base		12.9	25.5	25.0	24.5	24.0	23.5	22.9	22.4	21.9	21.4	20.8	20.3
Incremental OM&A Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grants in Lieu of Municipal tax		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Depreciation		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Interest and Return on Rate Base		0.8	1.6	1.6	1.6	1.5	1.5	1.5	1.4	1.4	1.4	1.3	1.3
Income Tax Provision		(0.0)	(0.2)	(0.1)	(0.1)	(0.0)	(0.0)	0.0	0.1	0.1	0.1	0.1	0.1
REVENUE REQUIREMENT PRE-TAX		**1.4**	**2.0**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.0**
Incremental Revenue		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SUFFICIENCY/(DEFICIENCY)		**(1.4)**	**(2.0)**	**(2.1)**	**(2.1)**	**(2.1)**	**(2.1)**	**(2.1)**	**(2.1)**	**(2.1)**	**(2.1)**	**(2.1)**	**(2.0)**
	Base Year												
Line Pool Revenue Requirement including sufficiency/(deficiency)	232	234	234	234	234	234	234	234	234	234	234	234	234
Line MW	226	226	226	226	226	226	226	226	226	226	226	226	226
Line Pool Rate ($/kw/month)	1.03	1.03	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
Increase/(Decrease) in Line Pool Rate ($/kw/month), relative to base year		0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
RATE IMPACT relative to base year		**0.00%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**

Assumptions

Incremental OM&A		$3.68037852575368 k per new km of line each year.
Grants in Lieu of Municipal tax	0.33%	Transmission system average
Depreciation	2.00%	Reflects 50 year average service life for towers, conductors and station equipment, excluding land
Interest and Return on Rate Base	6.34%	Includes OEB-approved ROE of 9.36%, 4.79% on ST debt, and 4.3% on LT debt. 40/4/56 equity/ST debt/ LT debt split
Income Tax Provision	26.50%	2026 federal and provincial corporate income tax rate
Capital Cost Allowance	8.00%	99.5% Class 47 assets except for Land

Table 5 - Revenue Requirement and Line Connection Pool Rate Impact, Page 2

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

Hydro One Transmission Circuit K2		31-Oct 2040	31-Oct 2041	31-Oct 2042	31-Oct 2043	31-Oct 2044	31-Oct 2045	31-Oct 2046	31-Oct 2047	31-Oct 2048	31-Oct 2049	31-Oct 2050	31-Oct 2051	31-Oct 2052
Calculation of Incremental Revenue Requirement ($ millions)		13	14	15	16	17	18	19	20	21	22	23	24	25
In-service date	31-Oct-27													
Capital Cost	26.3													
Less: Capital Contribution Required	-													
Net Project Capital Cost	26.3													
Average Rate Base		19.8	19.3	18.8	18.2	17.7	17.2	16.7	16.2	15.6	15.1	14.6	14.1	13.5
Incremental OM&A Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grants in Lieu of Municipal tax		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Depreciation		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Interest and Return on Rate Base		1.3	1.2	1.2	1.2	1.1	1.1	1.1	1.0	1.0	1.0	0.9	0.9	0.9
Income Tax Provision		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
REVENUE REQUIREMENT PRE-TAX		**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**1.9**	**1.9**	**1.9**	**1.9**	**1.8**	**1.8**	**1.8**	**1.7**
Incremental Revenue		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SUFFICIENCY/(DEFICIENCY)		**(2.0)**	**(2.0)**	**(2.0)**	**(2.0)**	**(2.0)**	**(1.9)**	**(1.9)**	**(1.9)**	**(1.9)**	**(1.8)**	**(1.8)**	**(1.8)**	**(1.7)**
	Base Year													
Line Pool Revenue Requirement including sufficiency/(deficiency)	232	234	234	234	234	234	234	234	234	234	234	234	234	234
Line MW	226	226	226	226	226	226	226	226	226	226	226	226	226	226
Line Pool Rate ($/kw/month)	1.03	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.03	1.03	1.03	1.03	1.03
Increase/(Decrease) in Line Pool Rate ($/kw/month), relative to base year		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00
RATE IMPACT relative to base year		**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**

Table 6 - 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%**

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REVENUE REQUIREMENT INFORMATION AND DEFERRAL ACCOUNT REQUESTS

1.0 REVENUE REQUIREMENT AND TRANSMISSION SYSTEM PLAN INFORMATION

The Project was not individually identified in an Investment Summary Document within Hydro One's Transmission System Plan that supported its most recent 2023-2027 transmission rate application (EB-2021-0110).

2.0 DEFERRAL ACCOUNT REQUEST INFORMATION

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

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PROJECT SCHEDULE

TASK	START	FINISH
Section 92 Approval	Sept 2026	Feb 2027
LINES		
Receipt of Other Key Permits and Approvals	June 2026	Dec 2026
Voluntary Property Rights Acquisition[1]	Feb 2026	Sept 2026
Detailed Engineering	Jun 2026	Aug 2026
Procurement	August 2026	Feb 2027
Construction	Mar 2027	Oct 2027
Commissioning	Oct 2027	Oct 2027
In Service	N/A	Oct 2027
Site Remediation Completion	Oct 2027	Apr 2028

The Project Schedule above outlines the forecast schedule for the Project and has been predicated on Hydro One successfully securing leave to construct approval by February 2027. Construction is set to commence in March 2027 and the cost evidence provided in **Exhibit B, Tab 7, Schedule 1** is underpinned by this schedule**.** As identified in **Exhibit B, Tab 7, Schedule 1,** delays in regulatory approvals beyond those contemplated in the Project Schedule documented above could impact the cost of the Project. Contingency has been included in the Project cost to account for minor deviations to this schedule, however, material delays in securing approvals could have significant impacts that have not been included in the contingency cost forecast. Project timelines have been based on recent OEB processing timelines and take into consideration the OEB's Performance Standards for Processing Leave to Construct Applications.

[1] Completion timing is dependent upon property owner-specific negotiations. The above schedule does not include the timeframe for Section 99 if required.

As discussed in **Exhibit B, Tab 2, Schedule 1**, the proposed Project Schedule has been informed by a connected customer's low demand period window, thereby reducing the impact to the customer and reducing the overall total project costs that will be ultimately borne by transmission rate payers. Consequently, in aid of the Project Schedule, Agnico Eagle (the connected customer) has provided Hydro One with a letter of support for the Project. It can be found at **Attachment 1** to this Schedule.

Shevaughne Wynter

Transmission Account Executive

Hydro One Networks Inc.

6975 Kenderry Gate

Mississauga, Ontario L5T 2Y1

29th July 2026

Dear Mr. Wynter,

Re: Hydro One Networks Inc. – K1/K2 Transmission Line Refurbishment Project

Agnico Eagle Mines Limited ("Agnico Eagle") is supportive of Hydro One's proposed K1/K2 Transmission Line Refurbishment Project (the "Project"). Agnico Eagle understands that, with the Project, Hydro One will be able to deliver power to Agnico Eagle's Upper Beaver project. Agnico Eagle is also aware of the regulatory requirements with respect to the Ontario Energy Board ("OEB")'s S.92 leave to construct approval and are supportive of the OEB providing s.92 Approval to Hydro One to allow the Project construction to commence as planned.

Please also note that Agnico Eagle's Holloway Holt Mine facilities, as served by the K2 transmission circuit, are currently operating in a care and maintenance state while Agnico Eagle undertakes a review of the facilities. Therefore, the power consumption at Holloway Holt Mine is substantially lower than when the site is in active production. Agnico Eagle understands that Hydro One's tentatively proposed construction schedule, from March to October 2027, is primarily driven by these current minimal power supply requirements. Accordingly, Agnico Eagle has received a request from Hydro One for provision of temporary off-grid generation to sustain the power requirements of Holloway Holt Mine during the construction period.

Agnico Eagle understands the importance of the Project for its Upper Beaver project and is committed to working with Hydro One to complete the necessary off-grid generation at the Holloway Holt Mine in a timely manner.

If you have any questions, please do not hesitate to contact the undersigned.

Sincerely,

Andre Leite (Jul 30, 2026 07:21:35 EDT)

Andre Leite

Vice President Ontario

Agnico Eagle Mines Limited

DESCRIPTIONS OF THE PHYSICAL DESIGN

1. ROUTE DESCRIPTION

The proposed K1/K2 Refurbishment Project is in the Kirkland Lake region. The circuit spans between Kirkland Lake TS and American Barrick JCT. The total length of the Project is approximately 13.7 km and will utilize the existing transmission ROW.

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

1.1 ROUTE DETAILS

i. The K2 transmission route spans approximately 13.7 km between the termination Structure #92 of circuit K2 within Kirkland Lake TS and American Barrick JCT.
ii. Additionally, the first three structures (Structures: 9A, #A, and #B) of Gull Lake North JCT to Gull Lake South JCT are in poor condition and will be replaced.

2. LINE DESCRIPTION

The refurbished K2 single circuit 115 kV transmission line will be comprised of 411.4 kcmil ACSR/TW “Simcoe” conductor and a single 7#8 Alumoweld overhead shieldwire, primarily supported on pole-type transmission structures. The new poles installed will be wood, whereas the existing lattice structures and composite poles will be refurbished. Further, this 115kV transmission line will have the following attributes:

i. a continuous ampacity of 405A (75°C, at summer ambient 35°C);
ii. glass type insulators;
iii. Stockbridge dampers;
iv. six wood three-pole type dead-end structure replacements;
v. 20 H-Frame wood pole type suspension structures replacements;
vi. six lattice structure refurbishments including foundation restorations as required;
vii. 17 composite structure refurbishments;
viii. all pole type structures will be directly embedded; and
ix. replacement of all line hardware, bonding, and grounding connections.

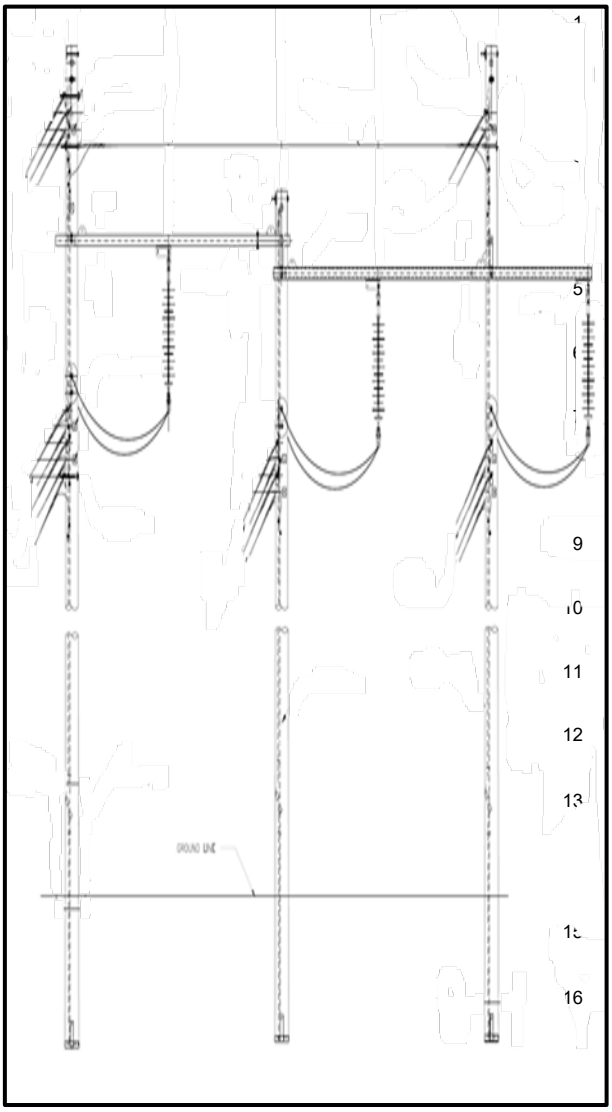


Figure 1: Three Pole Dead-End Structure

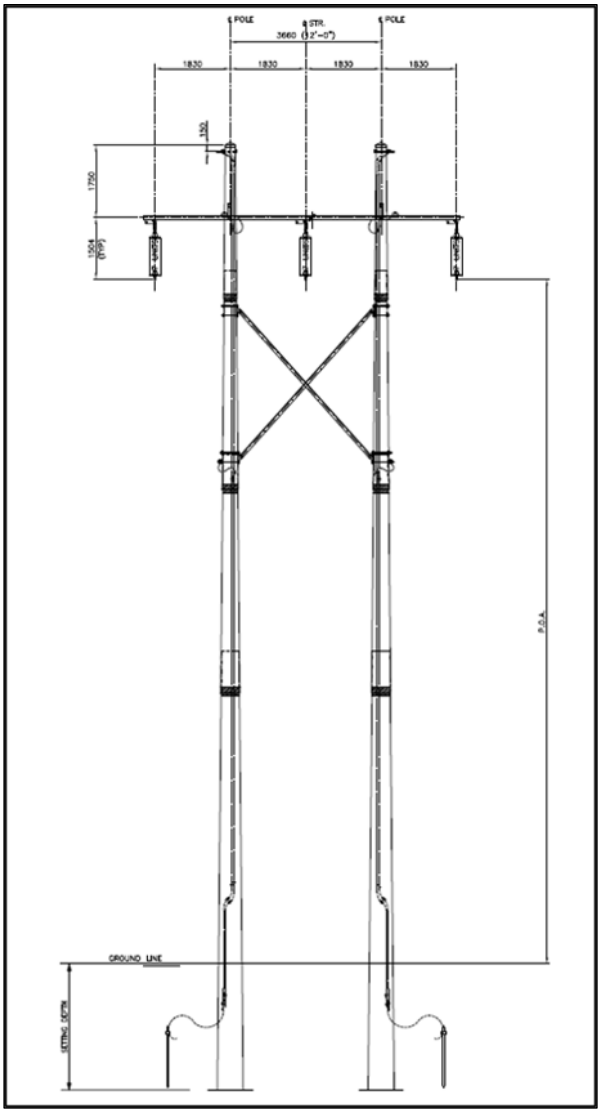


Figure 2: H-frame Type Suspension

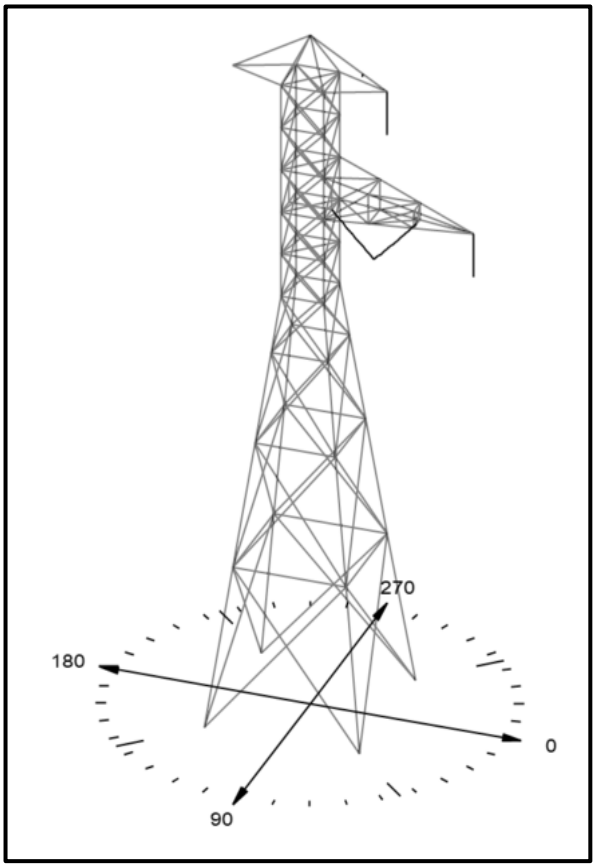


Figure 3: Typical Lattice Suspension Tower modification

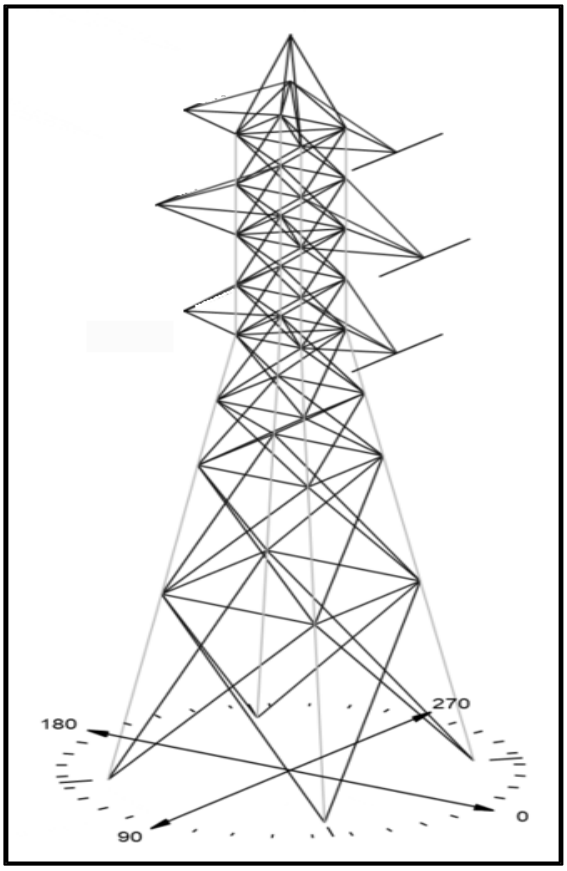


Figure 4: Typical Lattice Dead-end Tower modification

3. LINE REMOVAL

Existing conductor and shieldwire of circuit K2 between Kirkland Lake TS and American Barrick JCT will be removed and the remaining segments of the conductor on the idle K1 circuit will also be removed.

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OPERATIONAL DETAILS

The Project involves the refurbishment of an existing transmission line facility (circuit K2) located in the Kirkland Lake area. The Project will remain part of the 115 kV transmission system and is required to continue to provide reliable supply for the North/East of Sudbury region. The Project circuit's route is situated between the terminal facilities of the Kirkland Lake TS and American Barrick JCT, as described in the Application. Minor settings modifications made to Hydro One's protection, control and telecom facilities as part of the Project will protect the proposed transmission line by detecting faults and isolating faulted elements. The proposed facility will be operated by Hydro One's ISOC as directed by the IESO.

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LAND MATTERS

1.0 THE ROUTE

The K1/K2 Refurbishment Project's single circuit 115 kV transmission line will be located within an existing transmission corridor ranging from 30-46m in width in the Kirkland Lake area. The Project route traverses both private and municipal owned lands.

2.0 DESCRIPTION OF LAND RIGHTS

The Project corridor crosses 38 properties. The rights across the corridor were reserved through Crown patents issued at the time of original land disposition. Hydro One is obtaining registered easements over the affected properties where such Crown reservations exist. Hydro One's ROW for the circuits were acquired in the late 1920s and early 1930s around the time when many of the lands were being patented. Of the 38 properties, 32 have clearly defined rights via registered easement or reservations of the crown patent. The remaining six properties were patented contemporaneously with the construction and acquisition of the transmission corridor. On these six properties, Hydro One is seeking to obtain registered land rights from the current property owners through voluntary settlement. The six impacted properties are owned by four separate landowners. Hydro One has, and continues to, work with those directly impacted property owners to finalize any necessary voluntary land right agreements.

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

Table 1 - Summary of Property Types and Sized Required

Land Ownership Type	Area (Hectares)	Proportion of Route (%)
Private Lands	7.92	100

3.0 MAPS OF THE PROJECT AREA

At **Exhibit B, Tab 2, Schedule 1, Attachment 1**, Hydro One has provided a copy of a map with the intention it be used as the Application's *Notice Map* should the OEB determine that a hearing is required. **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:

- Easement rights on properties where the acquisition of new permanent lands rights are required;
- Temporary access and/or construction rights on municipally owned and private properties for access roads, temporary work headquarters, laydown areas, and material storage facilities.

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

- Grant of Easement;
- Off Corridor Access; and
- Damage Claim Agreement/Waiver.

Where crossings of public roads and highways are contemplated and indicated in **Attachment 2** of this Schedule, Hydro One will rely on the land rights afforded by section 41 of the *Electricity Act , 1998, S. O. 1998, c. 15, Sched. A* (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, 1998*. All road crossings will be designed to meet or exceed CSA vertical clearance standards. Structures shall be located so that tower legs and guy wire anchor locations (above ground) are at least 15 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 private lands to facilitate construction of the Project. These rights will be negotiated and acquired as and when needed.

5.0 LAND ACQUISITION PROCESS

Hydro One is seeking approval of the voluntary property rights agreements that are intended to be used with affected property owners. Hydro One's valuation approach for the six privately held properties that Hydro One requires for this Project is based on similarly-situated northern property values. Hydro One prepared voluntary property settlement offers for those six properties based on those aforementioned values. Hydro One began providing offers to affected property owners in August 2025. As of September 2026, six voluntary property settlement offers have been made, and four offers have been accepted. One landowner has yet to accept the offer; this owner owns two of the six total impacted properties. Discussions with that landowner are ongoing and the agreements are being reviewed by the property owner and their legal counsel for the two unique properties outstanding. Hydro One remains confident that those agreements can be acquired in a timely manner and on a voluntary basis. To that end, it should be noted that during property acquisition discussions, affected property owners are advised that they have the option to receive independent legal advice and that Hydro One is committed to reimbursing affected property owners for reasonably incurred legal fees associated with the review and execution of the necessary land rights agreements. Hydro One will continue working with each property owner with the objective of reaching voluntary property rights settlements.

All voluntary property rights agreements will be in the form of an easement agreement. Hydro One will register these agreements and conclude the land rights agreement transfer process once it has received the OEB's s.92 Leave to Construct approval of the Project. For the easements that are signed, once Hydro One has been granted S.92 approval, Hydro One will register those easements on title for the outstanding properties 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 September 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	6	0%	0%	6	4	Permanent Land requirement width	Continue to Negotiate

6.0 LAND-RELATED FORMS

Attachments 3 through 5 of this Schedule contain copies of the land rights agreements that Hydro One has, and intends to, utilize to obtain the required new land rights for the Project and for related Project activities. Table 3 below sets out the proceeding in which the form of these agreements were previously approved. No substantive changes have been made to the forms of these agreements.

Table 3 - Forms of Agreement Remaining Unchanged

Form of Agreement	Attachment in this Schedule	Previous OEB Docket
Off Corridor Access	4	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 10
Damage Claim Agreement/Waiver	5	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 12

Table 4, below, indicates the prior s.92 leave to construct proceeding where the form of these agreements are materially unchanged to those previously approved, with the exception of the following change: the Grant of Easement document utilized for the easements pertaining to this Project includes identical terms and conditions as the easements registered via an Option Agreement that was used in the prior EB-2024-0155, except it was a greenfield corridor Project. For this Project, the transmission line corridor

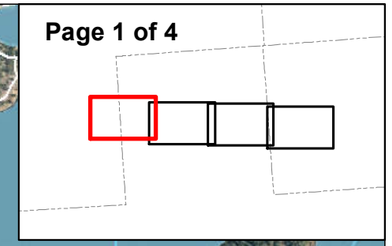
is already established because an existing transmission line was constructed within it. Accordingly, this is a brownfield project.

Table 4 - Forms of Agreement Remaining Materially Unchanged

Form of Agreement	Attachment to this Schedule	Previous OEB Docket
Grant of Easement	3	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 4

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DETAILED ROUTING MAPS



HYDRO RD
SIMMS RD
BRANT ST
WILSON AVE
HEATH ST
DAY AVE
GREEN AVE
BROWN AVE
WISHMAN ST
FOSS RD
K4
GRIERSON RD
FEDERAL ST
A9K
A8K STR 803 JCT
Kirkland Lake
ALGONQUIN AVE
MACPHERSON AVE
ATKINS AVE
BURNSIDE CRT
HILLCREST DR
WEEDSMUIR RD
HARDING AVE
KIRKLAND LAKE TS
A8K
NIPISSING LANE
STATION RD N
BURNSIDE DR
TOBURN RD
GOVERNMENT RD E
HOSPITAL GREEN RD
HIGHWAY 66
DISTRICT OF TIMISKAMING
Gull Lake
Timiskaming, Unorganized, West Part
LEBEL
GOODFISH RD
TOWN OF KIRKLAND LAKE
DUNCAN AVE N
TECK
STATION RD
TOWER ST
YOUNG AVE
1 ST
2 ST E
3 ST
4 ST
5 ST
ALLEN AVE
KIRKLAND ST E
WATER ST
MARKET ST
KIRKLAND ST
KIRKPATRICK ST
2 ST W
GOVERNMENT RD W
HUDSON BAY AVE
MCCAMUS AVE
CHURCHILL DR
CALBECK AVE
Murdock Creek
FURLONG ST
CARTER AVE
SPRUCE ST
BALSAM AVE
PREMIER AVE E
RAND AVE
POLLOCK ST
GULL LAKE NORTH JCT
GULL LAKE SOUTH JCT
K2 STR 1 JCT
K2
D3K
HARVEY KIRKLAND RD
(612281354)
(612281341)
(612280997)
(614080860)
(614080100)
(614080160)
(614080562)
(614080892)
(614080530)
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(614080647)
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(612270399)
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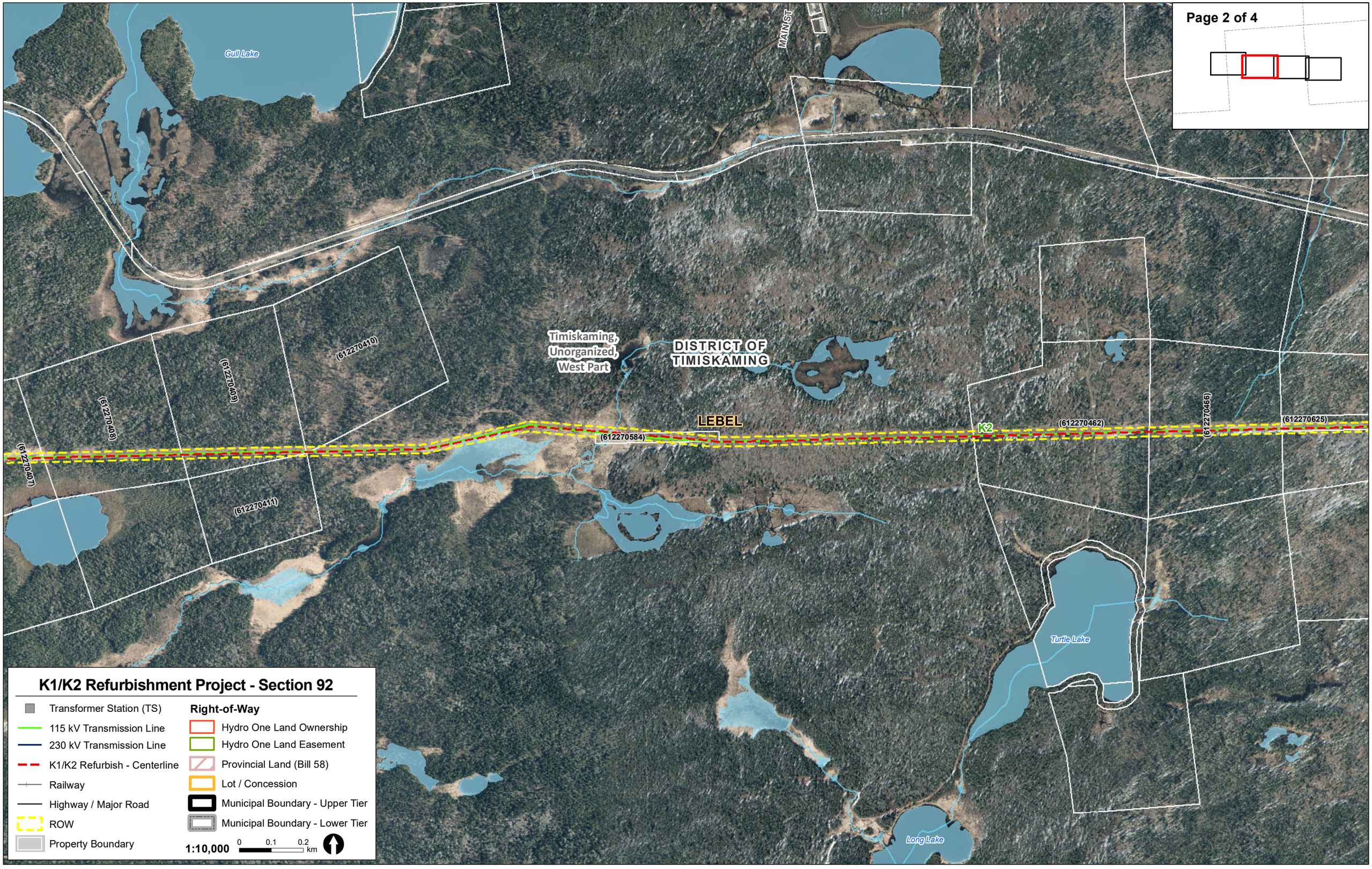
K1/K2 Refurbishment Project - Section 92

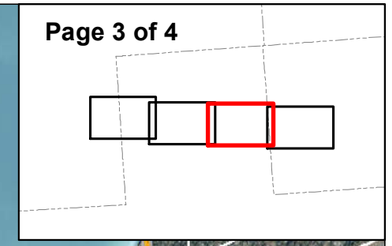
- Transformer Station (TS)
- 115 kV Transmission Line
- 230 kV Transmission Line
- K1/K2 Refurbish - Centerline
- Railway
- Highway / Major Road
- ROW
- Property Boundary

Right-of-Way

- Hydro One Land Ownership
- Hydro One Land Easement
- Provincial Land (Bill 58)
- Lot / Concession
- Municipal Boundary - Upper Tier
- Municipal Boundary - Lower Tier

1:10,000 0 0.1 0.2 km


Page 2 of 4
Gull Lake
MAIN ST
Timiskaming, Unorganized, West Part
DISTRICT OF TIMISKAMING
LEBEL
(612270584)
K2
(612270462)
(612270625)
(612270466)
(612270410)
(612270409)
(612270408)
(612270407)
(612270411)
Turtle Lake
Long Lake
K1/K2 Refurbishment Project - Section 92
Transformer Station (TS)
115 kV Transmission Line
230 kV Transmission Line
K1/K2 Refurbish - Centerline
Railway
Highway / Major Road
ROW
Property Boundary
Right-of-Way
Hydro One Land Ownership
Hydro One Land Easement
Provincial Land (Bill 58)
Lot / Concession
Municipal Boundary - Upper Tier
Municipal Boundary - Lower Tier
1:10,000
0 0.1 0.2 km



Crystal Lake

(612260005)

(612270680)

HIGHWAY 66

GAUTHIER

TOWNSHIP OF GAUTHIER

(612270466)

(612270625)

(612270471)

(612270478)

(612270487)

K2

(612270487)

LEBEL

(612270656)

(612270574)

(612270595)

(612260168)

DISTRICT OF TIMISKAMING

Timiskaming, Unorganized, West Part

(612270692)

Jordan Lake

Wilson Lake

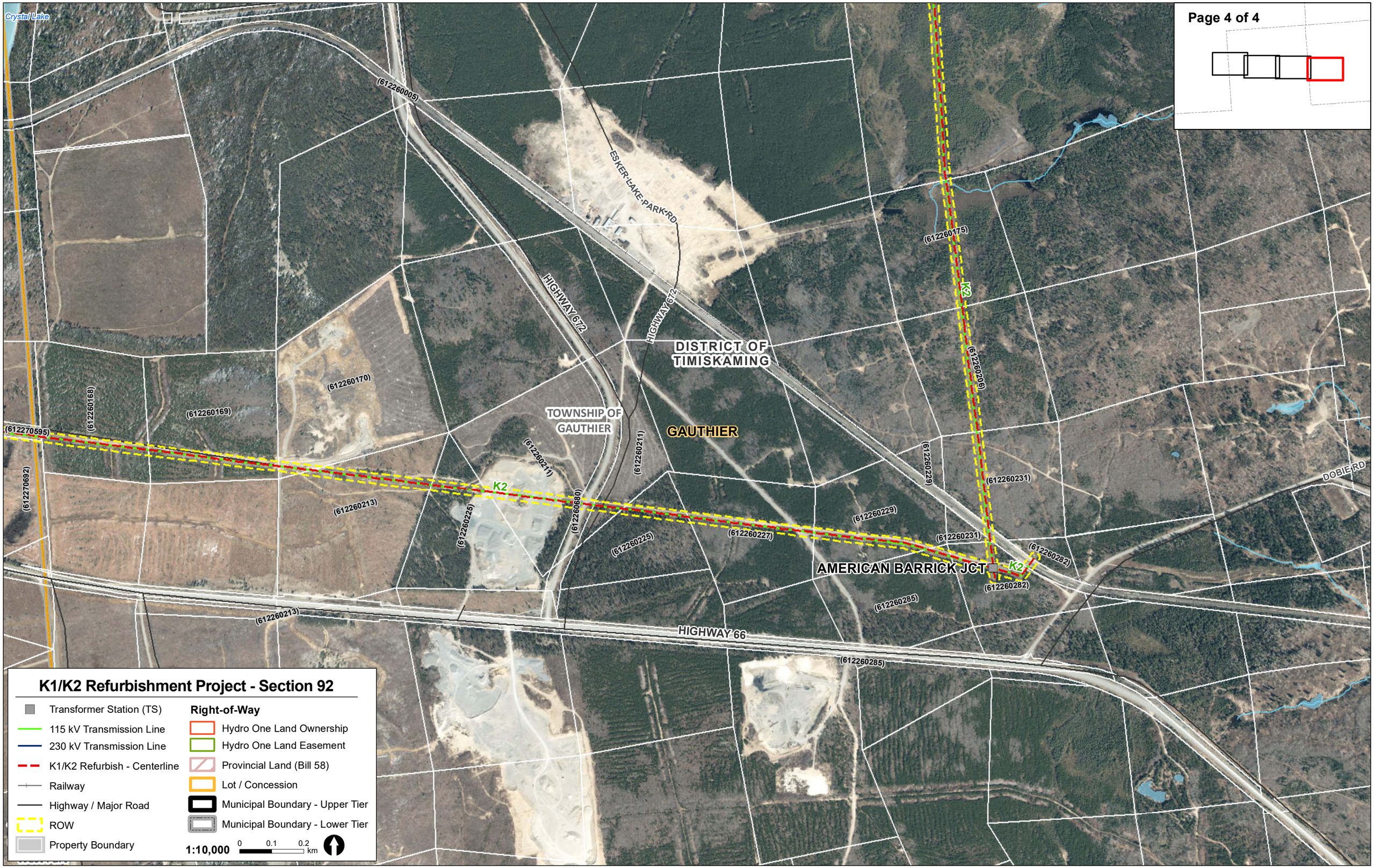
K1/K2 Refurbishment Project - Section 92

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1:10,000 0 0.1 0.2 km



K1/K2 Refurbishment Project - Section 92

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- Municipal Boundary - Upper Tier
- Municipal Boundary - Lower Tier

1:10,000 0 0.1 0.2 km

LIST OF PROPERTIES AND PERMITS ASSOCIATED WITH THE PROJECT ROUTE

HONI ID	PIN (Property Identification Number)	LEGAL DESCRIPTION	TYPE OF PROPERTY	DOES HYDRO ONE REQUIRE NEW OR UPDATED PROPERTY RIGHTS	RIGHTS REQUIRED	Where Agreement is Outstanding - Summary of Negotiations to Date	OWNER(S)
1	61226-0282	PCL 1133 SEC CST; MINING CLAIM L9525 GAUTHIER S/T LT53658 TRANSFERRED UNDER LT82309; S/T LT261179 TRANSFERRED BY LT310095 & LT311162 S/T LT281123;GAUTHIER ; DISTRICT OF TIMISKAMING	Private	no	N/A	N/A	[redacted]
2	61226-0168	PCL 2228 SEC CST; MINING CLAIM L9272 GAUTHIER; GAUTHIER ; DISTRICT OF TIMISKAMING	Private	Yes	Permanent Easement	Outstanding	
3	61226-0169	PCL 1753 SEC CST; MINING CLAIM L8850 GAUTHIER; GAUTHIER ; DISTRICT OF TIMISKAMING	Private	Yes	Permanent Easement	Outstanding	
4	61226-0170	PCL 1834 SEC CST; MINING CLAIM L9273 GAUTHIER; GAUTHIER ; DISTRICT OF TIMISKAMING	Private	Yes	Permanent Easement	Signed, not registered	
5	61226-0211	PCL 2631 SEC CST; MINING CLAIM L9147 GAUTHIER EXCEPT SRO PT 1-3 54R1696; GAUTHIER ; DISTRICT OF TIMISKAMING	Private	Yes	Permanent Easement	Signed, not registered	
6	61226-0213	PCL 3615 SEC CST; MINING CLAIM L9987 GAUTHIER SRO EXCEPT LT120458; GAUTHIER ; DISTRICT OF TIMISKAMING	Private	Yes	Permanent Easement	Signed, not registered	
7	61226-0215	PCL 3611 SEC CST; MINING CLAIM L9494 GAUTHIER (RECORDED AS L24731) SRO EXCEPT LT120458; GAUTHIER ; DISTRICT OF TIMISKAMING	Private	no	N/A	N/A	
8	61226-0217	PCL 7648 SEC CST; MINING CLAIM L9691 GAUTHIER SRO EXCEPT PT AS IN LT79972 EXCEPT LT120458; S/T LT65623; GAUTHIER ; DISTRICT OF TIMISKAMING	Private	Yes	Temporary Access	Outstanding	
9	61226-0225	PCL 5402 SEC CST; MINING CLAIM L27224 GAUTHIER EXCEPT SRO OVER THE HIGHWAY AND TRANSMISSION LINE CROSSING SAID CLAIM EXCEPT SRO PT 3 54R1682; GAUTHIER ; DISTRICT OF TIMISKAMING	Private	no	N/A	N/A	
10	61226-0227	PCL 1135 SEC CST; MINING CLAIM L9527 GAUTHIER EXCEPT MRO AS IN LT280640 S/T LT53658 TRANSFERED BY LT82309 S/T LT281123 ; GAUTHIER ; DISTRICT OF	Private	no	N/A	N/A	
11	61226-0229	PCL 1130 SEC CST; MINING CLAIM L9226 GAUTHIER EXCEPT MRO AS IN LT280640; S/T LT75302 ASSIGNED BY LT240191, LT294772 AMENDED BY LT294771, S/T LT281123	Private	no	N/A	N/A	
12	61226-0285	PCL 1134 SEC CST; MINING CLAIM L9526 GAUTHIER EXCEPT LT122562 EXCEPT MRO AS IN LT281123; S/T LT53658 TRANSFERRED BY LT82309; S/T LT281123; GAUTHIER;DISTRICT OF TIMISKAMING	Private	no	N/A	N/A	
K1	61227-0399	PCL 11151 SEC CST; MINING CLAIM L2454 LEBEL SRO; RESERVING THE SRO ON AND OVER A STRIP OF LAND, ONE CHAIN IN PERPENDICULAR WIDTH ALONG THE SHORE OF GULL LAKE: S/T LT63367 TRANSFERRED BY LT82309; S/T LT137448, LT303106; DISTRICT OF TIMISKAMING ; DISTRICT OF TIMISKAMING	Public	no	N/A	N/A	
K2	61227-0400	PCL 11152 SEC CST; MINING CLAIM L1661 LEBEL BEING LAND AND LAND COVERED WITH WATER OF PT OF GULL LAKE SRO RESERVING THE SRO ON AND OVER A STRIP OF LAND, ONE CHAIN IN PERPENDICULAR WIDTH ALONG THE SHORE OF GULL LAKE WITHIN THE LIMITS OF THE SAID CLAIM: S/T LT63367 TRANSFERRED BY LT82309; DISTRICT OF TIMISKAMING ; DISTRICT OF TIMISKAMING	Public	no	N/A	N/A	
K3	61227-0402	PCL 2957 SEC TIM; MINING CLAIM L2954 LEBEL BEING LAND AND LAND UNDER THE WATER OF THAT PT OF GULL LAKE LYING WITHIN THE LIMITS OF SAID CLAIM AS IN	Public	no	N/A	N/A	
K4	61227-0404	PCL 11148 SEC CST; MINING CLAIM L2029 LEBEL SRO S/T LT47100 TRANSFERRED BY LT82309; DISTRICT OF TIMISKAMING ; DISTRICT OF TIMISKAMING	Public	no	N/A	N/A	
K5	61227-0405	PCL 11149 SEC CST; MINING CLAIM L2030 LEBEL SRO S/T LT47100 TRANSFERRED BY LT82309; DISTRICT OF TIMISKAMING ; DISTRICT OF TIMISKAMING	Public	no	N/A	N/A	
K6	61227-0406	PCL 11153 SEC CST; MINING CLAIM L1904 LEBEL SRO S/T LT63367 TRANSFERRED BY LT82309; DISTRICT OF TIMISKAMING ; DISTRICT OF TIMISKAMING	Public	no	N/A	N/A	
K7	61227-0407	PCL 1174 SEC CST; MINING CLAIM L7420 LEBEL S/T LT44548 TRANSFERRED BY LT82309; S/T LT53657 TRANSFERRED BY LT82972; DISTRICT OF TIMISKAMING ; DISTRICT	Private	no	N/A	N/A	
K8	61227-0408	PCL 1173 SEC CST; MINING CLAIM L7419 LEBEL S/T LT44548 TRANSFERRED BY LT82309; S/T LT53657 TRANSFERRED BY LT82972; DISTRICT OF TIMISKAMING ; DISTRICT	Private	no	N/A	N/A	
K9	61227-0409	PCL 1172 SEC CST; MINING CLAIM L7418 LEBEL S/T LT44548 TRANSFERRED BY LT82309; S/T LT53657 TRANSFERRED BY LT82972; DISTRICT OF TIMISKAMING ; DISTRICT	Private	no	N/A	N/A	
K10	61227-0410	PCL 5050 SEC CST; MINING CLAIM L6483 LEBEL; DISTRICT OF TIMISKAMING ; DISTRICT OF TIMISKAMING	Private	no	N/A	N/A	
K11	61227-0462	PCL 818 SEC CST; MINING CLAIM LS466 LEBEL S/T LT53659 TRANSFERRED BY LT82309; DISTRICT OF TIMISKAMING ; DISTRICT OF TIMISKAMING	Private	no	N/A	N/A	

HONI ID	PIN (Property Identification Number)	LEGAL DESCRIPTION	TYPE OF PROPERTY	DOES HYDRO ONE REQUIRE NEW OR UPDATED PROPERTY RIGHTS	RIGHTS REQUIRED	Where Agreement is Outstanding: Summary of Negotiations to Date	OWNER(S)
K12	61227-0466	PCL 840 SEC CST; MINING CLAIM LS464 LEBEL S/T LT53659 TRANSFERRED BY LT82309; DISTRICT OF TIMISKAMING ; DISTRICT OF TIMISKAMING	Private	no	N/A	N/A	[redacted]
K13	61227-0471	PCL 8979 SEC CST; MINING CLAIM LM71 LEBEL SRO BEING LAND AND LAND UNDER THE WATER OF PT OF A SMALL LAKE WITHIN THE LIMITS OF THIS MINING CLAIM; S/T LT83450 TRANSFERRED BY LT84999; DISTRICT OF TIMISKAMING ; DISTRICT OF TIMISKAMING	Private	Yes	Temporary Access	sent	
K14	61227-0471	PCL 8979 SEC CST; MINING CLAIM LM71 LEBEL SRO BEING LAND AND LAND UNDER THE WATER OF PT OF A SMALL LAKE WITHIN THE LIMITS OF THIS MINING CLAIM; S/T	Private	no	N/A	N/A	
K15	61227-0478	PCL 8978 SEC CST; MINING CLAIM LM70 LEBEL (L7767) SRO BEING LAND AND LAND UNDER THE WATER OF PT OF A SMALL LAKE WITHIN THE LIMITS OF THIS MININGCLAIM EXCEPT LT73569; S/T TO LT83450 TRANSFERRED BY LT84999; DISTRICT OF TIMISKAMING ; DISTRICT OF TIMISKAMING	Private	no	N/A	N/A	
K16	61227-0692	S/T LT53658 TRANSFERRED UNDER LT82309; GAUTHIER ; DISTRICT OF TIMISKAMING	Private	Yes	Permanent Easement	Signed, not registered	
K17	61227-0692	PCL 5973 SEC CST; PT MINING CLAIM L9688 LEBEL; S/T LT65623; DISTRICT OF TIMISKAMING ; DISTRICT OF TIMISKAMING	Private	Yes	Temporary Access	Outstanding	
K18	61228-0997	PCL STREETS & LANES SEC M98TIM; GOVERNMENT RD PL M98TIM TECK SRO EXCEPT PT 36, 47 54R2773; PCL 13175 SEC CST; GOVERNMENT RD PL M15TIM TECK SRO SLY & NLY LIMITS CONFIRMED BY BA2282 & BA2367 AS IN D179 & D181; PCL STREETS & LANES SEC M32TIM; GOVERNMENT RD P	Public	no	N/A	N/A	
K19	61408-0145	PCL 10176 SEC CST; FIRSTLY: PT MINING CLAIM L1823 TECK PT 12 TER484; SECONDLY: PT MINING CLAIM L1822 TECK SRO PT 13 TO 16 TER484; KIRKLAND LAKE ; DISTRICT OF TIMISKAMING	Public	no	N/A	N/A	
K20	61408-0160	PCL 9433 SEC CST; PT MINING CLAIM L2100 TECK SRO PT 2 TER59 EXCEPT PT 1, 2 TER422, PT 1 TO 3 54R1299 S/T PT 3 54R3240 AS IN LT258360, S/T PT 7 54R3240 AS IN LT261759, S/T PT 5, 6 54R3240 AS IN LT267706, S/T PT 1, 2 54R3240 AS IN LT268007; KIRKLAND LAKE ;	Private	no	N/A	N/A	
K21	61408-0161	PCL 10068 SEC CST; PT MINING CLAIM L2100 TECK SRO PT 1 TER422; KIRKLAND LAKE ; DISTRICT OF TIMISKAMING	Public	no	N/A	N/A	
K22	61408-0531	PCL 8736 SEC CST; PT MINING CLAIM L1822 TECK SRO; AS IN LT123597 EXCEPT PT 6 54R1299; KIRKLAND LAKE ; DISTRICT OF TIMISKAMING	Private	no	N/A	N/A	
K23	61408-0532	PCL 7782 SEC CST; PT MINING CLAIM L1831 TECK SRO; AS IN LT99130; PCL 7589 SEC CST PT MINING CLAIM L1831 TECK SRO; AS IN LT94616; S/T LT94616; KIRKLAND LAKE ; DISTRICT OF TIMISKAMING	Public	no	N/A	N/A	
K24	61408-0561	PCL 9439 SEC CST; PT MINING CLAIM L1831 TECK (TC711) SRO PT 1 TER93; EXCEPT PT 3 TER422 & PT 4 54R1299; S/T LT138380 S/T PT 2 54R3470 AS IN LT271697; KIRKLAND LAKE ; DISTRICT OF TIMISKAMING	Private	no	N/A	N/A	
K25	61408-0649	PCL 11194 SEC CST; FIRSTLY: PT MINING CLAIM L1822 TECK PT 4 TER521; SECONDLY: PT MINING CLAIM L1822 TECK SRO PT 15 TO 20 54R1635 S/T PT 21 54R1680 AS IN LT193905; KIRKLAND LAKE ; DISTRICT OF TIMISKAMING	Private	no	N/A	N/A	
K26	61408-0856	PCL 11075 SEC CST; PT MINING CLAIM L1821 LEBEL; PT MINING CLAIM L1823 TECK; PT MINING CLAIM L2374 LEBEL; PT MINING CLAIM L1822 TECK PT 6 TO 9 54R1635; PCL 10177 SEC CST PT MINING CLAIM L-1822 TECK SRO PT 3 TO 5 54R1635; KIRKLAND LAKE ; DISTRICT OF TIMISKA	Public	no	N/A	N/A	
OC1	61408-0889	PCL 11194 SEC CST; SECONDLY: PT MINING CLAIM L1822 TECK PT 13 54R1635; KIRKLAND LAKE ; DISTRICT OF TIMISKAMING	Public	no	N/A	N/A	
OC2	61408-0930	PCL 10068 SEC CST; PT MINING CLAIM L2100 TECK SRO PT 2 TER422; KIRKLAND LAKE ; DISTRICT OF TIMISKAMING	Public	no	N/A	N/A	
OC3	61408-0932	PCL 9439 SEC CST; PT MINING CLAIM L1831 TECK (TC711) SRO PT 2 TER93; EXCEPT PT 5 54R1299; S/T LT138380 S/T PT 4 54R3470 AS IN LT272298, PT 3 54R3470 AS IN LT272524, PT 5 & 6 54R3470 AS IN LT272640; KIRKLAND LAKE ; DISTRICT OF TIMISKAMING	Private	no	N/A	N/A	
OC4	61408-1041	SURFACE RIGHTS ONLY OF: MINING CLAIM L1535 TECK EXCEPT ALL THAT PT OF PL M120TIM LYING WITHIN THE LIMITS OF THE ABOVE MINING CLAIM L1535 & PT 1 TO 4 54R4993, PT 27, 28 54R5446; PT 11 54R5552; T/W PT 2, 54R4993 AS IN LT329553; KIRKLAND LAKE ; DISTRICT OF TIMISKAMING	Municipal	Yes	Temporary Access	sent	

TRANSFER AND GRANT OF EASEMENT

Dated this day of , 2024

B E T W E E N

[FULL LEGAL NAME OF LAND OWNER]

(the "**Transferor**")

- and –

HYDRO ONE NETWORKS INC.

(the "**Transferee**")

WHEREAS:

A. The Transferor is the owner in fee simple and in possession of the Lands described in Schedule "A" attached hereto (the "**Lands**").

B. 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 and the Transferor has agreed to grant the Transferee an easement for such works on the terms and conditions contained herein.

NOW THEREFORE THIS INDENTURE WITNESSETH that in consideration of the payment of *** THOUSAND DOLLARS ($**,***.00) paid by the Transferee to the Transferor (the "Purchase Price"), mutual covenants hereinafter set forth and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged by the parties hereto, the Transferor and Transferee hereto agree as follows:

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 and exclusive rights, easements, 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 on Schedule "A-1" attached hererto (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 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 systems(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 (subject to compensation for merchantable wood values), 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.

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 the 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 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 a minimum of ten 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 the 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 caused 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. THE Transferee may, at its sole discretion, obtain at its 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 interest to the transfer of easement herein so as to place such Rights and easement in first priority on title to the Lands.

4. The Purchase Price shall be paid by the Transferee to the Transferor by uncertified cheque upon the registration of the easement contemplated herein.

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.

[NOTE – IF TRANSFEROR ARE INDIVIDUALS ADD THE FOLLOWING CLAUSE AS #8]

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

IN WITNESS WHEREOF the parties hereto have executed this Grant of Easement.

Signed by the Transferee this day of , 2022.

HYDRO ONE NETWORKS INC.

Per:_____
Name:
Position:

I have authority to bind the Corporation.

Signed by the Transferor this day of , 2022.

[NOTE – INSERT FULL LEGAL NAME OF TRANSFEROR]

Per:_____
Name:
Position:

Per:_____
Name:
Position:

We/I have authority to bind the Corporation

[OR IF TRANSFEROR IS INDIVIDUAL]

SIGNED, SEALED AND DELIVERED
In the presence of)
)
)
)
_____) _____ (seal)
Signature of Witness) Transferor's Signature
)
)
_____) _____ (seal)
Signature of Witness) Transferor's Signature

SIGNED, SEALED AND DELIVERED) Consent Signature & Release of
In the presence of) Transferor's Spouse, if non-owner.
)
)
_____) _____(seal)
Signature of Witness

SCHEDULE "A"

LEGAL DESCRIPTION OF LANDS

[INSERT LEGAL DESCRIPTION OF LANDS]

SCHEDULE "A-1"

EASEMENT LANDS

[Part of Lot •, Concession •, Shown as Parts •, on Reference Plan •R-•••]

Filed: 2026-09-11
EB-2026-0207
Exhibit E-1-1
Attachment 4
Page 1 of 4

THIS AGREEMENT made in duplicate the _____day of _____2021

Between:

XXXXXXXXX

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

--- and ---

HYDRO ONE NETWORKS INC.

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

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

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

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

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

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

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

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

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

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

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

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

TO HONI:

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

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

TO GRANTOR:

XXXXXXXX
XXXXXXXX

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

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

Page 2 of 4

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

SIGNED, SEALED & DELIVERED
In the presence of:

_____
Witness

OWNER(S):

_____
Name:

SIGNED, SEALED & DELIVERED
In the presence of:

_____
Witness

_____
Name:

HYDRO ONE
HST # 870 865 821 RT001

HYDRO ONE NETWORKS INC.

By: _____
Name:
Title:

I have authority to bind the Corporation

Page 3 of 4

SCHEDULE "A"

PROPERTY SKETCH

Page 4 of 4

Damage Claim

THIS MEMORANDUM OF AGREEMENT dated the ____ day of _____, 2025

Between:

XXXX

herein called the "**Claimant**"

- and-

HYDRO ONE NETWORKS INC.

herein called the "**Hydro One**"

Witnesseth:

The Claimant agrees to accept: **XXX DOLLARS ($XX.00)** 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 or will be done by Hydro One during the construction, completion, operation or maintenance of the works of Hydro One constructed on **XXX** which property the Claimant is the legal owner and which damages may be approximately summarized and itemized as:

TOTAL $XX.00

Subject to Approval by Hydro One Networks Inc.

XXX

Per:
_____

Print Name:
Print Title:

We/I have authority to bind the Corporation

SIGNED, SEALED AND DELIVERED
In the presence of)
)
)
_____) _____(seal)
Print Name of Witness Name: ***XXX***

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

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

SYSTEM IMPACT ASSESSMENT

Please refer to **Attachment 1** of this Schedule for the final SIA prepared by the IESO (SIA reference # CAA 2026-EX1325).

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

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Expedited System Impact Assessment Report

Final Report - Public

CAA ID: 2026-EX1325
Project: K1 & K2 Refurbishment
Connection Applicant: Hydro One Networks Inc.

August 27, 2026

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Acknowledgement

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

Disclaimer

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.

Project Description

Hydro One Networks Inc. (HONI) (the "connection applicant" and the "transmitter") is proposing to refurbish approximately 13.7 km of the 115 kV transmission line K2. K2 is a radial circuit emanating from Kirkland Lake Transformer Station (TS). The project also includes the decommissioning of the remaining approximately 1.4 km of the idle 115 kV K1 transmission line.

The project permanent in-service date is Q4 2027.

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.

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

The connection applicant is required to provide "as-built" equipment models and data for the project during the IESO Market Registration process. If the "as-built" equipment data differ materially from the ones used in this assessment, then the IESO may decide that further analysis of the project is required

5. 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.

6. As per Market Manual 1.4: Connection Assessment and Approval, the connection applicant will be required to provide notification to the IESO (Connection.Assessments@ieso.ca) when the project has reached a milestone to deem the project as committed. A common method of delivering this notification is by completing the project status report form (IMO-FORM-1399) A committed project is a project that has demonstrated to the IESO a high probability of being placed into service. Committed projects will be included, together with all projects that are in service, at the time of the SIA, in the basecase assumptions for the evaluation of all projects that are not yet committed, irrespective of the SIA status of those projects. As a result of this inclusion, projects that are not committed could receive additional requirements for connection or may be deemed withdrawn by the IESO.

   To have your project recognized as committed, refer to Market Manual 1.4: Connection Assessment and Approval, Section 3.3, which outlines the criteria for a project to be designated as committed.

Appendix B: Project Data (Confidential)

Appendix C: Technical Assessments (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
facebook.com/OntarioIESO
linkedin.com/company/IESO

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CUSTOMER IMPACT ASSESSMENT

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

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Customer Impact Assessment

Tx Line Refurb. K1/K2, Kirkland Lake TS X American Barrick JCT (Str. 92)

CAA ID: 2026-26
Revision: FINAL
Date: September, 08,2026

Issued By: Transmission System Planning
Hydro One Networks Inc.

Prepared by:

Afreeda Rahman

Afreeda Rahman, M.Eng, P.Eng
Network Management Engineer
Transmission System Planning

Reviewed by:

Alessia Dawes

Alessia Dawes, P.Eng
Sr. Manager, Transmission Planning
Transmission System Planning

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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.

Project Information

Project Name:	Tx Line Refurb. K1/K2, Kirkland Lake TS X American Barrick JCT				
CIA No:	2026-265	Revision:	#0	Date:	August 25, 2026
IESO CAA ID:	2026-EX1325				

Description of the Proposed Project

Hydro One Networks Inc. is proposing to refurbish part of Circuit K2, a 115 kV transmission line between Kirkland Lake Transformer Station (TS) and American Barrick Junction (Structure 92), and the removal of remaining line hardware on the idle Circuit K1 between Kirkland Lake TS and Gull Lake North Junction. The proposed project includes replacement of the existing conductor on approximately 13.7 km of Circuit K2, replacement of deteriorated transmission structures, structure reinforcements, and replacement of associated line components to meet current standards. As part of the project, the remaining conductor and shield wire on the idle K1 circuit will be removed.

The in-service date of the Proposed Project is October 31, 2027. Hydro One has completed system planning assessments for the Proposed Project and determined that the refurbishment is required to address asset condition, reliability, and safety risks associated with aging transmission infrastructure. The proposed project is also subject to Ontario Energy Board (OEB) Section 92 Leave to Construct approval.

Existing Connected Transmission Customers

Hydro One determined prior to conducting this CIA that the following existing Hydro One transmission customers may be impacted by the Proposed Project (collectively, the "**Existing Customers**"):

Station	Customer Name
Northland Power Kirkland Lake Power CGS	Kirkland Lake Power Corp.
Holloway Holt #2 CTS	Agnico Eagle Mines Ltd.
Holloway Holt #3 CTS	Agnico Eagle Mines Ltd.

*A draft copy of this report was provided to affected customers for a 15 days review. No comments were received.

Project Impact

The Proposed Project includes the following:

- Refurbishment of the existing 115 kV transmission circuit K2 through replacement of deteriorated conductors, structures, and associated line components. The replacement conductor will be the 411.4 kcmil ACSR/TW "Simcoe". Furthermore, 7#8 Alumoweld overhead shieldwire will be installed, primarily supported on pole-type transmission structures. Removal of conductor from the remaining section of the idle K1 transmission circuit, fully decommissioning circuit K1.
- Use of temporary facilities to maintain supply to Agnico Eagle Mines during the planned outage required for refurbishment of Circuit K2.
- No new transmission connection points are being established as part of the project.
- No customer reliability degradation is anticipated following completion of the project. The investment is expected to improve reliability by replacing verified deteriorated assets that have exceeded their design life and reducing the risk of unplanned outages.

The project constitutes refurbishment of existing facilities and is not expected to result in material changes to normal transmission system voltages, power flows, or fault levels at affected customer connection points following completion of the work. Any temporary impacts during construction will be managed through planned outages with affected customers and the IESO, and temporary arrangements.

New available fault current for area customers listed in the table above are found in Appendix 1. Customers are required to ensure their facilities are capable of managing the new available fault current.

No significant long-term reliability issues are expected to arise from the Proposed Project. The refurbishment is intended to improve overall transmission system reliability and maintainability for customers supplied from Circuit K2.

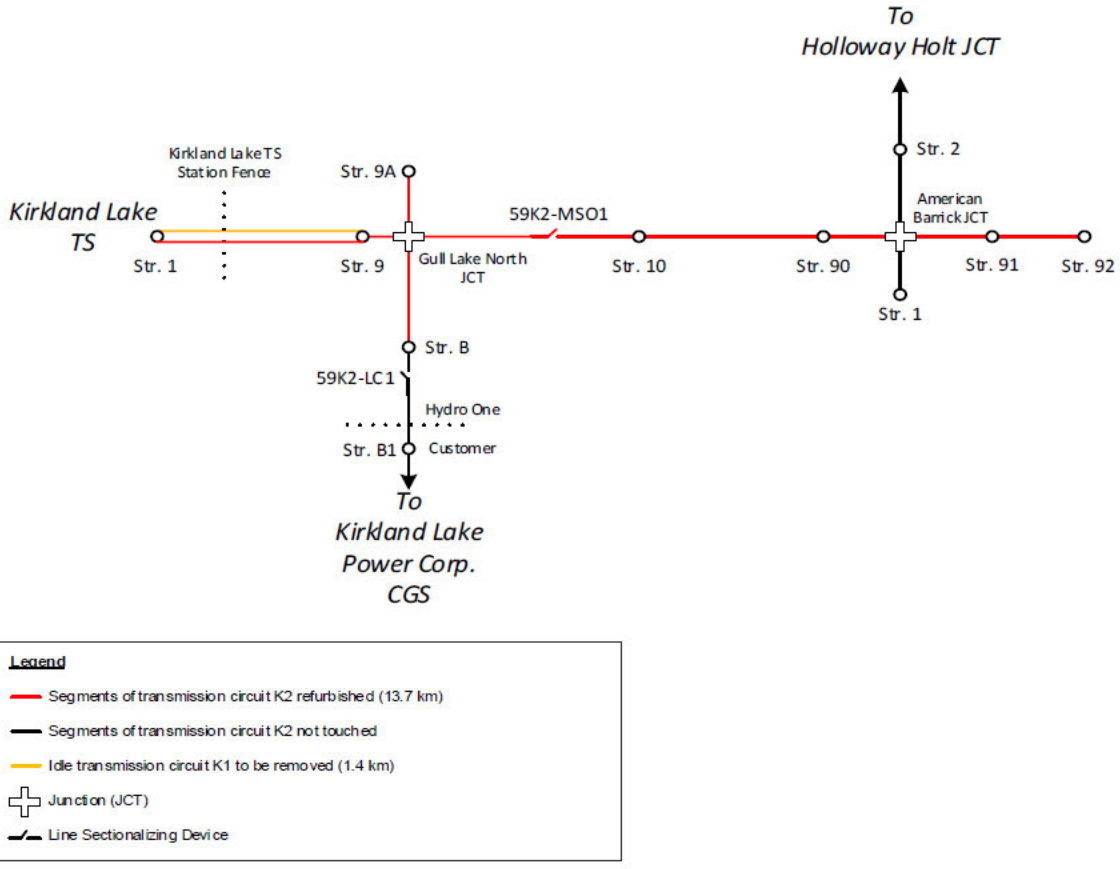
Conclusion

There is no material adverse impact expected on the transmission service received by existing customers following completion of the Proposed Project. The refurbishment of Circuit K2 and removal of remaining K1 hardware will improve asset condition, reduce safety risks, and support continued reliable service to customers supplied from the Kirkland Lake area. The project is subject to OEB Section 92 Leave to Construct approval. Subject to the approval, Hydro One expects the project to be placed in service on October 31, 2027.

Appendix 1 - Short Circuit Levels

		Before Project Completion				After Project Completion			
Station	**kV**	**3Φ Sym (kA)**	**3Φ ASym (kA)**	**1Φ Sym (kA)**	**1Φ ASym (kA)**	**3Φ Sym (kA)**	**3Φ ASym (kA)**	**1Φ Sym (kA)**	**1Φ ASym (kA)**
[redacted]									

Appendix 2 – Single Line Diagram



REGIONAL AND BULK PLANNING

The most recent regional and bulk planning reports relating to this Project are provided in Attachments 1 and 2, as noted below:

Attachment 1: North/East of Sudbury IRRP (April 2023)
Attachment 2: North/East of Sudbury RIP (November 2023)

These reports identify transmission line facility K1/K2 as reaching end-of-life and requiring sustainment to continue reliable operation of the existing transmission system. This need is consistent with the IESO's evidence in support of need provided in **Exhibit B, Tab 3, Schedule 1, Attachment 1**, which further notes that this Project addresses aging transmission infrastructure through refurbishment and decommissioning of obsolete facilities; and does not have any material interdependencies with the North of Sudbury Bulk Plan or associated bulk transmission planning initiatives.

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North & East of Sudbury: Integrated Regional Resource Plan

April 2023

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List of Acronyms

BKF	Breaker Failure
CDM	Conservation and Demand Management
DG	Distributed Generation
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
LTE	Long Term Emergency
LTR	Limited Time Rating
MW	Megawatt
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
TS	Transformer Station

1. Introduction

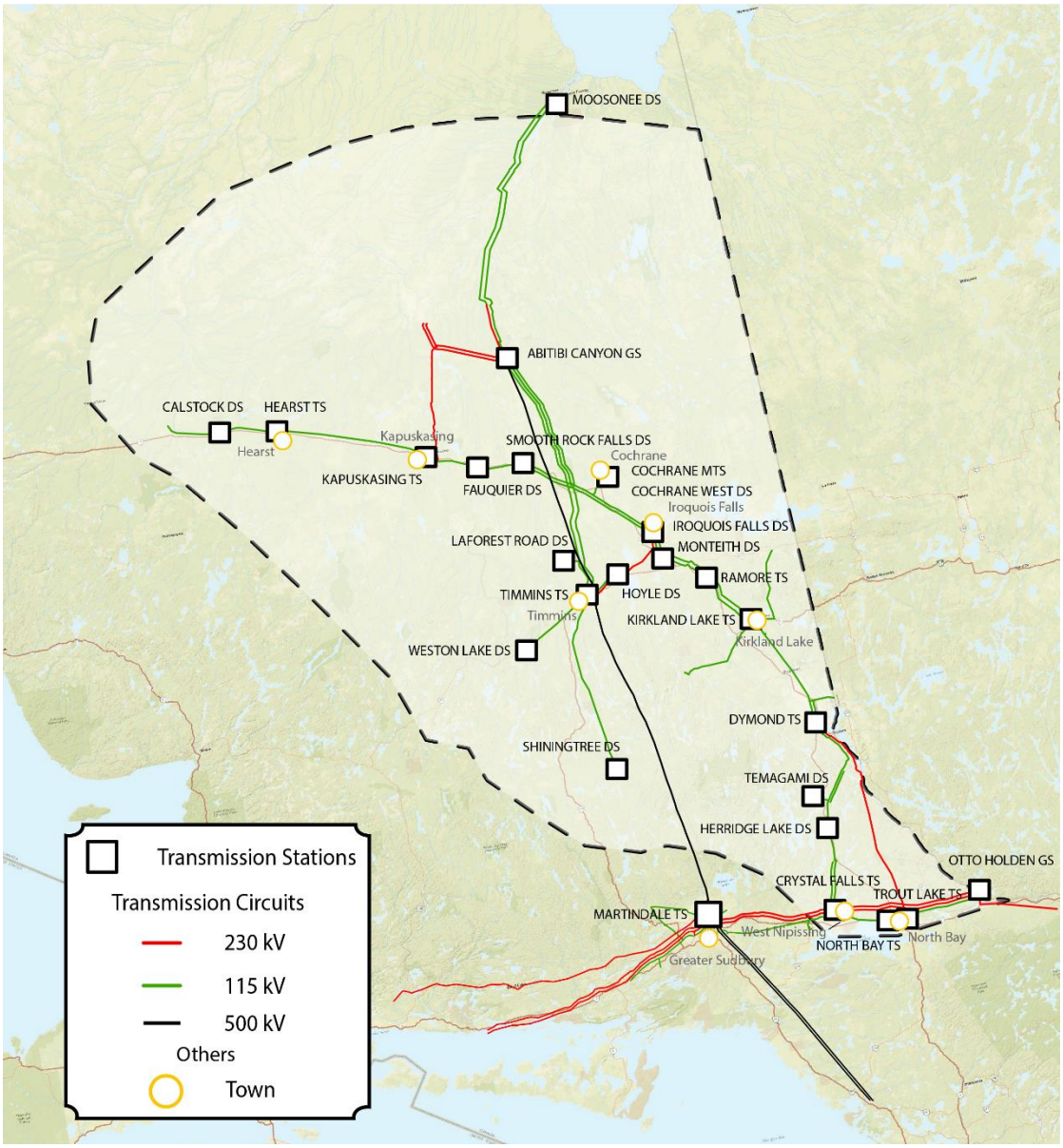
1.1 Overview of Region and Background

The North & East of Sudbury region is a large area supplied by the electricity infrastructure that extends north and east from, but not including, the City of Sudbury. Extending from south of the town of Moosonee in the north to the City of North Bay and town of East Ferris in the south, it includes the towns of Hearst, Kapuskasing, Smooth Rock Falls, Cochrane, Foleyet, Iroquois Falls, Kirkland Lake and Englehart. It also includes the townships of Black River Matheson and East Ferris, the cities of North Bay, Temiskaming Shores and Timmins and the municipality of West Nipissing. The North & East of Sudbury region is also home to First Nation communities listed in Table 1. A map of the area indicating the location of transmission assets is found in Figure 1.

Table 1 | List of First Nation Communities in the North & East of Sudbury Region

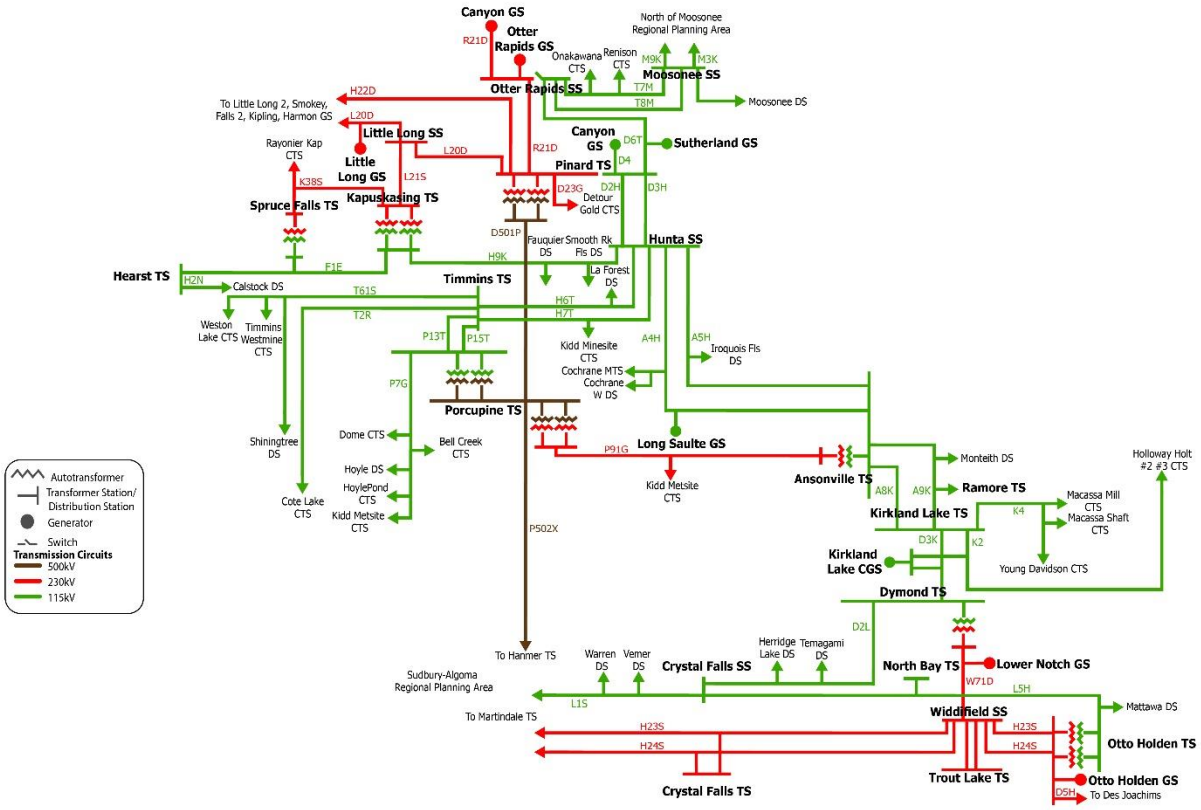
Constance Lake First Nation
Flying Post First Nation
Matachewan First Nation
Mattagami First Nation
Missanabie Cree First Nation
Moose Cree First Nation
Nipissing First Nation
Taykwa Tagamou First Nation
Temagami First Nation
Wahgoshig First Nation
Wahnapitae First Nation

Figure 1 | Map of the North & East of Sudbury Area



Note that, for regional electricity planning purposes, the region is defined by electrical infrastructure rather than geography. The region is supplied through 500/230 kV autotransformers at Porcupine TS and Pinard TS and encompasses the 230 kV circuits east of Martindale TS in the west to Otto Holden TS in the east as well as the 500 kV circuits from Hammer TS to Pinard TS and the 115 kV sub-systems in between. For clarity, the North & East of Sudbury region does not include the area north of Moosonee. There are non-synchronous interconnections with Quebec at Dymond TS and Otto Holden TS. At Dymond TS, intertie circuit D4Z at Dymond TS can deliver imports from generation located in Quebec, and industrial load in Quebec (i.e., a paper plant in Témiscaming, Quebec) can be supplied radially via the 115 kV intertie circuit H4Z. This Quebec load is not part of this study as it can also be supplied from Quebec. A single line diagram of the electricity infrastructure in the region is shown in Figure 2.

Figure 2 | Electricity Infrastructure in the North & East of Sudbury Region



Demand in this region is winter peaking and a large share of this demand is high electricity intensity industries, primarily mining and forestry operations. Demand growth in this area is primarily forecast to be in the mining sector, where project development is highly dependent on factors such as commodity prices and access to financing.

The region has over 2,600 MW of generation, including numerous hydroelectric facilities, solar, gas and bio-fuel facilities. The lead transmitter for the region is Hydro One Networks Inc. and the local distribution companies (LDCs) are North Bay Hydro, Northern Ontario Wires Inc., Hearst Power Distribution Co., Greater Sudbury Hydro, and Hydro One Networks Inc. (Distribution).

2. The Integrated Regional Resource Plan

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

Table 2 summarizes the needs identified in this study and the IRRP's recommendations to address them.

Table 2 | Summary of Needs and Recommendations for North & East of Sudbury IRRP

No.	Need Description	Recommendation	Need Date
1	Station Capacity at Ramore TS	Load growth at Ramore TS will be monitored and revisited in the next cycle of regional planning	2033
2	Voltage control issues with existing capacitors at Dymond TS	Hydro One to investigate options to improve operability of existing capacitors in the upcoming RIP	2030
3	Voltage control issues in the Kirkland Lake area	Hydro One to investigate options of adding reactive devices in the Kirkland Lake area in the upcoming RIP	2030
4	Voltage control issues at Ansonville, Hunta, Kapuskasing Area	Various recommendations, including a new RAS, replacing failed equipment and additional voltage support	Near to Mid-term
5	Thermal overload of circuit D3K upon loss of A8K or A9K when its companion is out of service	The new Kirkland Lake RAS installed in 2022 addresses this issue. Additional load in the area beyond the current forecast will require further study	2030
6	A4H/A5H End-of-Life Need	Hydro One to proceed with plans to replace the affected circuit sections with a like-for-like replacement	2027

No.	Need Description	Recommendation	Need Date
7	D2H/D3H End-of-Life Need	Hydro One to proceed with plans to replace the affected circuit sections with a like-for-like replacement	2026
8	ORTAC load security criteria not met for 500 kV circuit outages	Partially addressed by the recent Northeast Bulk Plan. An update to this plan is recommended should significant new resources and/or load connect to the North & East of Sudbury region.	Existing Need
9	Difficulty supplying loads during planned outages to circuit D501P	Study this need as part of the next bulk system plan for Northeast Ontario in combination with other drivers of system expansion as they develop	Existing Need

3. Development of the IRRP

3.1 The Regional Planning Process

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

The process consists of four main components:

1. A Needs Assessment, led by the lead transmitter in the region, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
2. A Scoping Assessment, led by the IESO, which identifies the most appropriate planning approach to address identified needs;
3. An IRRP, also led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
4. A Regional Infrastructure Plan (RIP), led by the lead transmitter, which provides further details on recommended wires solutions.

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

In addition to regional planning, there are also bulk system planning and distribution network system planning processes. Bulk system planning typically considers the 230 kV and 500 kV network and examines province-wide system issues, and distribution network planning considers the adequacy and reliability of the distribution system(s) supplying customers within a particular community. Regional planning sits between bulk planning and distribution planning and focuses on ensuring that an area can be reliably supplied given forecast demand growth and other developments in a region.

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

3.2 North & East of Sudbury and IRRP Development

The process to develop the North & East of Sudbury IRRP was initiated following the publication of Hydro One's North & East of Sudbury Needs Assessment report in May 2021 and the IESO's Scoping Assessment Outcome report in August 2021. The Scoping Assessment report recommended that the needs identified for the North & East of Sudbury region be considered through an IRRP using a coordinated regional approach. The Scoping Assessment Working Group, consisting of the IESO, the transmitter and the LDCs in the region, was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options and recommend solutions for the North & East of Sudbury region.

4. Background and Study Scope

This is the second cycle of regional planning for the North & East of Sudbury region. During the first cycle of regional planning, a Needs Assessment was conducted in April 2016 that was led by the transmitter, Hydro One Networks Inc. Transmission. After reviewing the needs identified in the report, the Technical Working Group recommended that further regional coordination was not required and a Regional Infrastructure Plan, also led by the transmitter, was published in April 2017.

This cycle of regional planning started with a Needs Assessment published by Hydro One in May 2021 which identified a number of needs requiring further regional coordination. This was followed by a Scoping Assessment process which was finalized in August 2021. The Scoping Assessment Outcome report recommended that an IRRP be initiated. This report is the outcome of the IRRP process and presents an integrated regional electricity plan for the next 20-year period from 2021 to 2040.

4.1 Study Scope

This IRRP was prepared by the IESO on behalf of the Technical Working Group and recommends options to meet the electricity needs of the North & East of Sudbury region of the study period with a focus on providing an adequate, reliable supply to support community growth. The plan includes consideration of forecast electricity demand growth, conservation and demand management (CDM), distributed generation (DG), transmission and distribution system capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system. The full scope of the study can be found in Appendix D.

4.1.1 Planned Projects Considered in the IRRP

The following projects were already planned or underway when the IRRP was initiated, and were assumed to be in service in developing the IRRP assumptions.

1. Ansonville to Kirkland Lake Line Upgrade: Upgrading of end-of-life circuits A8K and A9K from 230 A to 550 A capacity.
2. Kapuskasing Area Reinforcement: Upgrading two sections of circuit H9K (from Spruce Falls JCT to Carmichael Falls JCT and Gemini Smooth Rock Falls JCT to H9K Structure 127A JCT) to higher 550 A capacity.

The North & East of Sudbury IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast;
- Examining the capacity 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, and considered the findings and recommendations made through other planning processes being carried out in parallel, namely the Northeast Bulk Plan;
- 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 Hydro One;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible wires alternatives (e.g., transmission and/or distribution) and non-wires alternatives (e.g., energy efficiency, local generation, storage and other distributed energy resources);
- Engaging with the community on needs, findings and possible alternatives;
- Evaluating alternatives to address near and long-term needs; and
- Communicating findings, conclusions and recommendation within a detailed plan.

4.2 Coordination with Bulk Planning Initiatives

In addition to the Regional Planning activities being undertaking for the North & East of Sudbury region, a number of Bulk Planning initiatives have recently been undertaken or are currently underway with the potential to affect assumptions and outcomes in the area. Two initiatives in particular, the Northeast Bulk Plan, and the Northern Voltage Study, have implications for the current Regional Planning process, with further details described below.

4.2.1 Northeast Bulk Planning Study

A bulk planning study was initiated for northeastern Ontario in 2021 that was completed in October 2022. This study examined a number of needs in the area, and paid particular focus to improving supply security for growing demand in and around the cities of Sault Ste. Marie and Timmins. Compared to a regional planning focus, the goal of the bulk study was to ensure sufficient power could be delivered to load centres, but did not include final customer delivery, including step down or local voltage needs.

Recommendations made during this study were treated as input assumptions for the current North & East of Sudbury IRRP, and were assumed to come into service at their target date. The Northeast Bulk Plan recommended the following system reinforcements.

1. A new ~260 km single circuit 230 kV transmission line (built to 500 kV standards) between Wawa Transformer Station (TS) and Porcupine TS to be in-service in 2030;
2. A new ~205 km single circuit 500 kV transmission line between Mississagi TS and Hanmer TS and addition of two new autotransformers at Mississagi TS to be in-service in 2029; and
3. A new ~75 km double circuit 230 kV transmission line between Mississagi TS and Third Line TS to be in-service in 2029.

Additional information on this study is available on the IESO website, here.

4.2.2 Northern Voltage Study

The Northern Voltage Study was initiated recognizing that the voltage profile across northern Ontario was set to change with system expansions planned in northeast Ontario (i.e., the Northeast Bulk Plan recommendations) as well as in northwestern Ontario (i.e., the East West Tie expansion, the Waasigan line and the Wataynikaneyap line). The study examines reactive requirements associated with these new lines and the resulting changes to the voltage profile. In addition, it addresses existing challenges managing system voltages in northern Ontario as reported by the IESO's control room operators and identifies requirements to improve operability.

Although the scope of the Northern Voltage study is much wider than the North & East of Sudbury IRRP, and tends to focus on contingencies and operational concerns outside the typical scope of Regional Planning, the potential for needs and recommended solutions from one study to affect system assumptions for the other required that these two studies be carried out in a coordinated manner. Since bulk system reactive requirements were being studied through the Northern Voltage Study, the North & East of Sudbury IRRP did not address these issues and instead focused on identifying and addressing localized voltage concerns in the region.

5. Electricity Demand Forecast

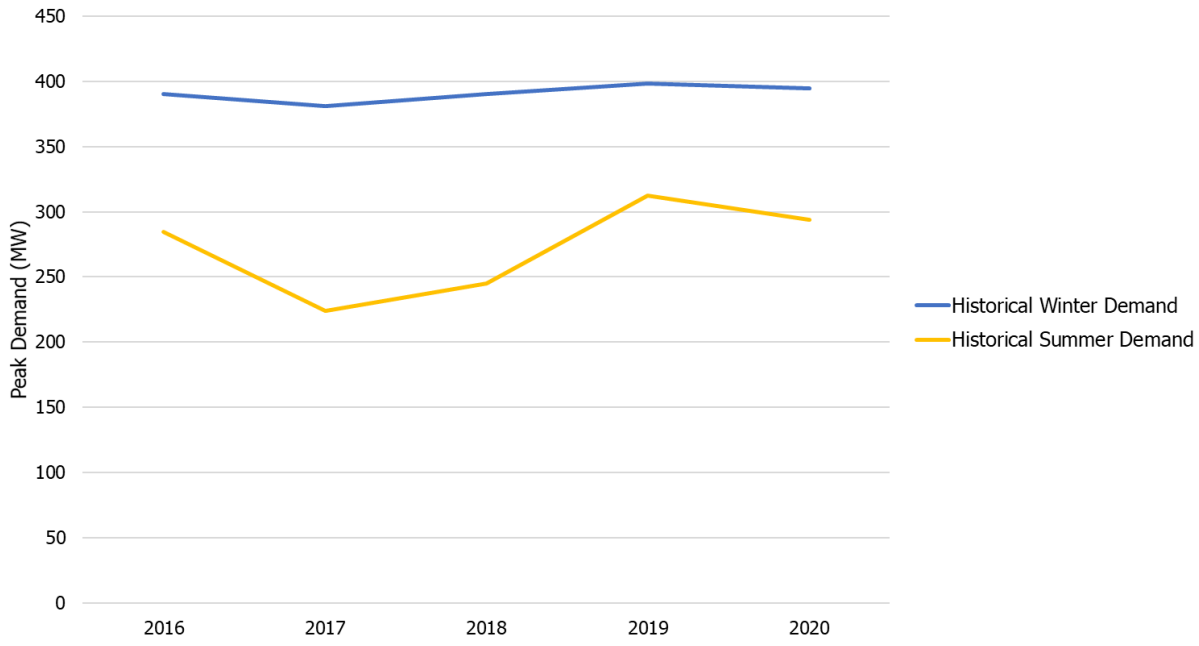
Regional planning is driven in large part by the need to meet peak electricity demand requirements in the region under study. This section describes the specific details of the development of the demand forecast for the North & East of Sudbury region, which is comprised of an LDC demand forecast as well as a forecast of transmission-connected loads (i.e., large industrial customers). It highlights the assumptions made for peak demand forecasts including the contribution of CDM and distributed generation to reducing peak demand. The resulting net demand forecast, termed the planning forecast, is used in assessing the electricity needs of the area over the planning horizon.

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

5.1 Historical LDC Electricity Demand

Historical LDC electricity demand in the North & East of Sudbury region is primarily driven by residential and commercial customers (with the exception of Ramore TS and North Bay TS which are largely industrial driven) and demand typically peaks during the winter months. Winter demand is also typically much higher than summer demand as seen in Figure 3 below.

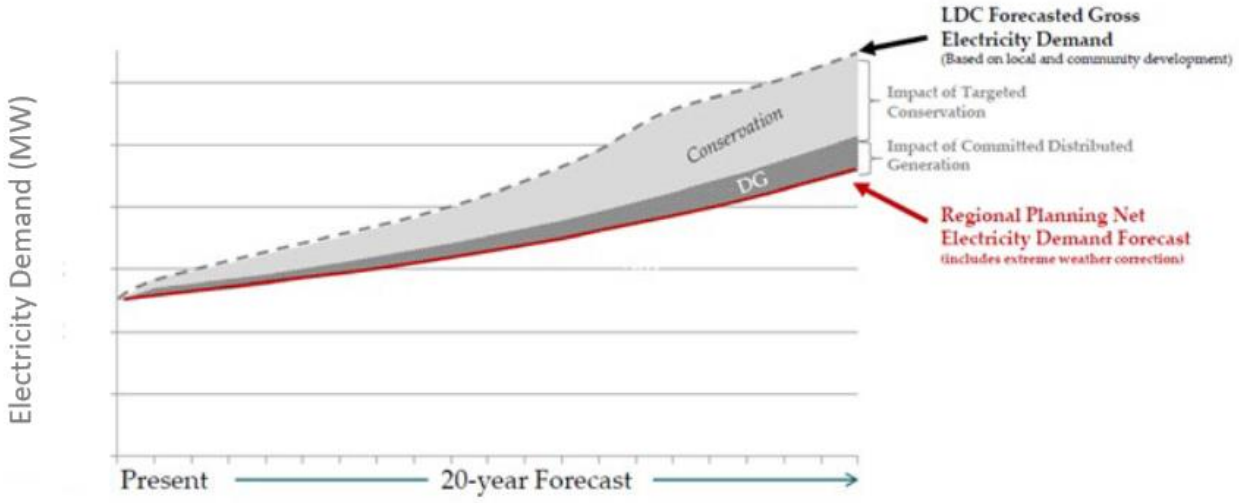
Figure 3 | Historical LDC Winter and Summer Peak Demand for the North & East of Sudbury Region



5.2 LDC Demand Forecast Methodology

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

Figure 4 | Illustrative Development of the Demand Forecast



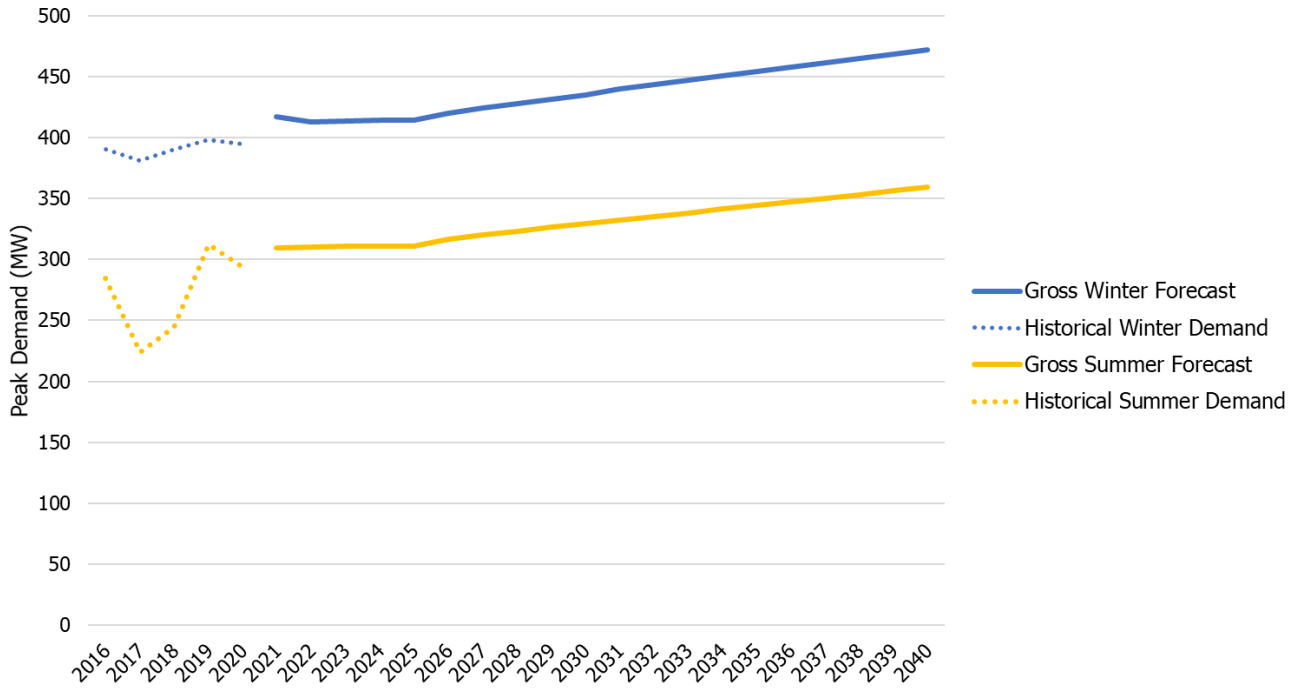
5.3 LDC Gross Demand Forecast

Gross demand forecasts were submitted by each participating LDC in the North & East of Sudbury region. LDCs have knowledgeable insights into future local demand growth and drivers due to their direct involvement with their customers. These insights include future connection applications and knowledge of typical electrical demand trends for different types of customer groups.

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

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

Figure 5 | Gross Winter and Summer LDC Forecast for the North & East of Sudbury Region



5.3.1 Contribution of Conservation to the LDC Demand Forecast

Conservation and demand management is a clean and cost-effective resource that helps meet Ontario's electricity needs and has been an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and standards amendments as well as CDM program-related activities. These approaches complement each other to maximize conservation results.

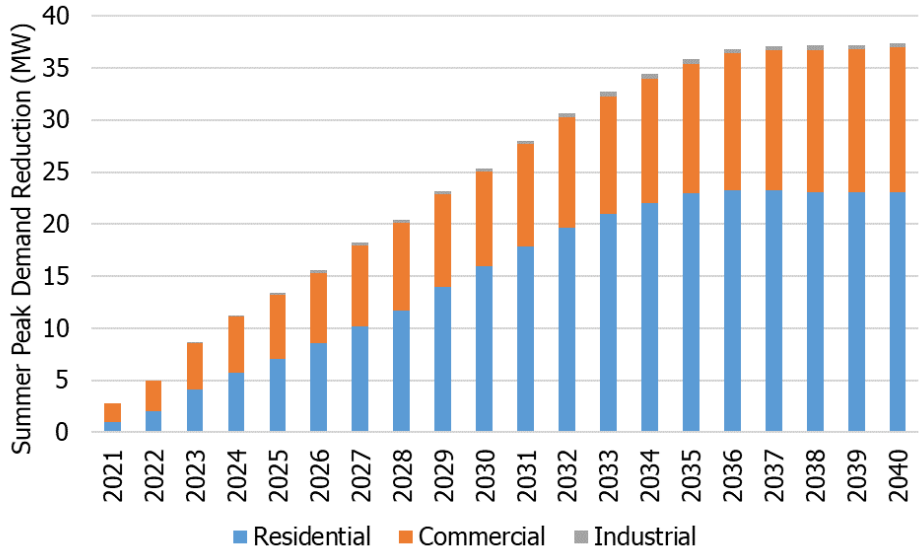
The estimate of demand reduction due to codes and standards is based on expected improvement in the codes for new and renovated buildings and through regulation of minimum efficiency standards for equipment used by specified categories of consumers (i.e. residential, commercial and industrial consumers).

The estimates of demand reduction due to program-related activities account for the provincial 2021-2024 CDM Framework, federal programs that result in electricity savings in Ontario, and assumptions regarding continuing provincial CDM programming after 2024.

CDM savings have been applied to the North & East of Sudbury region's LDC gross peak demand forecast for median weather, along with DG (as described in Section 5.3.2) to determine the net peak demand for the region. This takes into account both 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.

Figure 6 shows the estimated total yearly reduction to the LDC demand forecast due to conservation from codes, standards and CDM programs for each of the residential, commercial and industrial consumers. Additional details are provided in Appendix B.3.1.

Figure 6 | Estimated total yearly reduction to the LDC demand forecast due to conservation



5.3.2 Contribution of Distributed Generation to LDC Demand Forecast

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

The following load supply stations included in this IRRP have embedded DG resources:

- Crystal Falls TS
- Kapuskasing TS
- Ramore TS
- Timmins TS
- Dymond TS
- Trout Lake TS

The effective winter capacity of DG across the region totaled 16 MW in 2022. The expected annual peak demand contribution of contracted DG in the North & East of Sudbury region and capacity contribution factors can be found in Appendix B.

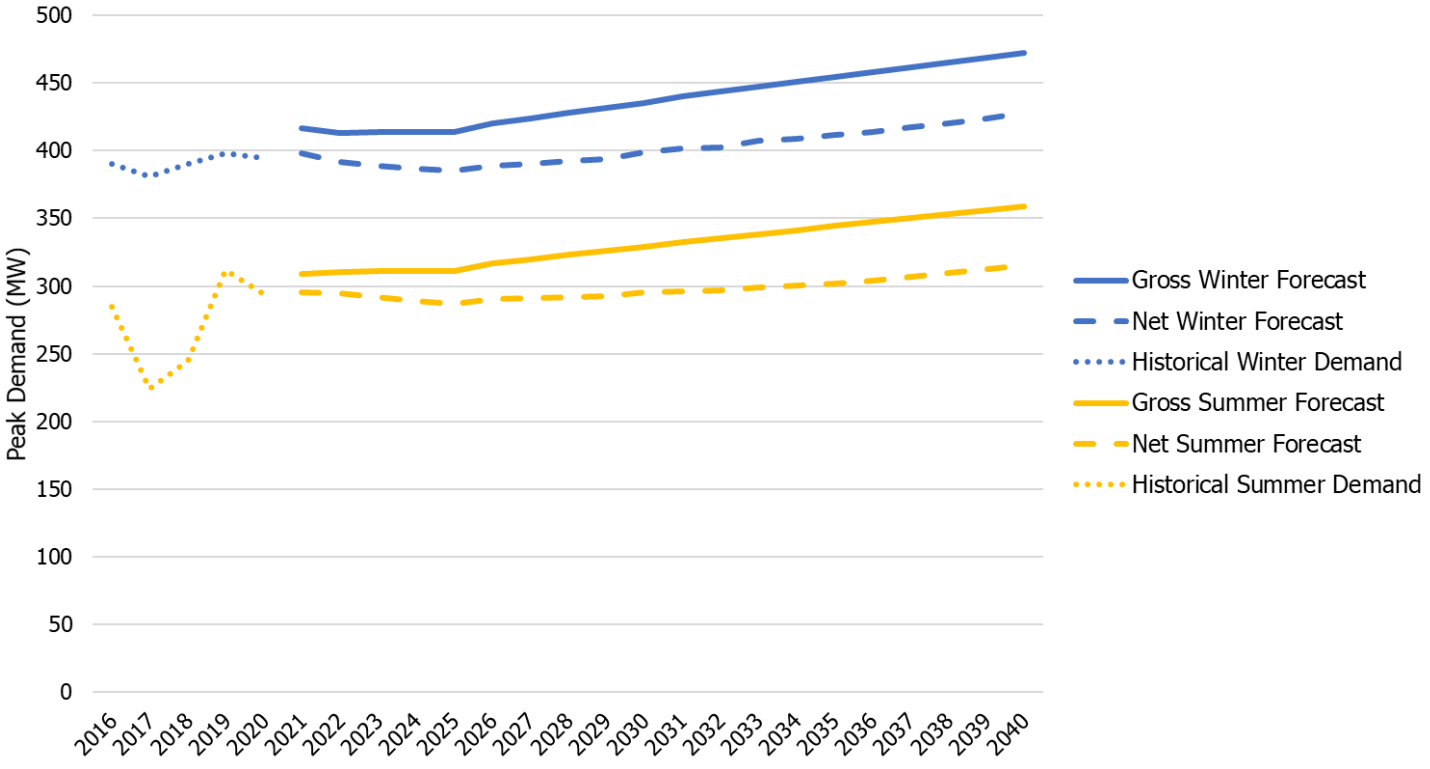
5.3.3 LDC Net Extreme Weather Planning Forecast

The net extreme weather planning forecast, also known as the "planning" forecast, is the coincident peak demand forecast for the region and is used to carry out system studies for identifying potential needs in the North & East of Sudbury region. This forecast is created in three steps:

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

The gross and net extreme weather coincident forecasts for the North & East of Sudbury region are shown in Figure 7 below for summer and winter.

Figure 7 | Extreme Weather Gross and Net Winter and Summer LDC Forecasts for the North & East of Sudbury Region



5.4 Transmission-Connected Forecast

Forecast demand growth among transmission-connected customers in the North & East of Sudbury area primarily consists of new or expanded mining projects and associated industrial processes (e.g. refining). The transmission-connected forecast represents the most up to date information on the timing, size and likelihood of these mining customers either increasing their existing demand or connecting to the system as a new customer.

The mining forecast is project-based and built from the bottom up based on known mining exploration or projects collected from proponents, industry publications, utility companies, and government. Each project is assigned one of four "likelihood" factors ranging from "most likely" to "least likely" that represents the probability of its electricity demand materializing to enable the creation of scenarios that represent different potential future outcomes.

A project's likelihood is informed by factors such as the reliability of available data sources, development stage of the project, project timing, and permitting information. The IESO also incorporates input from the Ministry of Mines on the forecast and likelihood factors. The mining forecast scenarios are summarized in Table 3 below.

Table 3 | Mining Forecast Scenario Descriptions

Scenario	Description
Low	- Conservative scenario including only existing mining projects and their extension/expansion/retirement plans - The full demand forecast for all existing mining projects is included
Reference	- Includes all demand in the low scenario plus demand forecast from projects classified as "most likely" and "likely" discounted according to their likelihood classification: o "Most likely" project forecasts are not discounted o "Likely" project forecasts discounted to 80% of their full project demand - Aligned with 2021 Annual Planning Outlook[1] reference scenario
High	- Includes all known mining projects with each project's demand forecast discounted according to their likelihood classification: o "Most likely" project forecasts are not discounted o "Likely" project forecasts discounted to 80% of their full project demand o "Less likely" project forecasts discounted to 50% of their full project demand o "Least likely" project forecasts discounted to 20% of their full project demand - Aligned with 2021 Annual Planning Outlook high scenario

The transmission-connected forecast for the North & East of Sudbury area is comparable in size to the LDC forecast. However, transmission-connected customers tend to have a more noticeable impact on the transmission system as they tend to have a flat demand profile (i.e., 24/7 operation) and are large loads. Large step increases in demand from new or expanded transmission-connected customers can stress the system more quickly than growth in LDC load which tends to have a more predictable and slower growth rate as seen in Figure 7 above. Therefore, these transmission-connected customers are more likely to drive system enhancements to support their growth/new connections. The transmission-connected forecast is shown in Figure 8 below.

[1] The Annual Planning Outlook forecasts electricity demand, assesses the reliability of the electricity system, identifies capacity and energy needs, and explores the province's ability to meet them. The latest Annual Planning Outlook is available on the IESO's Planning and Forecasting webpage.

Figure 8 | Transmission-Connected Forecast



5.5 Load Profiling

In addition to the annual peak demand forecast, hourly load profiles (8,760 hours per year over a 20 year forecast horizon) for a station with an identified capacity need were developed to characterize these 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 impacts (e.g. extreme weather events like ice storms or heat waves). The profiles are then scaled to match the annual peak demand forecast for each year. These profiles are used to quantify the magnitude, frequency and duration of needs to better evaluate the suitability of non-wires alternatives options.

Additional load profile details including summary tables and hourly heat maps for each need (where appropriate) can be found in Section 6.2.1.1 and Appendix B.

6. Electricity System Needs

6.1 Needs Assessment Methodology

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

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day LTR of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be 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 load meeting capability (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 simulation analysis. An area's LMC can be limited by the thermal ratings of the equipment, or the voltage levels/changes following a contingency in the area.
- **End-of-life Asset Refurbishment Needs** describe the needs identified by the transmitter with consideration to a variety of factors such as asset age, the asset's expected service life, risk associated with the failure of the asset and its condition. Replacement needs identified in the near-and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium-to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage. 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.

In addition, for the North & East of Sudbury IRRP, several existing operational needs were identified through discussion with the IESO's control room operators and outage planning staff. These needs include localized voltage control issues and difficulty planning 500 kV outages while still maintaining supply to customers in the area.

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

6.2 Needs Identified

Table 4 below summarizes the needs identified by the North & East of Sudbury IRRP. Some needs previously identified (e.g. Kirkland Lake TS capacity need in 2040, higher than standard operating voltages in the Porcupine to Hunta area) were deferred to the next round of regional planning. For Kirkland Lake TS, the uncertainty regarding certain mining loads and the long term nature of the need means that the need could be deferred. The high operating voltages from Porcupine to Hunta requires more coordination and discussion with existing customers whose equipment are designed to operate at these high voltages. Furthermore, the North of Moosonee region will need to be studied to see if lower operating voltages can be accommodated. Such an activity is outside the scope of this regional plan and is suggested to be addressed in the North of Moosonee regional planning process.

Table 4 | Summary of Needs for North & East of Sudbury IRRP

No.	Need Description	Need Date
1	Station Capacity at Ramore TS	2033
2	Voltage control issues with existing capacitors at Dymond TS	2030
3	Voltage control issues in the Kirkland Lake area	2030
4	Voltage control issues at Ansonville, Hunta, Kapuskasing Area	Near to Mid-term
5	Thermal overload of circuit D3K upon loss of A8K or A9K when its companion is out of service	2030
6	A4H/A5H End-of-Life Need	2027
7	D2H/D3H End-of-Life Need	2026
8	ORTAC load security criteria not met for 500 kV circuit outages	Existing Need
9	Difficulty supplying loads during planned outages to circuit D501P	Existing Need

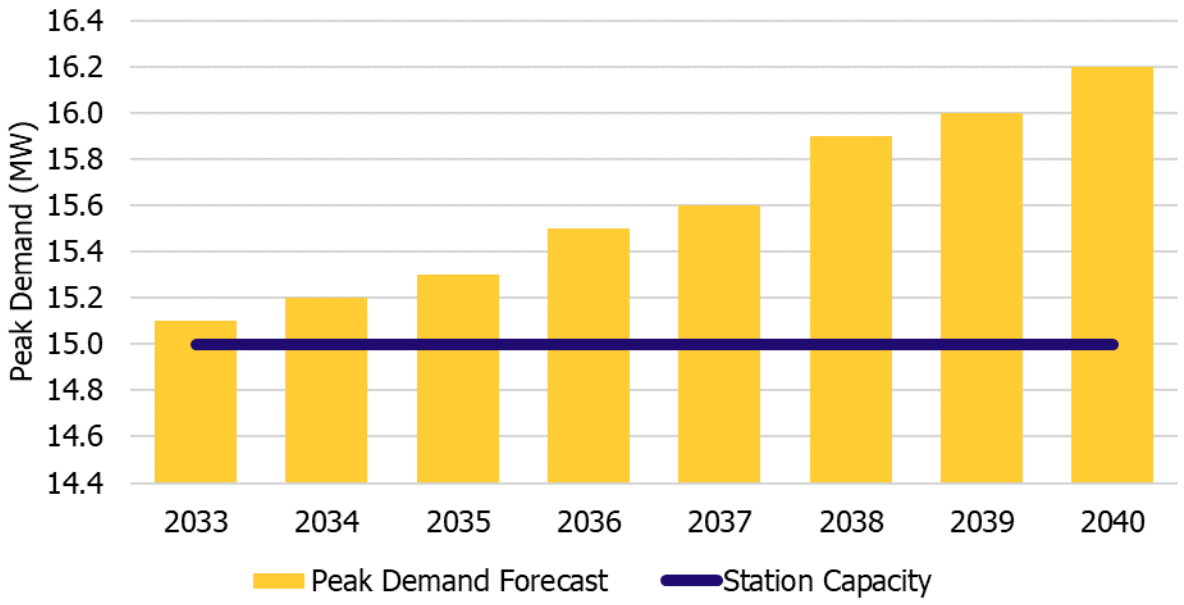
6.2.1 Station Capacity Needs

6.2.1.1 Ramore TS

Winter peak demand growth at Ramore TS is expected to exceed the station's capacity in 2033. The non-coincident winter peak forecast for Ramore TS is found in Figure 9 below.

Note that load growth in the Ramore TS service area is expected to be primarily driven by new or expanding industrial customers. These types of loads are inherently more difficult to forecast beyond the near term as growth tends to occur in large blocks if/when economic conditions support investment. As a result, the timelines associated with this need are understood to be beyond the near term (when actual applications for connection would already be known), but may be triggered with relatively short lead time thereafter. Potential options to address this need should be evaluated to ensure any necessary upgrades can be triggered with minimal planning lead time when required, as opposed to working towards a firm anticipated in-service date of 2033.

Figure 9 | Ramore TS Winter Peak Forecast



6.2.2 Supply Capacity Needs

6.2.2.1 Dymond TS Voltage Control

IESO control room operators report existing operational issues associated with the two existing capacitors at Dymond TS. They observe that the two capacitors at Dymond TS cannot be placed into service without exceeded the maximum voltage allowed by IESO Market Rules, an indication that they are too large for the area under current system conditions.[2] They also note that the existing Dymond capacitor switching scheme is a manual scheme with no telemetered status to either the IESO's or Hydro One's control rooms. This means that staff must be called out to the station to confirm or update the status of the scheme, and this can cause delays in responding to outages.

System studies show that a failure of the AL3 breaker at Dymond TS to open when called upon to clear a fault can cause voltage decline at Dymond TS, beginning in 2030. Voltage decline usually occurs when there is a large amount of load and/or lack of available reactive power resources (e.g. shunt capacitors) to provide voltage support. There are currently capacitors at Dymond TS that may address this issue. However, operators have found the current capacitors are too large to use to prevent this voltage depression.

6.2.2.2 Kirkland Lake Area Voltage Control

IESO system operators report difficulties maintaining minimum operating voltages in the Kirkland Lake area under outage conditions with recent demand growth and changes to the operation of local gas generation. System studies confirm that concurrent outages to the Kirkland Lake SVC and all units at the Northland Power Kirkland Lake Generating Station cause voltage decline issues in the Kirkland Lake area. Specifically, minimum voltages cannot be maintained at the end of the radial K2 circuit.

[2] It is likely that when these capacitors were designed, they were sized appropriately for the area but changing system conditions over time have led to them being oversized.

6.2.2.3 Ansonville, Hunta, Kapuskasing Area Voltage Control

There are post contingency voltage control issues at Ansonville TS, Kapuskasing TS and Hunta TS for the loss of Ansonville T2 and Canyon Units.

6.2.2.4 D3K Thermal Overload

D3K is a 115 kV circuit that supplies Kirkland Lake TS from the south. Kirkland Lake TS is also supplied from the north by two 115 kV circuits, A8K and A9K. Upon the loss of either A8K or A9K when its companion is on outage, Kirkland Lake is supplied radially from the south via D3K. With forecast demand growth in the area, this outage condition will cause D3K to be thermally overloaded (102% of LTE) beginning in 2030.

6.2.3 End-of-Life Refurbishment Needs

6.2.3.1 A4H/A5H End-of-Life

Conductors on sections of A4H and A5H, namely the 25 km sections from Tunis JCT to Fournier JCT, are reaching end-of-life and are planned for replacement in 2027. This IRRP investigated whether there are other needs in the region for which there is an opportunity to right-size the ampacity of the conductors.

6.2.3.2 D2H/D3H End-of-Life

Conductors on sections of D2H and D3H, namely the 90 km sections of these circuits from Pinard TS to Hunta SS, are reaching end-of-life and are planned for replacement in 2026. This IRRP investigated whether are other needs in the region for which there is an opportunity to right-size the ampacity of the conductors.

6.2.4 Load Security and Restoration Needs

6.2.4.1 500 kV Load Security

The North & East of Sudbury region is supplied by two 500 kV circuits, P502X from Hanmer TS to Porcupine TS and D501P from Porcupine TS to Pinard TS, that are operated in parallel with a relatively weak 115 kV system. The system was developed not only to supply loads in the region, but also to integrate a substantial amount of hydroelectric generation on the Moose River which, when generating at full output result in substantial southbound flows on the 500 kV system. The need to respect the loss of either of these 500 kV circuits significantly limits the capability of this system because the 115 kV path cannot handle the post-contingency flows that would result when the 500 kV system is loaded to capacity. To address this, the system was designed around a Remedial Action Scheme (RAS), the Northeast Load and Generation Rejection Scheme (the "Northeast LGR") that enables full use of the system pre-contingency, while protecting it post-contingency by arming generation, loads, or the cross-tripping of circuits (which may also reject generation or loads by configuration) for the loss of the 500 kV path. This is a legacy system that does not meet today's planning criteria. For example, ORTAC planning criteria do not permit the use of load rejection following the loss of a single transmission element. However, bringing it up to current standards would involve substantial capital investment that is difficult to justify without the introduction of new needs (e.g., additional demand growth or resource development that would outstrip the system's current capability).

Nonetheless, the IESO recognizes customer reliability concerns and the need to work toward bringing this system up to current standards over time through its bulk and regional planning processes. The recent Northeast Bulk Plan recommendation to add a new single-circuit 500 kV line (operated at 230 kV) between Porcupine TS and Wawa TS, is a first step toward reducing reliance on load rejection in the North & East of Sudbury area. This new line is expected to reduce the frequency and amount of load rejection arming needed to respect the loss of P502X as it provides another supply point into Porcupine TS. This will, however, not address reliability concerns following the loss of D501P, which supplies the most northeastern portions of the system.

6.2.4.2 Difficulty supplying loads during planned outages to circuit D501P

IESO's outage planning staff have also identified that during recent outages to D501P, it has not been possible to supply all customer load in the area due to limitations on the 115 kV system, and certain industrial customers have been forced to reduce their production. These concerns have also been raised by these customers themselves. During D501P outages, generation must also be significantly curtailed, which can remove substantial capacity from the Ontario system.

6.2.4.3 Load Restoration Needs

No load restoration needs were identified in this IRRP.

7. Plan Options and Recommendations

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

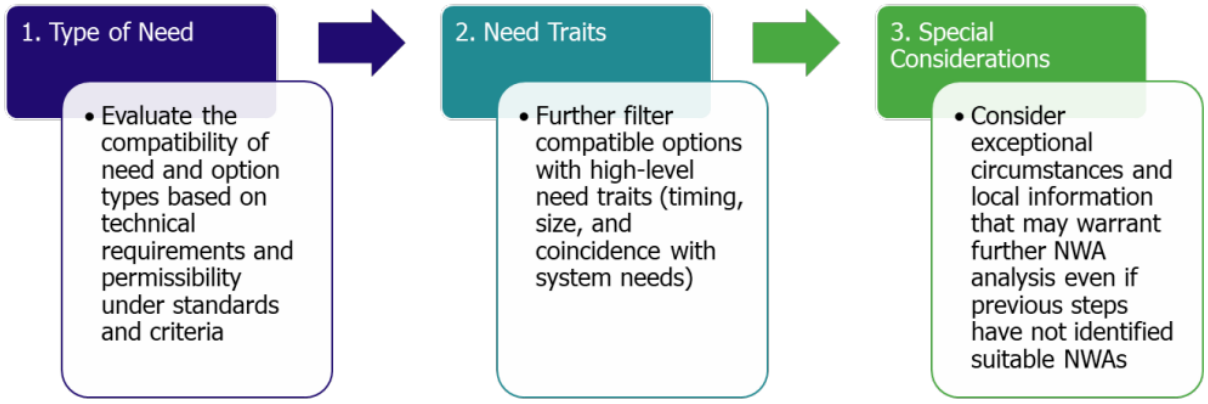
Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

1. Build new infrastructure to increase the load meeting capability of the area. These are commonly referred to as "wires" options and can include recommendations such as 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 recommendations such as local 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. Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed NWA analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 10.

The screening process resulted in NWA being considered for the station capacity need at Ramore TS. NWAs were found to not be suitable for end-of-life and voltage control needs. A like-for-standard sustainment plan is appropriate for the end-of-life needs given that the system studies did not identify any regional needs related to these assets. Needs characterization was completed for the Ramore TS station capacity need.

Figure 10 | IRRP Options Screening Mechanism



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

7.1.1 Ramore TS Station Capacity Need

Options to address station capacity needs can be broadly sorted into two categories:

1. Keep peak loading below existing capacity, using measures such as conservation or distributed energy resources ("Non-wires alternatives), or;
2. Upgrade the station to enable additional capacity (conventional, or "Wires" solution)

Often the two categories can be considered together, with measures to offset peak demand relied upon until no longer feasible or cost effective, at which point an infrastructure upgrade becomes preferred. This type of approach can be preferable if peak capacity is expected to only marginally exceed ratings for the first few years (common in areas with relatively slower load growth), if there is insufficient lead time to accommodate a station upgrade before the need is triggered, or if uncertainty exists in the demand forecast, meaning a capacity upgrade could be "stranded" if the need never materializes. In the case of Ramore TS, there is significant uncertainty in the actual need date due to the high proportion of industrial load at the station, plus under the existing forecast assumptions, load will be only marginally above existing capacity within the study horizon. For both of these reasons, Ramore TS is considered to be a good candidate to consider non-wires measures to keep loading below existing capacity, and consider a station upgrade if and when required. Two non-wires options in particular may be beneficial for this need.

7.1.1.1 Conservation/Energy Efficiency

Conservation (or energy efficiency) involves the use of incentive programs to reduce electricity demand by upgrading/replacing existing equipment with more energy efficient alternatives. In Ontario, the IESO is currently delivering a suite of province-wide programs under the 2021-2024 Conservation and Demand Management Framework. The framework is designed to produce energy savings and offset system peak demand (which occurs in the summer). A component of this framework is the Local Initiatives Programs, which enables the IESO to pursue additional conservation in specific areas to address local electricity system needs while also contributing to meeting provincial system needs.

Given the size and timing of the need, the inherent difficulties of predicting blocky industrial load, and the misalignment with current (summer) system peak, it is recommended to defer a review and decision on targeting conservation as a solution to the Ramore TS need until the next IRRP cycle.

7.1.1.2 Distributed Energy Resources

In order to assess the appropriate DER option, a load duration forecast was created for Ramore TS. This duration forecast consists of a series of year-long hourly profiles ("8760 profile", based on the number of hours in a year), which have been scaled to the appropriate annual peak demand. These profiles are studied to determine the feasibility of using DERs to address the region's needs and determine which type of DERs may be best suited to meet the needs.

Based on the profiles generated for Ramore TS, it was determined that a battery storage solution would be the best fit for the need. The battery storage solution would have a capacity of 1.2 MW and would be able to provide energy for up to six hours. The estimated cost of this battery storage solution is $3 to $3.7 million.

Given that the anticipated need for Ramore TS capacity upgrade is still several years out, it is not recommended that a non-wires alternative be developed at this time. Instead these options should be considered as potential deferral strategies and would be best pursued when actual demand and/or connection requests suggest a capacity need within the next 2-3 years. If these options prove to be insufficient to meet demand, or costlier than a wires alternative, then development work should be initiated to upgrade the station.

7.1.1.3 Station Upgrade

Ramore TS is current made up of a single 10/17 transformer, with a winter LTR of 15 MW. Hydro One has indicated that the station could be upgraded by adding a second, equally sized transformer. This type of upgrade would be expected to cost around $10-$15 million, and can be implemented with about three years' lead time.

Table 5 below shows a comparison of these alternatives, their potential capacity impact, and estimated cost. Note that due to the lead time expected before this work would be triggered, all cost and timing estimates should be considered preliminary, as they will need to be updated closer to when the work is undertaken.

Table 5 | Comparison of Ramore TS options

Option	Capacity Impact	Estimated Cost	Lead Time
Distributed Energy Resources	Increase by 1.2 MW	$3 to $3.7 million	Three years
Station Upgrade	Increase by 15 MW	$10-15 million	Three years

NWA can be viable alternatives should demand grow as projected in Section 6.2.1.1. Otherwise, new solutions may have to be drawn up should a large industrial customer wish to connect to the station. Based on the options above, the Working Group recommends that the station loading at Ramore TS be monitored in between cycles in preparation for the next regional planning cycle.

7.1.2 A4H/A5H End-of-Life Needs

No other regional needs were identified that could be addressed by right-sizing the end-of-life replacement of the A4H/A5H circuits, based on the IRRP demand forecast. Therefore, the Working Group recommends that Hydro One proceed with a like-for-standard replacement for these end-of-life needs. Nonetheless, future system developments (e.g., additional demand growth or resource development in the area) could drive a need for reinforcement in this area in the future. Therefore, the Working Group recommends continued monitoring of developments in the area between regional planning cycles, and that Hydro One touch base with the Working Group before the like-for-standard replacement project is committed, to determine if this recommendation should be revisited.

7.1.3 D2H/D3H End-of-Life Needs

No other regional needs were identified in the IRRP that could be addressed by right-sizing the end-of-life replacement of the D2H/D3H circuits. The Working Group recommends that Hydro One proceed with a like-for-standard replacement for these end-of-life needs.

7.1.4 D3K Thermal Overload

This need was identified in the Needs Assessment stage of regional planning. Since that time, a new RAS has come into service in the Kirkland Lake area to maintain system reliability following various contingencies in the Kirkland Lake area. This RAS will be able to address the identified post-contingency overloading of D3K by arming load rejection for the appropriate A8K or A9K contingency. Therefore, at this time, the Working Group does not recommend any further actions to address this need.

However, the RAS may need to be expanded and/or the system may need to be reinforced should additional demand beyond what was included in the IRRP forecast connect to the system in the Kirkland Lake area. The Working Group recommends that this area be monitored in between regional planning cycles.

7.1.5 Ansonville, Hunta, Kapuskasing Area Voltage Control

The IRRP reviewed the post contingency voltages at Ansonville TS and Hunta SS following the loss of Ansonville T2 and Canyon GS units. The IRRP found that post contingency voltage levels meet ORTAC criteria (Hunta SS is permitted to operate up to 138 kV). Hydro One is currently studying a possible expansion to the Kirkland Lake RAS. This will allow operators to take control actions following the loss of Ansonville T2, among other contingencies. This will give more flexibility to operators should post contingency voltage issues be seen in the future. The Working Group recommends that Hydro One continue to study the possible expansion of the Kirkland Lake RAS. New reactive devices (a 10 MVAr reactor and a 10 MVAr capacitor), controlled by a new remedial action scheme will soon come into service in the Kapuskasing area. These improvements were designed to ensure voltage criteria is met following certain contingencies at Kapuskasing TS, Spruce Falls TS, and Pinard TS. No additional recommendations are required in this IRRP to address voltage control issues in the Kapuskasing area.

Additional reactive devices will be recommended in the Northern Voltage Study to support the broader bulk system across northern Ontario (see Section 4.2.2). The recommendations of this study will provide further reactive support to help alleviate voltage control issues in the North & East of Sudbury area.

7.2 Options and Recommendations for Meeting Longer-Term Needs

7.2.1 Dymond Area Voltage Control Needs

The Working Group recommends that Hydro One investigate right-sizing the capacitors at Dymond TS so that they may be used more effectively to manage voltage in the area. This can be accomplished by reducing the size of the existing capacitors to improve their flexibility. The Working Group recommends that the exact sizing be explored in the RIP in coordination with gathering information on feasible resizing options. The Working Group also recommends Hydro One investigate the feasibility of introducing remote monitoring of the status of the Dymond TS capacitor switching scheme to improve operational visibility.

7.2.2 Kirkland Lake Area Voltage Control Needs

Based on system studies performed in the IRRP, it was found that under the conditions noted in section 6.2.2.2, a 20 MVAr reactive device located at Kirkland Lake TS or a 10 MVAr reactive device at the remote end of circuit K2 would address this need. The Working Group recommends that Hydro One, in the upcoming RIP, further develop options for adding reactive support in the Kirkland Lake area.

7.3 Load Security

7.3.1 Considerations on existing reliance on Remedial Action Schemes in the Northeast and Load Security Needs

Several investments were made over the years to strengthen the area (e.g. Kapuskasing Area Reinforcement). Despite these investments, the reliability issues following the loss of D501P still remains. While proven reliable to protect the rest of the system, the continued long-term reliance on the Northeast LGR may hamper growing interest to connect additional loads (e.g. new mines, mining expansions) and generators in the area.

As the circuit D501P is part of the Bulk Power System, the Working Group recommends that the next bulk system plan in Northeast Ontario address the load security concerns following an outage on D501P. This bulk plan should be triggered if substantial load increases/new resources are expected in the Kapuskasing and northern Cochrane areas.

7.4 Summary of Recommended Actions and Next Steps

Table 6 below shows a summary of all recommended actions as outlined in Section 7.

Table 6 | Summary of Recommended Actions and Next Steps

No.	Need Description	Recommendation	Need Date
1	Station Capacity at Ramore TS	Load growth at Ramore TS will be monitored and revisited in the next cycle of regional planning	2033
2	Voltage control issues with existing capacitors at Dymond TS	Hydro One to investigate options to improve operability of existing capacitors in the upcoming RIP	2030
3	Voltage control issues in the Kirkland Lake area	Hydro One to investigate options of adding reactive devices in the Kirkland Lake area in the upcoming RIP	2030
4	Voltage control issues at Ansonville, Hunta, Kapuskasing Area	Various recommendations, including a new RAS and additional voltage support	Near to Mid-term
5	Thermal overload of circuit D3K upon loss of A8K or A9K when its companion is out of service	The new Kirkland Lake RAS installed in 2022 addresses this issue. Additional load in the area beyond the current forecast will require further study	2030
6	A4H/A5H End-of-Life Need	Hydro One to proceed with plans to replace the affected circuit sections with a like-for-like replacement	2027
7	D2H/D3H End-of-Life Need	Hydro One to proceed with plans to replace the affected circuit sections with a like-for-like replacement	2026
8	ORTAC load security criteria not met for 500 kV circuit outages	Partially addressed by the recent Northeast Bulk Plan. An update to this plan is recommended should significant new resources and/or load connect to the North & East of Sudbury region.	Existing Need

No.	Need Description	Recommendation	Need Date
9	Difficulty supplying loads during planned outages to circuit D501P	Study this need as part of the next bulk system plan for Northeast Ontario in combination with other drivers of system expansion as they develop	Existing Need

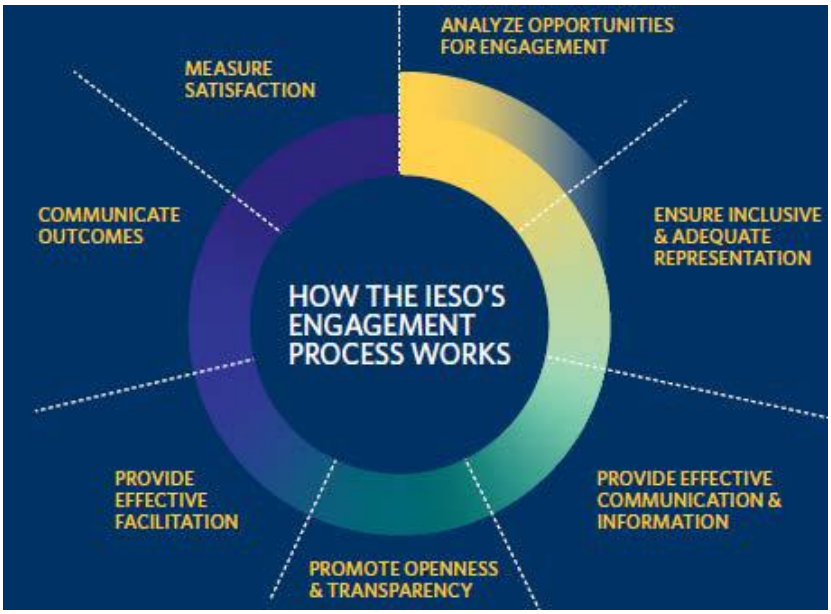
8. Engagement

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

8.1 Engagement Principles

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

Figure 11 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for North & East of Sudbury

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

- Creating the engagement plan for this IRRP involved:
- Discussions to help inform the engagement approach for the planning cycle;
- Developing and implementing engagement tactics to allow for the widest communication of the IESO's planning messages, using multiple channels to reach audiences; and
- Identifying specific stakeholders and communities that should be targeted for one-on-one consultation, based on identified and specific needs.

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

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

8.3 Engage Early and Often

Preliminary discussions were held to help inform the engagement approach and lay the foundation for dialogue in this region where the IESO has not actively engaged with communities and stakeholders. This started with an invitation to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and opportunity to provide input on the North & East of Sudbury Region Scoping Assessment Outcome Report. A public webinar was held in June 2021 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed approach to address them moving forward. Interested parties were invited to submit written feedback on a draft report that was posted for review over a three-week comment period. The final Scoping Assessment was posted later in August 2021, identifying the need for a coordinated regional planning approach and an IRRP.

Following the publication of the final Scoping Assessment, targeted outreach began with municipalities in the region to inform early discussions in the development of the IRRP, including the IESO's approach to engagement. The launch of a broader engagement initiative followed to ensure all interested parties were made aware of this opportunity for input. Three public webinars were held at major stages during IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. These webinars were attended by a

cross-representation of community representatives, businesses, and other stakeholders, and written feedback was collected over a 21-day comment period after each webinar.

The three stages of engagement at which input was invited:

1. The draft engagement plan, electricity demand forecast, and early identified needs – to set the foundation of this planning work.
2. The defined electricity needs for the region and high-level screening of potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

Comments received were primarily focused on:

- Pockets of development in certain areas (I.e. City of Temiskaming Shores, Town of Iroquois Falls and Town of Moosonee)
- Interest in exploring DERs and other non wires alternatives to address regional needs and defer the need for new transmission or large scale generation
- Reliability is a key issue and priority
- Engagement with local First Nations communities, customers and stakeholders is important to understand planned growth and opportunities to participate in developing solutions to meet emerging needs.

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to North & East of Sudbury subscribers, municipalities, and Indigenous and Métis communities. All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's North & East of Sudbury engagement webpage.

Ongoing discussions will be encouraged through the IESO's Northeast Regional Electricity Network to keep interested parties engaged in a two-way dialogue on local developments, priorities, and initiatives to prepare for the next planning cycle. Join the Northeast Network on the IESO website.

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their planning and to ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP.

This targeted outreach was undertaken in tandem with the Northeast Bulk Plan work and engagement given the interrelations of some of the needs at the provincial and regional level, as well as to streamline discussions with local communities. Discussions were held with the Federation of Northern Ontario Municipalities (FONOM) Board of Directors, City of Timmins, Town of Iroquois Falls and Town of Cochrane. These discussions helped to build an understanding about 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 communications were sent to Indigenous communities within the North & East of Sudbury electricity planning region or that may have interests in the region throughout the development of the plan. This includes the First Nation communities of Constance Lake First Nation, Flying Post First Nation, Matachewan First Nation, Mattagami First Nation, Missanabie Cree, Moose Cree First Nation, MoCreebec Council of the Cree Nation, Nipissing First Nation, Taykwa Tagamou First Nation, Temagami First Nation, Wahgoshig First Nation, Wahnapitae First Nation, Northern Lights Métis Council, Timmins Métis Council, Temiskaming Métis Council and Chapleau Métis Council. This electricity planning initiative was also discussed during broader outreach meetings with Indigenous communities in the region.

9. Conclusion

The North & East of Sudbury IRRP identifies electricity needs in the region and opportunities to improve system reliability and operability for the next 20 years. This report recommends a plan to address near- to medium-term issues, and lays out actions to monitor, defer, and/or address long-term needs. The IESO will continue to participate in the Working Group during the next phase of regional planning, the Regional Infrastructure Plan, to provide input and ensure a coordinated approach with bulk system planning where such linkages are identified in the IRRP.

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

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

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REGIONAL INFRASTRUCTURE PLAN REPORT

[North and East of Sudbury]

Regional Infrastructure Plan Report

North and East of Sudbury

[Date: November 03, 2023]

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

North & East of Sudbury Technical working group

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Disclaimer

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

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

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Executive Summary

REGION	**North and East of Sudbury** Region (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")
START DATE: May 10,2023	**END DATE:** November 03, 2023

1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process for the North & East of Sudbury Region, preceded by, the publication of Needs Assessment (NA) report in May 2021 by Hydro One, followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) in August 2021 and in April 2023 published by the IESO respectively.

Hydro One as the lead transmitter undertake the development of a RIP with input from the TWG for the region and publishes a RIP report. The RIP report includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs. This is second cycle of RIP.

2. OBJECTIVES AND SCOPE

Objectives:

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

Scope:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs [2023-2033] identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2023-2043 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the North & East of Sudbury IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

This section provides a detailed overview of the various steps followed during different phases of Regional Planning Process and their outcomes starting with the Needs Assessment, Scoping Assessment, Local Plan, Integrated Regional Resource Plan and finally details the Regional Infrastructure Plan Methodology.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

This section provides a general overview of the Geographical boundaries, Circuit connections and Stations located in the North & East of Sudbury Region though a regional planning area map and a Single Line diagram.

The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. This area is further reinforced through the 500kV circuits P502X and D501P connecting Hanmer TS to Pinard TS.

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

This section provides a summary and brief description of all the projects completed or are currently underway in past ten years.

I. Following Major projects were completed during the last ten years:

- Kapuskasing Area Reinforcement – H9K Circuit Upgrade (2020)
- Kirkland Lake TS (T12/T13) transformers (2017)
- Dymond TS (T3/T4) transformers (2016)
- Timmins TS (T63/T64) with single 83MVA (2016)
- Hanmer TS Northern Station Replacement Project (2022)

II. Following Major projects are underway:

- Kapuskasing Area Reinforcement – Install 115kV Reactive Devices (2023)
- Kirkland Lake TS – Replace low voltage breakers, Instrument Transformers, P&C equipment (2025)
- Hearst TS - Replace low voltage breakers, P&C Equipment, switches (2028)
- Hunta SS - Replace P&C Equipment (2025)
- Porcupine TS – Replace 1 - 500kV/230kV autotransformer (T7), 2- 500kV/115kV autotransformers (T3/T4), switches, station service and P&C equipment (2025)

- Otto Holden TS - Replace 2 – 230 kV/115 kV autotransformers (T3/T4), high voltage breakers, switches, station service equipment, and protections (2027)
- K4 circuit - Refurbish Kirkland Lake TS X Matachewan JCT (10km) (2024)
- A8K/A9K circuits – Refurbish A8K/A9K (90km) (2023)

Note: The planned in-service year for the above projects is tentative and is subject to change.

6. LOAD FORECAST AND STUDY ASSUMPTIONS

During the study period, the load in the North & East of Sudbury Region is expected to grow at an average annual rate of approximately 0.50% in winter and 0.25% in summer from 2023 to 2043.

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2023-2043.
- LDCs reconfirmed load forecasts up to 2040. The additional 3 years of forecasts were extrapolated based on the growth rate as a reasonable position to complete the 20-year period.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is winter peaking, so this assessment is based on winter peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).
- Regional transmission line and auto transformer capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Resources assumptions align with the IRRP.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the North & East of Sudbury Region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway are completed.

I. Needs identified in the region

a. Asset Renewal for Major HV Transmission Equipment

- Kirkland Lake TS
- Hunta SS
- Porcupine TS
- Otto Holden TS
- Hearst TS
- Timmins TS
- Kapuskasing TS
- Dymond TS
- Ansonville TS
- Crystal Falls TS
- Trout Lake TS
- A8K/A9K circuits
- K4 circuit
- T61S circuit
- K1/K2 circuits
- D2H/D3H circuits
- A4H/A5H circuits

b. Station Capacity

- Ramore TS

c. Transmission Line Capacity

- D3K

d. System Reliability, Operation and Load restoration

- Dymond TS - Voltage violation
- Kirkland Lake TS - Voltage control
- Ansonville, Hunta, Kapuskasing TS - Voltage control
- ORTAC load security criteria not met for 500 kV circuit outages
- Difficulty supplying loads during planned outages to circuit D501P

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the North & East of Sudbury Region. The needs include those previously identified in the NA and IRRP for the North & East of Sudbury Region as well as any new needs identified during the RIP phase.

9. CONCLUSION AND RECOMMENDATIONS

The major infrastructure investments recommended by the TWG in the North & East of Sudbury Region is given below:

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Kirkland Lake TS	Replacement of Instrument Transformers, P&C equipment, station service equipment and low voltage circuit breakers.	Hydro One Transmission	2025	36
Hunta SS	Replacement of P&C and telecom equipment.	Hydro One Transmission	2025	12
Porcupine TS	Replacement of 1-500/230kV 360MVA autotransformer (T8), 2- 500/115kV 225MVA autotransformers (T3/T4), switches, station service equipment and P&C equipment.	Hydro One Transmission	2026	91
Otto Holden TS	Replacement of 2-230/115 kV 60MVA autotransformers (T3/T4), high voltage circuit breakers, switches, station service equipment, and P&C equipment.	Hydro One Transmission	2027	74
Hearst TS	Replacement of low voltage circuit breakers, switches, P&C Equipment.	Hydro One Transmission	2028	19
Timmins TS	Replacement of 1-115/27.6kV 83MVA (T2) transformer and associated protections.	Hydro One Transmission	2028	14

Kapuskasing TS	Replace low voltage circuit breakers, switches, station service equipment and protections.	Hydro One Transmission	2030	24
Dymond TS	Replacement of low voltage breakers, and associated P&C equipment.	Hydro One Transmission	2031	42
Ansonville TS	Replace P&C equipment, Instrument transformers, station service equipment.	Hydro One Transmission	2031	11
Crystal Falls TS	Replacement of 2-230/44kV 42MVA (T5/T6) transformers, station service equipment, switches and P&C equipment.	Hydro One Transmission	2031	32
Trout Lake TS	Replacement of 2–230/44 kV 125MVA (T3/T4) transformers, low voltage circuit breakers and surge arresters.	Hydro One Transmission	2033	17
K4	Replace conductor and refurbish circuit Kirkland Lake TS X Matachewan JCT (10km)	Hydro One Transmission	2024	4
T61S	Replace conductor and refurbish circuit Timmins TS x Shiningtree JCT (115km)	Hydro One Transmission	2024	
K1/K2	Replace conductor and refurbish circuit Kirkland Lake TS x American Barrick JCT (14km)	Hydro One Transmission	2024	4
D2H/D3H*	Replace conductor and refurbish circuit Hunta SS x Abitibi Canyon SS (183km)	Hydro One Transmission	2029	96
A4H/A5H**	Replace conductor and refurbish circuit Tunis JCT x Fournier JCT (47km)	Hydro One Transmission	2027	22
Station Capacity Needs				
Ramore TS	To be monitored and reviewed in next planning cycle	Hydro One Distribution	NA	NA
Transmission Line Capacity Needs				
D3K	Monitoring & further exploration in future RIP cycle	Hydro One Transmission	NA	NA

System Reliability, Operation and Load restoration Needs				
Dymond TS	Continue to investigate sizing of the existing 115kV SC11 & SC12 capacitor banks	Hydro One Transmission	NA	NA

Note:

a) The planned in-service dates are tentative and subject to change
b) Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required)

* IESO to inform by end of Q2 2025 if an upgrade is required

** IESO to inform by end of 2024 if an upgrade is required

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1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process where, Hydro One as the lead transmitter undertakes the development of a RIP with input from the TWG for the region and publishes a RIP report. The second cycle of the Regional Planning process for the North & East of Sudbury Region was initiated with the publication of Needs Assessment (NA) report in May 2021 by Hydro One, followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) in August 2021 and in April 2023 published by the IESO respectively.

The RIP report includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

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

Table 1: North & East of Sudbury Region TWG Participants

Hydro One Networks Inc. (Lead Transmitter)	Lead Transmitter
Independent Electricity System Operator ("IESO")	System Operator
Hydro One Networks Inc. (Distribution)	LDC
North Bay Hydro	LDC
Northern Ontario Wires Inc.	LDC
Hearst Power Distribution Co.	LDC
Greater Sudbury Hydro Inc.	LDC

2. OBJECTIVES AND SCOPE OF REGIONAL INFRASTRUCTURE PLAN

This RIP report examines the needs in the North & East of Sudbury Region. Its objectives are to:

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2023-2033) identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2023-2033 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the North & East of Sudbury IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

3.1 Overview

Bulk System Planning, Regional Planning and Distribution Planning are the three levels of planning for the electricity system in Ontario. Bulk system planning typically looks at issues that impact the system on a provincial level and requires longer lead time and larger investments. Comparatively, planning at the regional and distribution levels look at issues on a more regional or localized level. Typically, the most

essential and effective regional planning horizon is the near- to medium-term (1- 10 years), whereas long-term (10-20 years) regional planning mostly provides a future outlook with little details about investments because the needs and other factors may vary over time. On the other hand, bulk system plans are developed for the long term because of the larger magnitude of the investments.

The regional planning process begins with a Needs Assessment (NA) which is led by the transmitter to identify, assess, and document which of the needs

a) can be addressed directly between the customer and transmitter along with a recommended plan, and;
b) that require further regional coordination and identification of Local Distribution Companies (LDCs) to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the Technical Working Group (TWG) as to whether further regional coordination is necessary to address some or all the regional needs. If no, further regional coordination is required, recommendation to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The Region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs

a) are local in nature,
b) require limited investments in wires (transmission or distribution) solutions, and;
c) do not require upstream transmission investments.

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

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

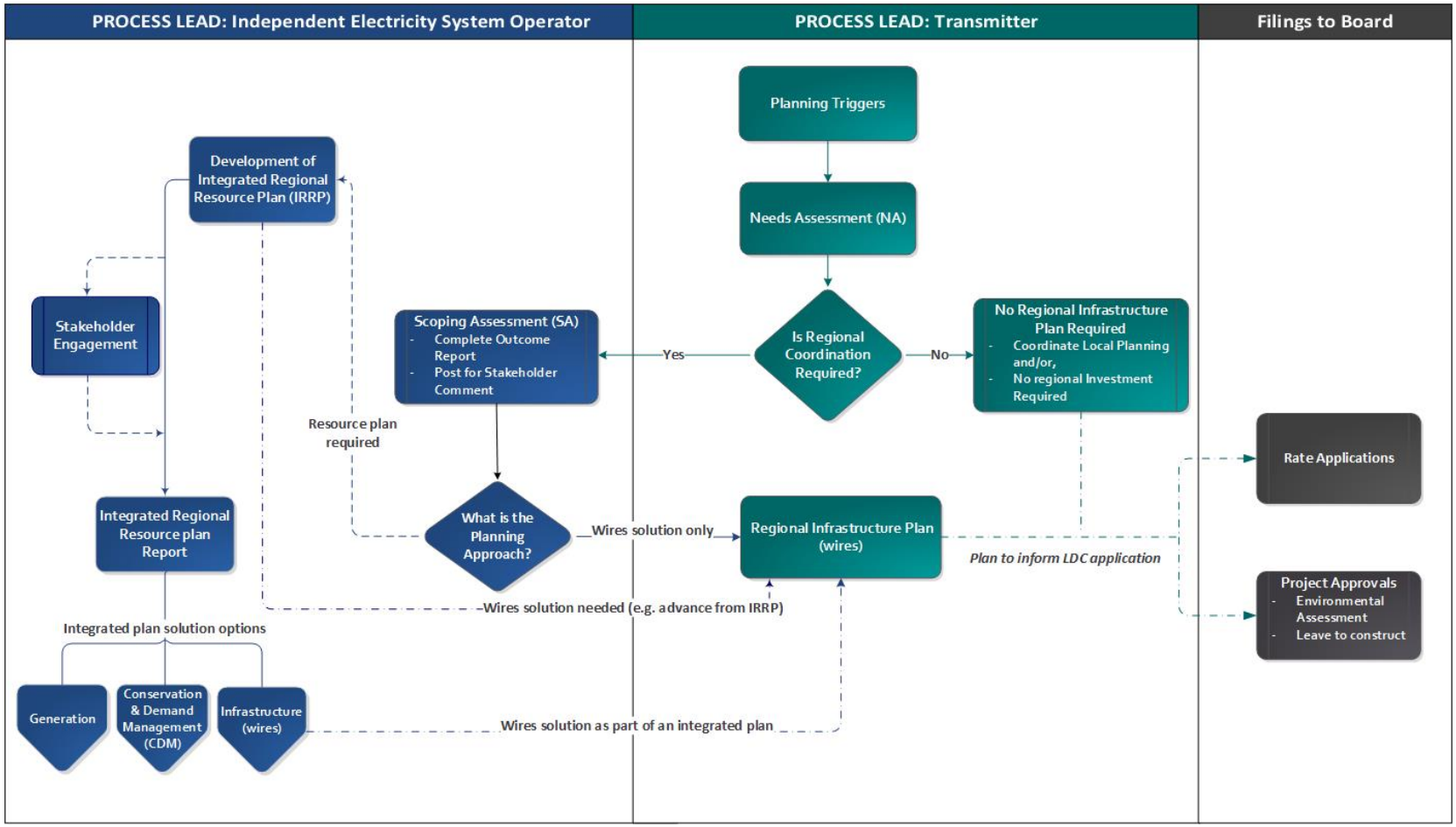
If and when an IRRP identifies that resource and/or wires options may be most appropriate to meet a need, resource/wires planning can be initiated in parallel with the IRRP or in the RIP phase to undertake a more detailed assessment, develop specific resource/wires alternatives, and recommend a preferred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

The RIP phase is the final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and, development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the

region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the Ontario Energy Board (OEB) timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

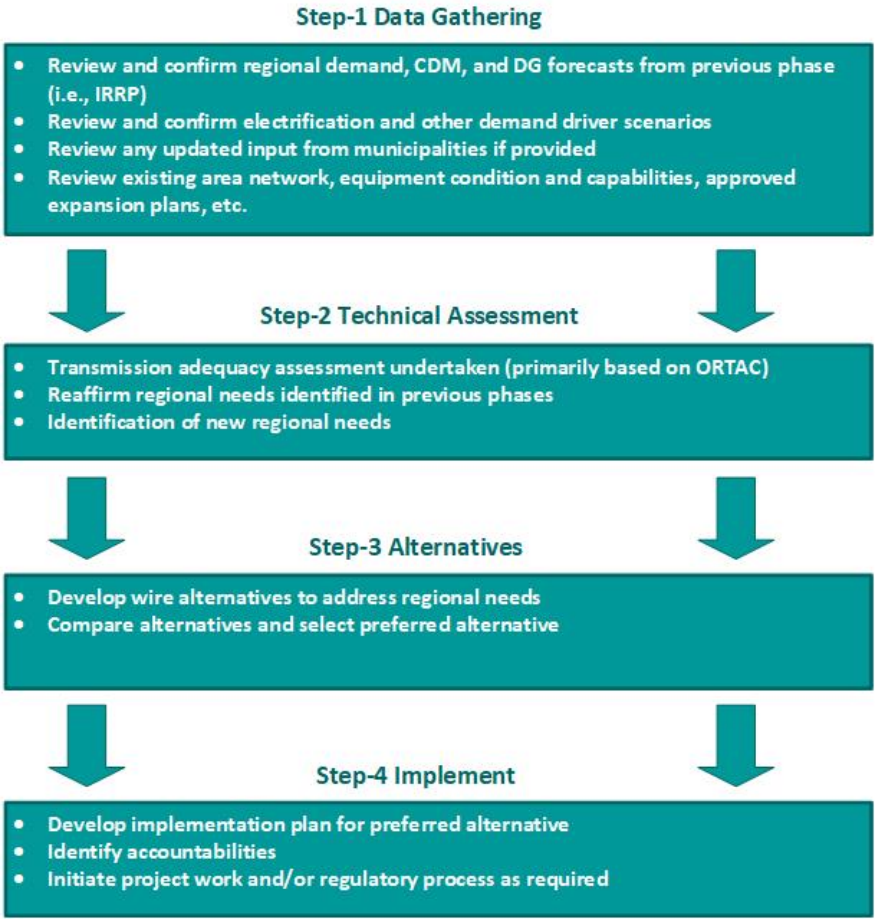
The various phases of Regional Planning Process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome are shown below in Figure-1.

Figure-1 Regional Planning Process Flowchart



3.2 Regional Infrastructure Plan Methodology

Figure-2 Regional Infrastructure Plan Methodology



Regional Infrastructure Plan phase is a four-step process which are described below:

3.2.1. Data Gathering:

The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the technical working group (TWG) to reconfirm or update the information as required. The data collected includes:

- Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As agreed by TWG members, the load forecast from the IRRP was used for this RIP.

- Review and confirm electrification and other growth scenarios which effects the projects recommended in in previous stages and also update the inputs provided by the Municipalities.
- Existing area network and capabilities including any bulk system power flow assumptions.
- Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

3.2.2. Technical Assessment:

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

3.2.3. Alternative Development:

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

3.2.4. Implementation Plan:

The fourth and last step is the development of the implementation plan for the preferred alternative, identifying accountabilities and initiate project work or obtain permissions from Regulatory Commission if any.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. The geographical boundaries of the North & East of Sudbury region is shown in Figure 3 below.

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. This area is further reinforced through the 500kV circuits P502X and D501P connecting Hanmer TS to Pinard TS.

This region has the following four local distribution companies (LDC):

- Hydro One Networks (distribution)
- Northern Ontario Wires Inc
- Hearst Power Ltd
- North Bay Hydro Distribution Ltd.
- Greater Sudbury Hydro Inc.

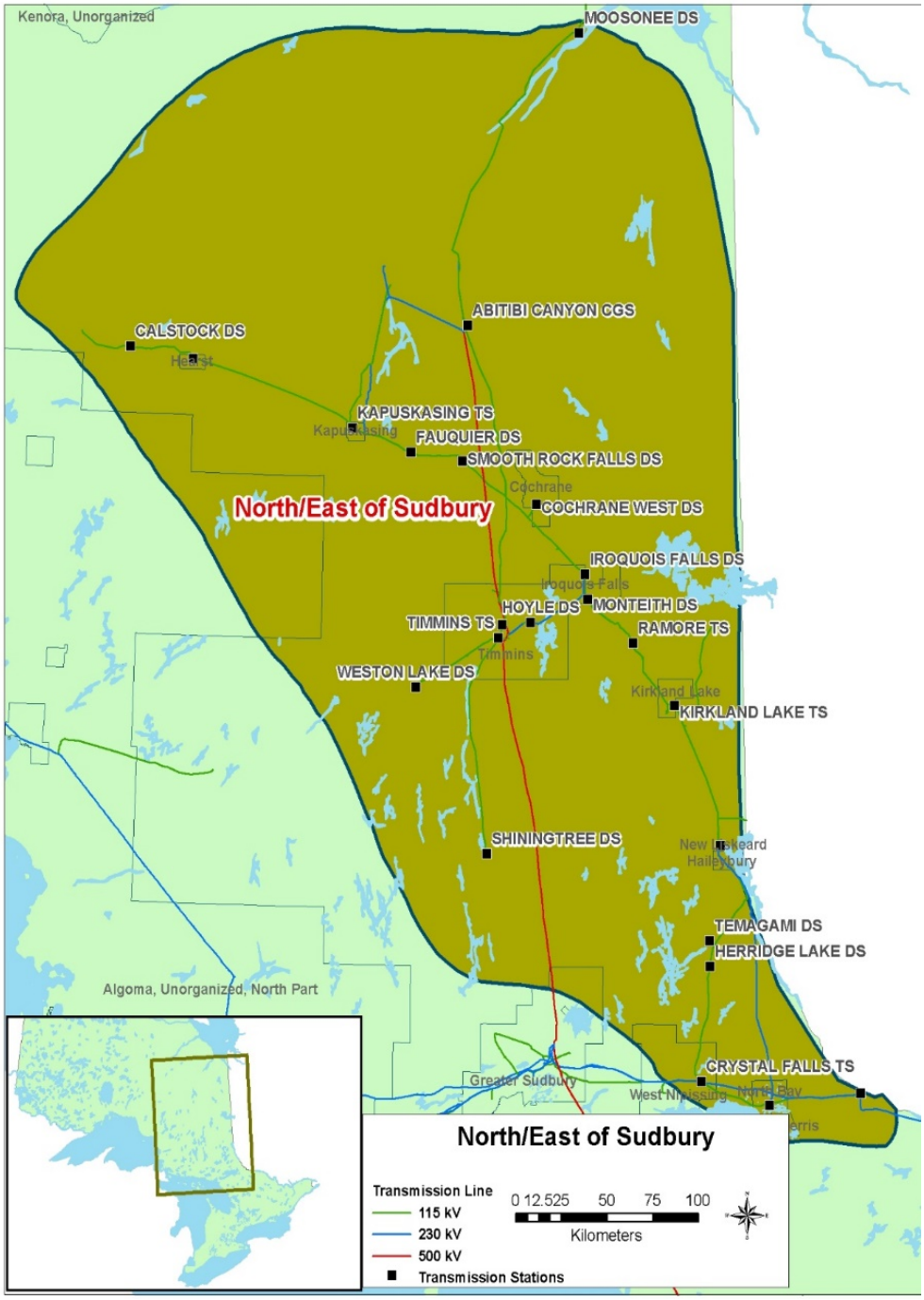


Figure 3: Map of North & East of Sudbury Regional Planning Area

The circuits and stations of the area are summarized in the Table 2 below:

Table 2: Transmission Station and Circuits in the North & East of Sudbury Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
A4H/A5H	D23G	Ansonville TS*	Otter Rapids GS
A8K/A9K	H22D	Crystal Falls TS	Abitibi Canyon GS
D2H/D3H	H23S/H24S	Dymond TS*	Empire CGS (10 MW)
H6T/H7T	K38S	Hearst TS	Martin's Meadows CGS (10 MW)
P13T/P15T	L20D	Hunta SS	Abitibi CGS (10 MW)
T7M/T8M	L21S	Kapuskasing TS	Long Lake CGS (10 MW)
D2L	P91G	Kirkland Lake TS	Kipling GS (164 MW)
H9K	R21D	Little Long SS	Kipling 2 GS (79 MW)
K2	W71D	Moosonee SS	Harmon GS (140 MW)
K4		North Bay TS	Harmon 2 GS (78 MW)
L1S		Otter Rapids SS	Smoky Falls 2 GS (264 MW)
L5H		Otto Holden TS*	Little Long GS (MW)
D3K		Pinard TS*	Little Long 2 GS (70 MW)
P7G		Porcupine TS*	A.P. Kapuskasing CGS (57 MW)
T61S		Ramore TS	Nagagami CGS (18 MW)
F1E		Spruce Falls TS	A.P. Calstock CGS (39 MW)
T2R		Timmins TS	Carmichael Falls CGS (18 MW)
		Trout Lake TS	Smooth Rock Fall CGS (8 MW)
		Widdifield SS	Yellow Falls CGS (16 MW)
			Iroq Falls Power CGS (126 MW)
			New Liskeard CGS (30 MW)
			Northland Power Kirkland Lake CGS (172 MW)

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of North & East of Sudbury region is shown in Figure 4 below.

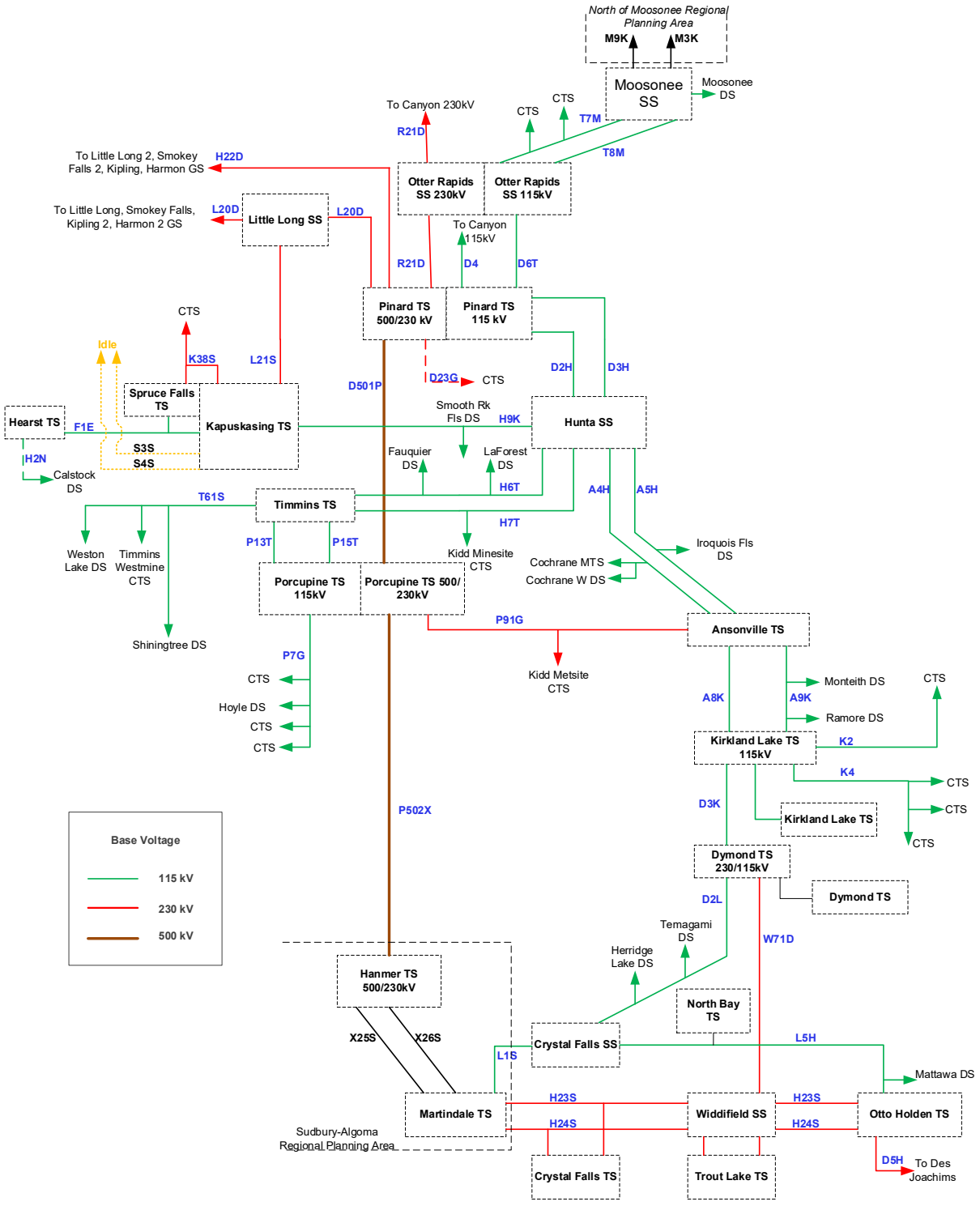


Figure 4: North & East of Sudbury Transmission Single Line Diagram

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

In this section a complete list of all the projects that are completed in past ten years or are currently underway is provided and are briefly discussed in the sub sections. As a part of this or previous Regional Planning Cycle(s), several "Major HV Transmission Projects" were recommended in the **North & East of Sudbury** Region to improve the supply capability and reliability.

Hydro One, being the only Transmission Asset Owner (TAO) in the region have undertaken execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. Following Major projects were completed during the last ten years:

- Kapuskasing Area Reinforcement – H9K Circuit Upgrade (ISD 2020)
- Kirkland Lake TS (T12/T13) transformer replacement (ISD 2017)
- Dymond TS (T3/T4) transformer replacement (ISD 2016)
- Timmins TS (T63/T64) replace with a single 83MVA (ISD 2016)

II. Following Major projects are underway:

- Kapuskasing Area Reinforcement – Install 115kV Reactive Devices (ISD 2023)
- Kirkland Lake TS – Replace low voltage breakers, Instrument Transformers, P&C equipment (ISD 2025)
- Hearst TS - Replace low voltage breakers, P&C Equipment, switches (ISD 2028)
- Hunta SS - Replace P&C Equipment (ISD 2025)
- Porcupine TS – Replace 1 - 500kV/230kV autotransformer (T7), 2- 500kV/115kV autotransformers (T3/T4), switches, station service and P&C equipment (ISD 2025)
- Otto Holden TS - Replace 2 – 230 kV/115 kV autotransformers (T3/T4), high voltage breakers, switches, station service equipment, and protections (ISD 2027)
- K4 circuit - Refurbish Kirkland Lake TS X Matachewan JCT (10km) (ISD 2024)
- A8K/A9K circuits – Refurbish A8K/A9K (90km) (ISD 2023)

Note: The planned in-service year for the above projects is tentative and is subject to change.

6. LOAD FORECAST AND STUDY ASSUMPTIONS

6.1. Load Forecast

The TWG participants reviewed and verified that there is no material change in load forecast from those used in the North & East of Sudbury Region IRRP Load Forecasts (April 2023). Thus, the IRRP forecasts were used in development of this Report. TWG participants, including representatives from LDC's, IESO and Hydro One, provided information and input for the IRRP Load forecast, which also includes the inputs from the Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). New industrial/mining load connections requests have been received after publication of IRRP report. These new potential load connections have not been explicitly listed in the load forecast tables, however these loads have been studied in the RIP to assess their impact to the area.

During the study period, the load in the North & East of Sudbury Region is expected to grow at an average annual rate of approximately 0.50% in winter and 0.25% in summer from 2023 to 2043. The Region is winter peaking, so this assessment is based on winter peak loads. This growth does not include significant increases in the industrial sector.

Figures 5 & 6 shows the North & East of Sudbury Region extreme summer/winter weather net coincident and non-coincident load forecast from 2023 to 2043. The load forecasts from the North & East of Sudbury Region were adopted as agreed to by the TWG. The load forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the step-down transformer stations.

Non-coincident and coincident forecast for the individual stations in the region is available in Appendix A and is used to determine any need for station capacity relief in the region.

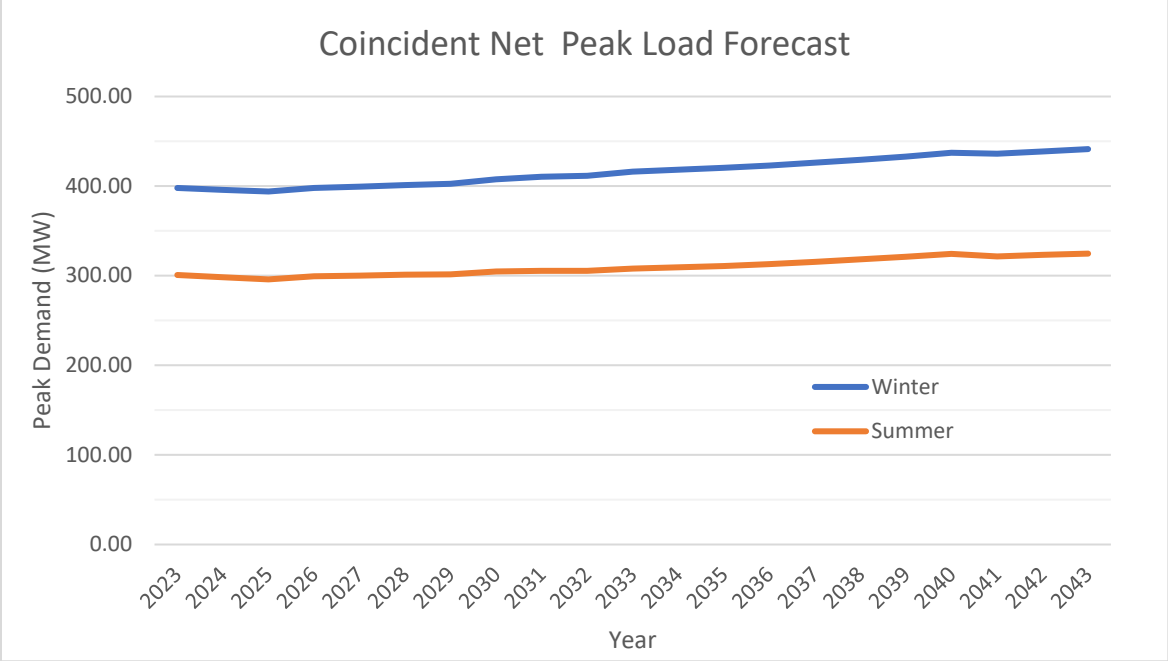


Figure 5: North & East of Sudbury Region summer/winter coincident Net Peak Load Forecast

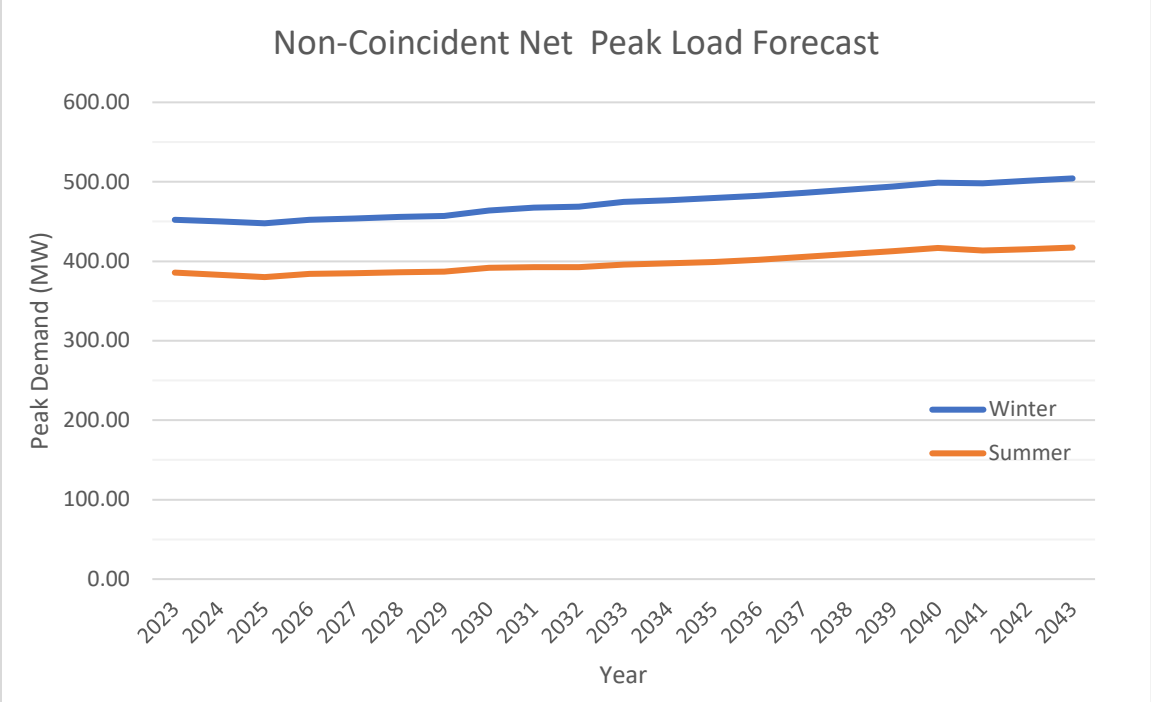


Figure 6: North & East of Sudbury Region summer/winter Non-coincident Net Peak Load Forecast

6.2. Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2023-2043.
- LDCs reconfirmed load forecasts up to 2040. The additional 3 years of forecasts were extrapolated based on the growth rate as a reasonable position to complete the 20-year period.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is winter peaking, so this assessment is based on winter peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the winter 10-day Limited Time Rating (LTR).
- Regional transmission line and auto transformer capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Resources assumptions align with the ORTAC.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the North & East of Sudbury Region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway, listed in **"Section 5"** are completed.

In current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- North & East of Sudbury Region Second cycle Needs Assessment Report, Completed in May 2021 by Hydro One
- North & East of Sudbury Region Second cycle Scoping Assessment Report, Completed in August 2021 by the IESO
- North & East of Sudbury Region Second cycle Integrated Regional Resource Plan Report, Completed in April 2023 by the IESO

The Technical Working Group identified several regional needs based on the forecasted load demand over the near to mid-term period in the reports mentioned above. The results of the Adequacy Assessment to define the needs are discussed in sub-sections "7.1 to 7.4" and a detailed description and status of plans to meet these needs are given in **"Section 8"** of this report.

7.1. Asset Renewal Needs for Major HV Transmission Equipment

In addition to the asset renewal needs identified in previous regional planning cycle, Hydro One and TWG has also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the **North & East of Sudbury** Region. The complete list of major HV transmission equipment requiring replacement in the **North & East of Sudbury** Region is provided in table 3 in this sub-section. Hydro One is the only Transmission Asset Owner (TAO) in the Region

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

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

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

Table 3: Major HV Transmission Asset assessed for Replacement in the region

Station/Circuit	Need Description	Planned ISD
Kirkland Lake TS	Replacement of Instrument Transformers, P&C equipment, station service equipment and low voltage circuit breakers.	2025
Hunta SS	Replacement of P&C and telecom equipment.	2027

Porcupine TS	Replacement of 1-500/230kV 360MVA autotransformer (T8), 2- 500/115kV 225MVA autotransformers (T3/T4), switches, station service equipment and P&C equipment.	2026
Otto Holden TS	Replacement of 2-230/115 kV 60MVA autotransformers (T3/T4), high voltage circuit breakers, switches, station service equipment, and P&C equipment.	2027
Hearst TS	Replacement of low voltage circuit breakers, switches, P&C Equipment.	2030
Timmins TS	Replacement of 1-115/27.6kV 83MVA (T2) transformer and associated protections.	2028
Kapuskasing TS	Replace low voltage circuit breakers, switches, station service equipment and protections.	2030
Dymond TS	Replacement of low voltage breakers, and associated P&C equipment.	2031
Ansonville TS	Replace P&C equipment, Instrument transformers, station service equipment.	2032
Crystal Falls TS	Replacement of 2-230/44kV 42MVA (T5/T6) transformers, station service equipment, switches and P&C equipment.	2031
Trout Lake TS	Replacement of 2–230/44 kV 125MVA (T3/T4) transformers, low voltage circuit breakers and surge arresters.	2033
K4	Replace conductor and refurbish circuit Kirkland Lake TS X Matachewan JCT (10km)	2024
T61S	Replace conductor and refurbish circuit Timmins TS x Shiningtree JCT (115km)	2024
K2	Replace conductor and refurbish circuit Kirkland Lake TS x American Barrick JCT (14km)	2024
D2H/D3H*	Replace conductor and refurbish circuit Hunta SS x Abitibi Canyon SS (183km)	2029
A4H/A5H**	Replace conductor and refurbish circuit Tunis JCT x Fournier JCT (47km)	2027

Note: The planned in-service year for the above projects is tentative and is subject to change.

* IESO to inform by end of Q2 2025 if an upgrade is required

** IESO to inform by end of 2024 if an upgrade is required

7.2. Station Capacity Needs

Over the study period [2023-2043] RIP reviewed the capacity of all the 230kV and 115kV Transforming stations within the North & East of Sudbury Region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 4 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 4: North & East of Sudbury Region Station Capacity Needs in the study period

Station Name	Capacity (MW)	2023 Loading (MW)	Station 10 day LTR (MW)	Need Date
Ramore TS	15	12	15	2033

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.3. Transmission Line Capacity Needs

Over the study period [2023-2033] RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the North & East of Sudbury Region. The NA and IRRP studies had previously indicated that the following Transmission lines require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast and following contingencies, the Transmission lines which require capacity relief during the study period are shown in Table 5 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 5: North & East of Sudbury Region Transmission Line Capacity Needs in the study period

Sr.no.	Name of Circuit	Name of Section	Contingency	Need Date
1	D3K	Dymond x Kirkland Lake	N-1-1 (AxK O/S + loss of companion circuit)	2030

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.4. System Reliability, Operation and Load Restoration Needs

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

Further, loads are to be restored in the restoration times[1] specified as follows:

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

The post contingency voltage control issues have also been listed in Table 6 below.

Table 6: North & East of Sudbury Region System Operational Needs and Voltage Control in the study period

Sr.no.	Reliability / Operational Need	Description	Need Date
1	Dymond TS	Voltage control violations when switching existing 115kV Dymond TS capacitor banks	2030
2	Kirkland Lake TS	Voltage control challenges in Kirkland Lake area during concurrent outages to Kirkland Lake TS SVC and Northland Power Kirkland Lake GS.	2030
3	Ansonville, Hunta, Kapuskasing	Post contingency voltage control challenges for the loss of Ansonville T2 and Canyon Units.	Existing

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

4	ORTAC load security criteria not met for 500 kV circuit outages	Loss of load and resources during outages to any of the two major 500kV transmission lines in the Northeast	Existing
5	Difficulty supplying loads during planned outages to circuit D501P	Area loads cannot be adequately supplied during planned circuit outages	Existing

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the North & East of Sudbury Region. These needs include those previously identified in the NA and IRRP for the North & East of Sudbury Region as well as any new needs identified during the RIP phase. All estimated costs included in the alternative analysis are considered as planning budgetary estimates and are used for comparative purposes only and may vary. The Needs in the region are summarized below in Table 6 below:

8.1 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for "right sizing" the equipment:

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

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

8.1.1. Asset Name – Location

Table 7: Needs identified in the region

Station/Circuit	Need Description	Planned ISD
Kirkland Lake TS	Replacement of Instrument Transformers, P&C equipment, station service equipment and low voltage circuit breakers. This investment will replace equipment that is in poor condition and deemed end of life.	2025
Hunta SS	Replacement of P&C and telecom equipment. This investment will replace equipment that is in poor condition and deemed end of life.	2025
Porcupine TS	Replacement of 1-500/230kV 360MVA autotransformer (T8), 2- 500/115kV 225MVA autotransformers (T3/T4), switches, station service equipment and P&C equipment. This investment will replace end of life transformers to reduce the risk of interruptions caused by transformer asset failure.	2026
Otto Holden TS	Replacement of 2-230/115 kV 60MVA autotransformers (T3/T4), high voltage circuit breakers, switches, station service equipment, and P&C equipment. This investment will replace equipment that is in poor condition and deemed end of life. It will also replace end of life transformers to reduce the risk of interruptions caused by transformer asset failure. The new transformers will be installed in a greenfield location and connected to the existing 230kV bus at Holden CGS via a 230 conductor/bus. The replacement transformers and associated equipment will be constructed within the limits of a new station called Antonie TS	2027
Hearst TS	Replacement of low voltage circuit breakers, switches, P&C Equipment. This investment will replace equipment that is in poor condition and deemed end of life.	2028

Timmins TS	Replacement of 1-115/27.6kV 83MVA (T2) transformer and associated protections. This investment will replace equipment that is in poor condition and deemed end of life. It will also help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure.	2028
Kapuskasing TS	Replace low voltage circuit breakers, switches, station service equipment and protections. This investment will replace equipment that is in poor condition and deemed end of life.	2030
Dymond TS	Replacement of low voltage breakers, and associated P&C equipment. This investment will replace equipment that is in poor condition and deemed end of life.	2031
Ansonville TS	Replace P&C equipment, Instrument transformers, station service equipment. This investment will replace equipment that is in poor condition and deemed end of life.	2031
Crystal Falls TS	Replacement of 2-230/44kV 42MVA (T5/T6) transformers, station service equipment, switches and P&C equipment. This investment will replace equipment that is in poor condition and deemed end of life. It will also help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure.	2031
Trout Lake TS	Replacement of 2–230/44 kV 125MVA (T3/T4) transformers, low voltage circuit breakers and surge arresters. This investment will replace equipment that is in poor condition and deemed end of life. It will also help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure.	2033
A8K/A9K	Replace conductor and refurbish circuit Ansonvillle x Kirkland Lake (180km) This investment will replace the conductor and also increase the thermal capacity to meet system needs.	2023

K4	Replace conductor and refurbish circuit Kirkland Lake TS X Matachewan JCT (10km) This investment will replace the conductor with a like for standard conductor. Right sizing has been taken into consideration to meet supply capacity of loads on the line.	2024
T61S	Replace conductor and refurbish circuit Timmins TS x Shining tree JCT (115km) This investment will replace the conductor with a like for standard conductor. Right sizing has been taken into consideration to meet supply capacity of loads on the line.	2024
K2	Replace conductor and refurbish circuit Kirkland Lake TS x American Barrick JCT (14km) This investment will replace the conductor with a like for standard conductor. Right sizing has been taken into consideration to meet supply capacity of loads on the line.	2024
D2H/D3H	Replace conductor and refurbish circuit Hunta SS x Abitibi Canyon SS (183km) This investment will replace the conductor with a like for standard conductor.	2029
A4H/A5H	Replace conductor and refurbish circuit Tunis JCT x Fournier JCT (47km) This investment will replace the conductor with a like for standard conductor.	2027

8.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period [2023-2043] for the 230kV and 115kV Transforming stations in the North & East of Sudbury Region using either the summer or winter peak load forecasts that were provided by the study team. Based on the results, the following Station capacity needs have been identified in the during the study period:

8.2.1 Ramore TS

Ramore TS is a single transformer 115/27.6kV 17MVA station. The summer and winter 10-Day LTR is 15MW, and load at this station is expected to exceed the LTR in 2033.

Table 8: Ramore TS Load Forecast

Station	LTR (MW)	Load Forecast										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ramore TS	15	13.7	13.8	13.9	14	14.2	14.3	14.4	14.8	14.9	15	15.1

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

Alternative 1 - Maintain Status Quo: Ramore TS will continue to operate with the existing installed capacity, and Hydro One will monitor load growth to ensure supply needs are met.

Alternative 2 – Replace T1 with a new 115/27.6 42MVA unit: Replacing T1 with the next largest standard size unit will increase the station LTR to 38MW. The station LTR will remain limited to the size of the transformer as there will still only be a single unit installed at the station. This was considered and rejected as this would result in additional cost of approximately $10M and prematurely retire T1 transformer. This transformer remains in acceptable condition and is not scheduled to be replaced by Hydro One within the study period due to end-of-life needs.

The TWG recommends Alternative 1 as the preferred and cost effective alternative for addressing the need. The capacity need will arise in 2033 and will allow both Hydro One and area LDCs to monitor load growth and take corrective action when needed. This need will also be refreshed in the next cycle or regional planning.

8.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period [2023-2043] for the 230kV and 115kV Transmission line circuits in the North & East of Sudbury Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified in the during the study period:

No new line capacity needs have been identified in this planning cycle.

8.3.1 D3K (Thermal Violation)

D3K is a single circuit 115kV transmission line which provides a critical network path between Dymond TS and Kirkland Lake TS. This circuit is approximately 80km in length and serves to provide connection to generating stations and provide a path for network flows. Sections of this line will start to experience supply capacity violations at the end of the study period and will require mitigating solutions to allow for increased flows. The circuit section is described below;

1. Dymond TS x Kirkland Lake TS (80km) – For the loss of A8K and A9K, the companion circuit will exceed its Long-Term Emergency (LTE) rating. As studied in the IRRP and verified in the RIP this is expected to occur as early as 2030 based on demand forecast.

Solutions to address these needs will be further explored in future planning cycles given the long-term nature of this need. Flows on this line and its violations are heavily influenced by area resource assumptions, and demand forecast for customers in the Kirkland Lake area. In addition, a new Kirkland Lake RAS (Remedial Action Scheme) has been installed to initiate control actions such as load rejection for system contingencies. Currently, this RAS will trip loads and avoid the D3K thermal violation. This scheme will continue to be utilized by control room operators and it is expected that reliance on this scheme will gradually be reduced as system upgrades and replacements are complete in the future. The TWG will continue to monitor this need in future planning cycles and initiate an investment should this violation be advanced due to changing system conditions.

8.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period [2023-2043] to cater this need**.**

8.4.1 Dymond TS – Voltage Control

IESO operations team has reported voltage violations at Dymond TS during capacitor bank switching. Dymond TS has two 115kV shunt capacitor banks (SC11/SC12) each rated at 24MVar. IESO has observed that switching the banks under certain system conditions voltages can exceed the maximum voltage and step change permitted by IESO Market Rules. These violations are largely dependent on system configuration (W71D O/S + Loss of D3K) and less sensitive to area loading patterns. Voltage violations are not observed during system conditions where all elements are In-service, or one element is O/S as there is sufficient reactive support from adjacent stations to support Dymond pre-contingency.

Alternative 1 - Maintain Status Quo: IESO and Hydro One operations will continue to control the system with other reactive devices in the northeast. The existing capacitor banks can continue to be utilized to help meet single contingency planning scenarios.

Alternative 2 – De-rate the Existing capacitor banks (SC11/SC12) Hydro One can de-rate the capacitor bank between 14-16MVar to ensure voltage limits upon cap bank switching remain within acceptable limits. This option helps with operations primarily for a W71D+D3K contingency. This option reduces the total var support at Dymond by 50% and due to the de-rating in size. It has been discussed with the TWG that operations may have to rely on other reactive devices in the northeast to provide steady state voltage support for other system configurations.

The TWG recommends to continue to investigating the need to a de-rate the existing capacitor banks and provide enhanced automation and visibilty.

8.4.2 Kirkland TS – Voltage Control

IESO has reported difficulties in maintaining adequate system voltages in the Kirkland Lake area during outage conditions. Concurrent outages to the Kirkland Lake SVC and Northland Power Kirkland Lake Generating facility result in declining voltages at the end of the radial K2 transmission line.

Kirkland Lake TS presently has a 115kV connection SVC, and shunt capacitor bank to help maintain voltages during steady state, and contingencies.

K2 circuit is a radial line with multiple industrial customers tapped of this circuit. Voltage performance on this circuit is directly attributed to the load pattern of these customers. It is expected that future loads connecting to this circuit will be required to maintain their voltage within reasonable limits as a condition to connect. A new Kirkland Lake RAS is also available to address thermal and voltage violations in the area as a control action and can be expanded to include additional inputs and outputs. Planning level cost for a new 115kV capacitor bank will cost between $10M-$15M, and will be largely influenced by the available space at the station and the control building.

The TWG recommends to monitor the voltage performance at Kirkland Lake TS bus and ensure that voltages on the K2 delivery points remain within reasonable limits. Hydro One and IESO will engage in further discussion on system operating limits, and resource options to mitigate this finding.

8.4.3 Ansonville, Hunta, Kapuskasing Voltage Control

Voltage violations at Ansonville TS, Hunta TS, and Kapuskasing TS can occur for the loss of Ansonville T2 and Abitibi Canyon generating units. This is coupled with the general challenge of maintaining system voltages within acceptable limits in the northeast as a whole. A new Kirkland Lake RAS (remedial action scheme) has been installed to help operators take control actions for system contingencies. This RAS can also be expanded to accommodate changing system needs which will help to provide operating flexibility

in the future. Kapuskasing RAS will also be installed to provide voltage support in the Kapuskasing area for system contingencies. This RAS can also be expanded when needed to meet future system needs.

Porcupine SVC will also be refurbished in the planning cycle and will provide much needed reactive support for the northeast.

The TWG will continue to address voltage control issues as needed to accommodate system needs. IESO and Hydro One continues to work towards finding robust solutions that provide voltage support without over reliance on load rejection and other adverse control actions. No additional investments are required from this regional infrastructure plan to address this need.

8.4.4 ORTAC load security criteria not met for 500 kV circuit outages

The North & East of Sudbury region is supplied by two 500 kV circuits, P502X from Hanmer TS to Porcupine TS and D501P from Porcupine TS to Pinard TS.

The system connects substantial amount of hydroelectric generation on the Moose River and loads in the region. The planning requirement to respect the loss of either of the 500kV circuits results in the need to rely on a Remedial Action Scheme (RAS), the Northeast Load and Generation Rejection Scheme (the "Northeast LGR"), that enables full use of the scheme following the loss of a single transmission element.

This is a legacy system that does not meet today's planning criteria for the use of load rejection following the loss of a single transmission element. However, bringing it up to current standards would involve substantial capital investment that is difficult to justify without the introduction of new needs. Future bulk projects such as the new 230kV line between Porcupine TS and Wawa TS will help to reduce reliance on area RASs following a P502X outage, however, does not address the loss of D501P and will still result in load rejection for area customers. The Working Group (TWG) recommends that the next bulk system plan in Northeast Ontario address the load security concerns following an outage on D501P and develop a plan to proactively reduced reliance on RAS.

8.4.5 Difficulty supplying loads during planned outages to circuit D501P

IESO's outage planning staff have also identified that during recent outages to D501P, it has not been possible to supply all customer load in the area due to limitations on the 115 kV system, and certain industrial customers have been forced to reduce their production. These concerns have also been raised by these customers themselves. During D501P outages, generation must also be significantly curtailed, which can remove substantial capacity from the Ontario system.

Hydro One recently implemented a protection scheme to allow D501P outages and working to address the shortfalls experienced during the implementation. TWG recommends to continue discussions with Hydro One and IESO operation to ensure future projects can be completed effectively during 500kV

outages and the project team will work to develop effective solutions for the specific projects in question. These solutions may include modifications/additions to area RASs schemes or new transmission facilities.

8.5 Long Term Considerations

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

9. CONCLUSION AND RECOMMENDATION

This section concludes the Regional Infrastructure Plan Report for North & East of Sudbury Region. The Major Infrastructure investments recommended by the TWG in the near and mid-term planning horizon [2023-2033] are provided in Table 7 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 9: Recommended Plans over the next 10 Years

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Kirkland Lake TS	Replacement of Instrument Transformers, P&C equipment, station service equipment and low voltage circuit breakers.	Hydro One Transmission	2025	36
Hunta SS	Replacement of P&C and telecom equipment.	Hydro One Transmission	2025	12
Porcupine TS	Replacement of 1-500/230kV 360MVA autotransformer (T8), 2- 500/115kV 225MVA autotransformers (T3/T4), switches, station service equipment and P&C equipment.	Hydro One Transmission	2026	91
Otto Holden TS	Replacement of 2-230/115 kV 60MVA autotransformers (T3/T4), high voltage circuit breakers, switches, station service equipment, and P&C equipment.	Hydro One Transmission	2027	74
Hearst TS	Replacement of low voltage circuit breakers, switches, P&C Equipment.	Hydro One Transmission	2028	19
Timmins TS	Replacement of 1-115/27.6kV 83MVA (T2) transformer and associated protections.	Hydro One Transmission	2028	14
Kapuskasing TS	Replace low voltage circuit breakers, switches, station service equipment and protections.	Hydro One Transmission	2030	24
Dymond TS	Replacement of low voltage breakers, and associated P&C equipment.	Hydro One Transmission	2031	42

Ansonville TS	Replace P&C equipment, Instrument transformers, station service equipment.	Hydro One Transmission	2031	11
Crystal Falls TS	Replacement of 2-230/44kV 42MVA (T5/T6) transformers, station service equipment, switches and P&C equipment.	Hydro One Transmission	2031	32
Trout Lake TS	Replacement of 2–230/44 kV 125MVA (T3/T4) transformers, low voltage circuit breakers and surge arresters.	Hydro One Transmission	2033	17
K4	Replace conductor and refurbish circuit Kirkland Lake TS X Matachewan JCT (10km)	Hydro One Transmission	2024	4
T61S	Replace conductor and refurbish circuit Timmins TS x Shiningtree JCT (115km)	Hydro One Transmission	2024	
K1/K2	Replace conductor and refurbish circuit Kirkland Lake TS x American Barrick JCT (14km)	Hydro One Transmission	2024	4
D2H/D3H*	Replace conductor and refurbish circuit Hunta SS x Abitibi Canyon SS (183km)	Hydro One Transmission	2029	96
A4H/A5H**	Replace conductor and refurbish circuit Tunis JCT x Fournier JCT (47km)	Hydro One Transmission	2027	22
Station Capacity Needs				
Ramore TS	To be monitored and reviewed in next planning cycle	Hydro One Distribution	NA	NA
Transmission Line Capacity Needs				
D3K	Monitoring & further exploration in future RIP cycle	Hydro One Transmission	NA	NA
System Reliability, Operation and Load restoration Needs				
Dymond TS	Continue investigating to correctly size the existing 115kV SC11 & SC12 capacitor banks	Hydro One Transmission	NA	NA

Note:

a) The planned in-service dates are tentative and subject to change

b) Cost are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required)

* IESO to inform by end of Q2 2025 if an upgrade is required

** IESO to inform by end of 2024 if an upgrade is required

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. December 18, 2018)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. October 1, 2022)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Winter Weather Adjusted Net Load Forecast

Table A.1: North & East of Sudbury Region – Winter Coincident- Net Load Forecast

Transformer Station	DESN ID	LTR (MVA)	LTR (MW)	Net Extreme Winter Weather Station Peak Demand Forecast, Coincident to NE of Sudbury Region (MW)																		
				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Crystal Falls TS	T5/T6	53.60	48.24	19.94	20.19	20.23	20.28	20.31	20.37	20.38	23.70	25.18	25.31	25.47	25.65	25.84	26.16	26.42	26.70	26.97	27.24	28.59	29.11	29.62
Hearst TS	T4	39.60	35.64	18.39	18.37	18.36	18.37	18.37	18.39	18.38	18.38	18.36	18.34	18.34	18.36	18.39	18.44	18.51	18.60	18.68	18.76	18.59	18.61	18.62
Kapuskasing TS	T5/T6	106.50	95.85	5.88	5.84	5.81	5.79	5.76	5.74	5.70	5.68	5.64	5.61	5.59	5.57	5.56	5.56	5.58	5.60	5.62	5.64	5.52	5.50	5.48
Kirkland Lake TS	T12/T13	57.60	51.84	40.32	40.24	40.21	40.21	40.18	40.19	40.19	40.22	40.17	40.11	40.11	40.12	40.14	40.16	40.26	40.38	40.50	40.62	40.34	40.35	40.36
North Bay TS	T1/T2	64.10	57.69	25.16	24.02	22.88	23.27	23.71	24.14	24.57	25.01	25.43	25.83	26.25	26.69	27.16	27.65	28.14	28.63	29.13	29.63	29.41	29.78	30.14
Ramone TS	T1	20.90	18.81	12.36	12.44	12.51	12.58	12.71	12.83	12.94	13.27	13.38	13.47	13.58	13.70	13.84	13.98	14.12	14.26	14.41	14.56	14.66	14.79	14.93
Timmins TS	T2/T4	113.10	101.79	52.77	52.81	52.92	53.09	53.22	53.42	53.58	53.78	53.87	53.93	54.09	54.28	54.48	54.69	55.03	55.41	55.78	56.16	55.85	56.04	56.22
Dymond TS	T3/T4	62.00	55.80	30.82	30.79	30.80	30.84	30.87	30.94	30.96	31.01	31.01	30.98	33.88	33.93	34.00	34.08	34.23	34.40	34.57	34.73	35.13	35.42	35.71
Trout Lake	T3/T4	209.50	188.55	98.85	97.86	96.96	100.18	100.79	101.50	102.00	102.58	103.32	103.85	104.79	105.56	106.38	107.38	108.51	109.69	110.87	113.07	112.08	112.92	113.76
Calstock DS	-	-	-	5.29	5.28	5.29	5.30	5.31	5.33	5.35	5.37	5.38	5.38	5.40	5.41	5.43	5.44	5.47	5.50	5.53	5.57	5.54	5.56	5.57
CochraneMTS	-	-	-	11.46	11.39	11.34	11.28	11.22	11.16	11.10	11.05	10.99	10.92	10.88	10.84	10.81	10.79	10.79	10.79	10.79	10.79	10.62	10.58	10.53
Cochran West DS	-	-	-	3.55	3.55	3.56	3.57	3.58	3.59	3.59	3.60	3.61	3.61	3.62	3.63	3.65	3.66	3.69	3.71	3.74	3.76	3.74	3.75	3.76
Fauquier DS	-	-	-	2.08	2.09	2.10	2.11	2.12	2.13	2.14	2.15	2.16	2.17	2.18	2.19	2.20	2.22	2.24	2.26	2.28	2.30	2.29	2.30	2.31
Herridge Lake DS	-	-	-	3.41	3.42	3.43	3.45	3.46	3.47	3.49	3.50	3.51	3.52	3.53	3.54	3.56	3.58	3.61	3.64	3.66	3.69	3.67	3.69	3.70
Hoyle DS	-	-	-	7.05	7.06	7.07	7.08	7.09	7.12	7.13	7.15	7.15	7.16	7.17	7.19	7.22	7.25	7.28	7.33	7.37	7.41	7.37	7.39	7.41
Iroquois Falls DS	-	-	-	5.19	5.16	5.15	5.13	5.11	5.09	5.07	5.06	5.03	5.01	5.00	4.99	4.98	4.98	4.98	4.99	5.00	5.01	4.94	4.93	4.91
Laforest Road DS	-	-	-	12.79	12.80	12.83	12.87	12.90	12.95	12.99	13.03	13.06	13.07	13.11	13.16	13.21	13.27	13.35	13.45	13.54	13.64	13.55	13.60	13.65
Mattawa DS	-	-	-	5.06	5.07	5.09	5.11	5.13	5.15	5.17	5.19	5.20	5.21	5.23	5.26	5.28	5.31	5.35	5.39	5.43	5.47	5.45	5.47	5.49
Monteith DS	-	-	-	2.93	2.94	2.96	2.97	2.99	3.00	3.02	3.03	3.04	3.05	3.06	3.08	3.10	3.12	3.15	3.18	3.21	3.23	3.22	3.23	3.25
Moosonee DS	-	-	-	14.31	14.31	14.33	14.37	14.40	14.45	14.48	14.53	14.55	14.56	14.59	14.63	14.68	14.74	14.82	14.91	15.00	15.09	15.01	15.05	15.09
Shiningtree DS	-	-	-	3.95	3.94	3.94	3.93	3.93	3.93	3.94	3.94	3.94	3.93	3.93	3.93	3.93	3.94	3.95	3.96	3.98	3.99	3.96	3.96	3.96
Smooth Rock Falls DS	-	-	-	1.80	1.80	1.80	1.81	1.81	1.81	1.81	1.82	1.82	1.82	1.82	1.82	1.82	1.83	1.84	1.85	1.86	1.87	1.85	1.86	1.86
Temagami DS 2	-	-	-	1.39	1.40	1.40	1.41	1.42	1.43	1.44	1.45	1.46	1.47	1.48	1.49	1.50	1.51	1.53	1.54	1.56	1.58	1.57	1.58	1.59
Verner DS	-	-	-	5.93	5.93	5.94	5.95	5.96	5.97	5.97	5.97	5.97	5.97	5.98	5.99	6.00	6.03	6.06	6.09	6.13	6.16	6.11	6.12	6.13
Warren DS	-	-	-	7.10	7.09	7.09	7.10	7.10	7.11	7.11	7.11	7.10	7.10	7.10	7.11	7.12	7.14	7.17	7.21	7.24	7.28	7.21	7.22	7.23

Table A.2: North & East of Sudbury Region – Winter non-Coincident – Net Load Forecast

Transformer Station	DESN ID	LTR (MVA)	LTR (MW)	Winter Weather Station Non Coincident to NE of Sudbury Region (MW)																			
				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Crystal Falls TS	T5/T6	53.60	48.24	29.98	30.36	30.42	30.49	30.54	30.63	30.65	35.63	37.87	38.06	38.30	38.57	38.86	39.34	39.74	40.15	40.56	40.96	42.99	43.77	44.55
Hearst TS	T4	39.60	35.64	20.41	20.38	20.38	20.39	20.38	20.40	20.39	20.39	20.37	20.35	20.36	20.38	20.41	20.46	20.54	20.64	20.73	20.82	20.63	20.65	20.67
Kapuskasing TS	T5/T6	106.50	95.85	14.72	14.62	14.55	14.49	14.40	14.35	14.27	14.21	14.12	14.03	13.98	13.95	13.92	13.92	13.96	14.01	14.07	14.12	13.80	13.76	13.72
Kirkland Lake TS	T12/T13	57.60	51.84	40.90	40.82	40.79	40.79	40.75	40.77	40.77	40.79	40.75	40.68	40.68	40.69	40.71	40.73	40.83	40.95	41.08	41.20	40.92	40.93	40.94
North Bay TS	T1/T2	64.10	57.69	33.17	31.67	30.16	30.68	31.26	31.83	32.39	32.98	33.53	34.05	34.61	35.20	35.82	36.45	37.10	37.75	38.41	39.06	38.78	39.26	39.74
Ramone TS	T1	20.90	18.81	13.76	13.85	13.93	14.01	14.16	14.29	14.42	14.78	14.90	15.00	15.12	15.26	15.41	15.57	15.73	15.89	16.05	16.21	16.33	16.48	16.62
Timmins TS	T2/T4	113.10	101.79	54.22	54.26	54.38	54.55	54.68	54.89	55.05	55.25	55.35	55.41	55.58	55.77	55.98	56.20	56.55	56.93	57.32	57.70	57.38	57.58	57.77
Dymond TS	T3/T4	62.00	55.80	39.70	39.66	39.66	39.72	39.75	39.84	39.88	39.94	39.93	39.90	43.63	43.70	43.78	43.89	44.08	44.30	44.52	44.73	45.25	45.62	45.99
Trout Lake	T3/T4	209.50	188.55	101.32	100.30	99.38	102.68	103.31	104.03	104.54	105.14	105.90	106.44	107.40	108.19	109.03	110.05	111.22	112.43	113.63	115.89	114.88	115.74	116.59
Calstock DS	-	-	-	8.76	8.75	8.77	8.79	8.80	8.83	8.86	8.91	8.92	8.92	8.95	8.97	9.00	9.01	9.06	9.11	9.17	9.23	9.18	9.21	9.24
CochraneMTS	-	-	-	12.77	12.69	12.63	12.57	12.50	12.44	12.37	12.31	12.25	12.17	12.12	12.08	12.05	12.02	12.02	12.02	12.03	12.03	11.83	11.79	11.74
Cochran West DS	-	-	-	3.71	3.72	3.72	3.73	3.74	3.76	3.76	3.77	3.78	3.78	3.79	3.80	3.82	3.84	3.86	3.89	3.91	3.94	3.91	3.92	3.94
Fauquier DS	-	-	-	2.22	2.23	2.24	2.25	2.26	2.28	2.28	2.29	2.30	2.31	2.32	2.33	2.35	2.37	2.39	2.41	2.43	2.45	2.44	2.45	2.46
Herridge Lake DS	-	-	-	4.00	4.01	4.02	4.03	4.05	4.07	4.08	4.10	4.11	4.12	4.13	4.15	4.17	4.19	4.22	4.26	4.29	4.32	4.30	4.32	4.34
Hoyle DS	-	-	-	8.88	8.88	8.89	8.91	8.93	8.96	8.97	9.00	9.01	9.01	9.03	9.05	9.08	9.12	9.17	9.22	9.28	9.33	9.27	9.30	9.32
Iroquois Falls DS	-	-	-	5.50	5.48	5.46	5.44	5.42	5.40	5.38	5.36	5.34	5.31	5.30	5.29	5.28	5.28	5.28	5.29	5.30	5.31	5.23	5.22	5.21
Laforest Road DS	-	-	-	13.52	13.53	13.56	13.60	13.64	13.69	13.73	13.77	13.80	13.81	13.86	13.91	13.96	14.02	14.11	14.21	14.31	14.41	14.32	14.37	14.42
Mattawa DS	-	-	-	5.16	5.17	5.19	5.21	5.23	5.26	5.27	5.29	5.31	5.32	5.34	5.36	5.39	5.42	5.46	5.50	5.54	5.58	5.55	5.58	5.60
Monteith DS	-	-	-	3.00	3.01	3.02	3.04	3.05	3.07	3.08	3.10	3.11	3.12	3.13	3.15	3.17	3.19	3.22	3.25	3.28	3.31	3.29	3.31	3.33
Moosonee DS	-	-	-	14.63	14.63	14.65	14.69	14.72	14.77	14.81	14.85	14.87	14.88	14.92	14.96	15.01	15.06	15.15	15.24	15.34	15.43	15.34	15.38	15.43
Shiningtree DS	-	-	-	4.62	4.61	4.60	4.60	4.60	4.60	4.60	4.61	4.60	4.59	4.59	4.59	4.60	4.60	4.62	4.63	4.65	4.67	4.63	4.63	4.63
Smooth Rock Falls DS	-	-	-	1.98	1.98	1.98	1.98	1.98	1.99	1.99	1.99	1.99	1.99	2.00	2.00	2.00	2.01	2.02	2.03	2.04	2.05	2.03	2.04	2.04
Temagami DS 2	-	-	-	1.80	1.81	1.82	1.84	1.85	1.86	1.87	1.89	1.90	1.91	1.92	1.93	1.95	1.96	1.98	2.01	2.03	2.05	2.04	2.06	2.07
Verner DS	-	-	-	6.06	6.06	6.06	6.07	6.08	6.10	6.09	6.10	6.10	6.10	6.10	6.12	6.13	6.16	6.19	6.22	6.26	6.29	6.24	6.25	6.26
Warren DS	-	-	-	7.53	7.52	7.52	7.53	7.53	7.55	7.54	7.54	7.53	7.53	7.53	7.54	7.55	7.58	7.61	7.65	7.68	7.72	7.65	7.66	7.67

Table A.3: North & East of Sudbury Region – Summer Coincident – Net Load Forecast

Transformer Station	DESN ID	LTR (MVA)	LTR (MW)	Net Extreme Summer Weather Station Peak Demand Forecast, Coincident to NE of Sudbury Region (MW)																			
				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Crystal Falls TS	T5/T6	48.40	43.56	14.80	15.18	15.34	15.50	15.64	15.81	15.93	18.48	18.70	18.83	18.99	19.17	19.37	19.70	19.97	20.26	20.55	20.83	21.63	22.02	22.41
Hearst TS	T4	32.90	29.61	12.50	12.63	12.59	12.56	12.51	12.48	12.43	12.39	12.34	12.28	12.26	12.24	12.24	12.26	12.30	12.36	12.41	12.46	12.25	12.24	12.22
Kapuskasing TS	T5/T6	94.20	84.78	36.17	36.03	35.95	35.92	35.85	35.83	35.70	35.64	35.53	35.41	35.38	35.39	35.43	35.54	35.75	35.98	36.21	36.42	35.76	35.76	35.76
Kirkland Lake TS	T12/T13	47.30	42.57	26.02	25.92	25.87	25.84	25.78	25.75	25.72	25.72	25.66	25.59	25.56	25.54	25.52	25.51	25.56	25.63	25.69	25.76	25.51	25.49	25.47
North Bay TS	T1/T2	61.70	55.53	14.98	13.88	12.78	13.21	13.65	14.09	14.53	14.97	15.39	15.81	16.23	16.67	17.14	17.61	18.09	18.58	19.07	19.56	19.40	19.77	20.14
Ramone TS	T1	18.30	16.47	4.96	4.99	5.01	5.03	5.08	5.13	5.18	5.32	5.36	5.40	5.44	5.48	5.54	5.60	5.65	5.71	5.77	5.83	5.87	5.92	5.98
Timmins TS	T2/T4	104.20	93.78	33.45	33.39	33.38	33.43	33.43	33.48	33.49	33.54	33.52	33.48	33.52	33.59	33.68	33.79	34.01	34.26	34.50	34.74	34.31	34.37	34.44
Dymond TS	T3/T4	54.00	48.60	25.93	25.83	25.77	25.76	25.72	25.71	25.65	25.63	25.56	25.48	26.77	26.78	26.80	26.86	26.98	27.13	27.27	27.41	27.31	27.41	27.52
Trout Lake	T3/T4	186.60	167.94	66.13	64.94	63.85	66.78	67.14	67.58	67.79	68.10	68.46	68.76	69.30	69.83	70.42	71.18	72.08	73.03	73.97	75.31	74.44	75.00	75.55
Calstock DS	-	-	-	3.76	3.75	3.75	3.75	3.75	3.75	3.76	3.78	3.78	3.77	3.77	3.78	3.78	3.79	3.81	3.83	3.85	3.88	3.84	3.85	3.85
CochraneMTS	-	-	-	9.99	9.90	9.83	9.77	9.68	9.62	9.53	9.46	9.39	9.31	9.25	9.21	9.17	9.15	9.15	9.16	9.17	9.17	8.94	8.89	8.84
Cochran West DS	-	-	-	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.57	2.57	2.57	2.57	2.57	2.58	2.59	2.61	2.63	2.65	2.67	2.63	2.63	2.64
Fauquier DS	-	-	-	1.92	1.93	1.93	1.93	1.94	1.95	1.95	1.95	1.95	1.95	1.96	1.97	1.98	1.99	2.01	2.03	2.05	2.06	2.04	2.05	2.05
Herridge Lake DS	-	-	-	1.65	1.65	1.65	1.65	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.67	1.68	1.68	1.70	1.71	1.73	1.74	1.72	1.72	1.73
Hoyle DS	-	-	-	4.47	4.47	4.46	4.46	4.46	4.47	4.46	4.47	4.46	4.45	4.46	4.46	4.47	4.49	4.52	4.55	4.57	4.60	4.54	4.55	4.56
Iroquois Falls DS	-	-	-	4.96	4.93	4.90	4.87	4.84	4.81	4.78	4.75	4.71	4.68	4.66	4.64	4.63	4.63	4.63	4.64	4.65	4.66	4.55	4.53	4.51
Laforest Road DS	-	-	-	11.04	11.02	11.02	11.03	11.03	11.05	11.04	11.05	11.04	11.02	11.04	11.06	11.09	11.14	11.21	11.29	11.38	11.46	11.30	11.32	11.34
Mattawa DS	-	-	-	4.37	4.36	4.37	4.38	4.38	4.39	4.39	4.40	4.40	4.40	4.41	4.42	4.43	4.46	4.49	4.53	4.57	4.60	4.54	4.55	4.57
Monteith DS	-	-	-	1.91	1.91	1.91	1.92	1.92	1.93	1.93	1.93	1.94	1.94	1.94	1.95	1.96	1.97	1.99	2.01	2.03	2.05	2.02	2.03	2.04
Moosonee DS	-	-	-	4.97	4.96	4.95	4.96	4.96	4.96	4.96	4.97	4.97	4.96	4.97	4.97	4.98	4.99	5.02	5.05	5.09	5.12	5.06	5.06	5.07
Shiningtree DS	-	-	-	2.43	2.42	2.41	2.41	2.40	2.40	2.39	2.39	2.38	2.37	2.37	2.37	2.37	2.36	2.37	2.38	2.39	2.40	2.36	2.36	2.36
Smooth Rock Falls DS	-	-	-	1.64	1.64	1.63	1.63	1.63	1.63	1.63	1.63	1.62	1.62	1.62	1.62	1.62	1.62	1.63	1.64	1.65	1.66	1.63	1.63	1.63
Temagami DS 2	-	-	-	0.98	0.98	0.98	0.99	0.99	1.00	1.00	1.01	1.01	1.01	1.02	1.02	1.03	1.04	1.05	1.06	1.07	1.08	1.07	1.08	1.08
Verner DS	-	-	-	4.04	4.03	4.02	4.02	4.01	4.01	3.99	3.98	3.97	3.96	3.96	3.96	3.97	3.98	4.01	4.03	4.06	4.08	4.01	4.01	4.01
Warren DS	-	-	-	5.02	5.00	4.99	4.98	4.97	4.97	4.94	4.93	4.91	4.89	4.89	4.89	4.89	4.90	4.93	4.96	4.98	5.01	4.92	4.91	4.91

Table A.4: North & East of Sudbury Region – Summer non-Coincident – Net Load Forecast

Transformer Station	DESN ID	LTR (MVA)	LTR (MW)	Net Extreme Summer Weather Station Peak Demand Forecast, Coincident to NE of Sudbury Region (MW)																			
				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Crystal Falls TS	T5/T6	48.40	43.56	23.02	23.61	23.86	24.10	24.33	24.59	24.78	28.74	29.08	29.28	29.53	29.82	30.13	30.63	31.06	31.52	31.96	32.40	33.64	34.24	34.85
Hearst TS	T4	32.90	29.61	14.79	14.95	14.89	14.86	14.80	14.77	14.70	14.66	14.60	14.53	14.50	14.49	14.48	14.50	14.55	14.62	14.68	14.74	14.50	14.48	14.46
Kapuskasing TS	T5/T6	94.20	84.78	64.77	64.52	64.36	64.32	64.18	64.15	63.93	63.82	63.61	63.40	63.35	63.37	63.45	63.64	64.01	64.43	64.84	65.21	64.03	64.03	64.02
Kirkland Lake TS	T12/T13	47.30	42.57	27.37	27.27	27.21	27.18	27.11	27.08	27.05	27.05	26.99	26.91	26.88	26.86	26.85	26.83	26.89	26.96	27.03	27.09	26.83	26.81	26.79
North Bay TS	T1/T2	61.70	55.53	18.22	16.87	15.55	16.06	16.60	17.14	17.67	18.20	18.72	19.22	19.74	20.28	20.84	21.42	22.00	22.60	23.19	23.78	23.59	24.04	24.49
Ramone TS	T1	18.30	16.47	7.20	7.24	7.27	7.31	7.38	7.45	7.51	7.72	7.78	7.83	7.89	7.96	8.04	8.12	8.21	8.29	8.38	8.46	8.52	8.60	8.68
Timmins TS	T2/T4	104.20	93.78	36.64	36.57	36.56	36.61	36.61	36.67	36.68	36.74	36.72	36.67	36.72	36.79	36.89	37.01	37.25	37.52	37.79	38.05	37.58	37.65	37.72
Dymond TS	T3/T4	54.00	48.60	30.08	29.97	29.90	29.89	29.83	29.83	29.76	29.74	29.66	29.56	31.06	31.06	31.09	31.16	31.30	31.47	31.64	31.79	31.68	31.80	31.93
Trout Lake	T3/T4	186.60	167.94	77.61	76.21	74.93	78.37	78.80	79.31	79.55	79.92	80.35	80.69	81.33	81.95	82.65	83.54	84.59	85.71	86.81	88.38	87.36	88.01	88.67
Calstock DS	-	-	-	6.96	6.94	6.93	6.94	6.93	6.94	6.96	6.99	6.99	6.98	6.98	6.99	7.00	7.01	7.05	7.09	7.13	7.18	7.11	7.12	7.13
CochraneMTS	-	-	-	12.44	12.33	12.24	12.16	12.06	11.98	11.87	11.79	11.69	11.59	11.53	11.47	11.42	11.40	11.40	11.41	11.42	11.42	11.14	11.08	11.01
Cochran West DS	-	-	-	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.85	2.85	2.84	2.85	2.85	2.86	2.87	2.89	2.92	2.94	2.96	2.91	2.92	2.92
Fauquier DS	-	-	-	2.57	2.57	2.57	2.58	2.59	2.59	2.60	2.60	2.60	2.61	2.61	2.62	2.64	2.65	2.68	2.70	2.73	2.75	2.72	2.73	2.74
Herridge Lake DS	-	-	-	2.24	2.24	2.24	2.25	2.25	2.26	2.26	2.26	2.26	2.26	2.26	2.27	2.28	2.29	2.31	2.33	2.35	2.36	2.33	2.34	2.35
Hoyle DS	-	-	-	6.36	6.35	6.34	6.35	6.35	6.35	6.35	6.35	6.34	6.33	6.34	6.35	6.36	6.39	6.42	6.47	6.51	6.54	6.46	6.47	6.48
Iroquois Falls DS	-	-	-	5.47	5.43	5.40	5.37	5.34	5.31	5.27	5.23	5.20	5.16	5.14	5.12	5.11	5.10	5.11	5.12	5.13	5.14	5.02	5.00	4.98
Laforest Road DS	-	-	-	13.27	13.25	13.24	13.26	13.26	13.28	13.27	13.28	13.27	13.25	13.26	13.29	13.33	13.38	13.47	13.57	13.67	13.77	13.58	13.60	13.63
Mattawa DS	-	-	-	5.18	5.18	5.18	5.19	5.20	5.21	5.21	5.22	5.22	5.22	5.23	5.24	5.26	5.29	5.33	5.37	5.42	5.46	5.39	5.40	5.42
Monteith DS	-	-	-	2.24	2.24	2.24	2.25	2.26	2.26	2.26	2.27	2.27	2.27	2.28	2.29	2.30	2.31	2.34	2.36	2.38	2.40	2.37	2.38	2.39
Moosonee DS	-	-	-	8.69	8.67	8.66	8.67	8.66	8.67	8.68	8.69	8.69	8.67	8.68	8.69	8.71	8.73	8.78	8.83	8.89	8.94	8.84	8.85	8.86
Shiningtree DS	-	-	-	3.02	3.00	2.99	2.99	2.98	2.97	2.97	2.97	2.96	2.95	2.94	2.94	2.94	2.93	2.94	2.95	2.96	2.98	2.93	2.93	2.93
Smooth Rock Falls DS	-	-	-	1.93	1.92	1.92	1.92	1.91	1.91	1.91	1.91	1.90	1.90	1.90	1.90	1.90	1.90	1.91	1.93	1.94	1.95	1.92	1.92	1.92
Temagami DS 2	-	-	-	2.65	2.65	2.66	2.68	2.69	2.70	2.71	2.72	2.73	2.74	2.75	2.77	2.79	2.81	2.84	2.87	2.90	2.93	2.90	2.92	2.93
Verner DS	-	-	-	4.56	4.55	4.54	4.54	4.53	4.53	4.52	4.51	4.49	4.48	4.48	4.48	4.49	4.50	4.53	4.56	4.58	4.61	4.53	4.53	4.53
Warren DS	-	-	-	5.57	5.55	5.53	5.53	5.51	5.51	5.48	5.47	5.45	5.43	5.42	5.42	5.42	5.44	5.47	5.50	5.53	5.55	5.46	5.45	5.45

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Appendix B:

Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations	Voltages (kV)	Supply Circuits
1.	Ansonville TS	230/115	A9K A94N A5H A4H P91G A93I A8K
2.	Crystal Falls TS	230/44	H23S H24S
3.	Dymond TS	115/44	D4Z D3K D2L W71D
4.	Hearst TS	115/27.6	F1E
5.	Hunta SS	115	H7T A5H A4H H9K H6T D2H D3H
6.	Kapuskasing TS	230/115/28	H9K L21S K38S F1E
7.	Kirkland Lake TS	115/44	A8K A9K D3K K2 K4
8.	Little Long SS	230/44	L20D L21S
9.	Moosonee SS	115	T7M T8M M3K M9K
10.	North Bay TS	230/44	L5H
11.	Otter Rapids SS	115	T7M T8M R21D D6T
12.	Otto Holden TS	230/115/14	L5H D5H H4Z H23S H24S
13.	Pinard TS	500/230/115	L20D H22D R21D D3H D501P D4 D6T D23G D2H
14.	Porcupine TS	500/230/115	P91G P15T P7G D501P P13T P502X
15.	Ramore TS	115/27.6	A9K
16.	Spruce Falls TS	230/115/14	F1E K38S
17.	Timmins TS	115/27.6	H7T T2R H6T P15T T61S P13T
18.	Trout Lake TS	230/44	H24S W71D
19.	Widdifield SS	230	H23S H24S W71D

Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	A4H/A5H	Ansonville TS	Hunta SS	115
2.	A8K/A9K	Ansonville TS	Kirkland Lake TS	115
3.	D2H/D3H	Pinard TS	Hunta SS	115
4.	H6T/H7T	Hunta SS	Timmins TS	115
5.	P13T/P15T	Porcupine TS	Timmins TS	115
6.	T7M/T8M	Otter Rapids SS	Moosenee SS	115
7.	D2L	Dymond TS	Crystal Falls TS	115
8.	H9K	Hunta SS	Kapuskasing TS	115
9.	K2	Kirkland Lake TS	Radial	115
10.	K4	Kirkland Lake TS	Radial	115
11.	L1S	Martindale TS	Crystal Falls TS	115
12.	L5H	Crystal Falls TS	Otto Holden TS	115
13.	D3K	Dymond TS	Kirkland Lake TS	115
14.	P7G	Porcupine TS	Radial	115
15.	T61S	Timmins TS	Radial	115
16.	F1E	Kapuskasing TS	Hearst TS	115
17.	T2R	Timmins TS	Radial	115
18.	D23G	Pinard TS	Radial	230
19.	H22D	Pinard TS	Radial	230

20.	H23S/H24S	Martindale TS	Otto Holden TS	230
21.	K38S	Kapuskasing TS	Spruce Falls TS	230
22.	L20D	Pinard TS	Little Long SS	230
23.	L21S	Kapuskasing TS	Little Long SS	230
24.	P91G	Porcupine TS	Ansonville TS	230
25.	R21D	Otter Rapids SS	Radial	230
26.	W71D	Dymond TS	Widdfield SS	230
27.	P502X	Porcupine TS	Hanmer TS	500
28.	D501P	Porcupine TS	Pinard TS	500

Appendix C: Voltage Performance Analysis at Dymond TS

To address the on-going voltage issue due to operation of SC11& SC12 Capacitor banks at Dymond TS under N-1-1 contingency, Hydro One can de-rate the capacitor bank between 14-16MX. The capacitor banks can only be physically de-rated in the steps of 3MX.

Following table shows a PSSE simulation result with both capacitors de-rated to 15MX. (*Hydro One 2022 Winter Base case used for simulation purpose).*

Bus	Contingency														
	N-0					D3K O/S					D3K O/S +W71D				
		24+24 MX Caps		15+15 MX Caps			24+24 MX Caps		15+15 MX Caps			24+24 MX Caps		15+15 MX Caps	
	No Cap	ON	% Change	ON	% Change	No Cap	ON	% Change	ON	% Change	No Cap	ON	% Change	ON	% Change
Dymond TS 220	243.89	246.62	1.12	245.59	0.69	244.44	248.25	1.56	246.80	0.96					
Dymond TS 115	123.49	125.67	1.77	124.84	1.10	124.05	127.08	2.44	125.92	1.50	117.51	131.96	12.30	125.76	7.03
Dymond TS 44	46.35	47.11	1.63	46.82	1.02	46.55	47.59	2.25	47.19	1.39	44.28	49.37	11.50	47.15	6.47
Temagami 115	123.41	124.93	1.22	124.35	0.76	123.98	126.06	1.68	125.27	1.04	119.78	129.21	7.88	125.19	4.52

Capacitor bank switching under the studied scenario is infrequent due to the N-1-1 condition and voltage change limits shall take this into consideration. Sizing the capacitor banks between 14-16MX is shown to reduce the voltage change to reasonable limits based on the in frequent nature of the occurrence. This reduction allows for reactive support at Dymond TS to remain at a level that can still help with normal operations during non-contingency scenarios or system changes such as load growth. Simulation results will continue to be studied to correctly size the capacitor banks.

Appendix D: List of LDC's

Sr. No.	Local Distributor Company	Connection Type (TX/DX)
1.	Hydro One Distribution	TX/DX
2.	North Bay Hydro	DX
3.	Northern Ontario Wires Inc.	TX/DX
4.	Hearst Power Distribution Co.	DX
5.	Greater Sudbury Hydro Inc.	DX

Appendix E: List of Municipalities in the region

Sr. no.	Name of Municipality
1	Town of Hearst
2	Town of Kapuskasing
3	Town of Smooth Rock Falls
4	Town of Cochrane
5	Town of Foleyet
6	Town of Iroquois Falls
7	Town of Kirkland Lake
8	Town of Englehart.
9	Township of Black River
10	Township of Matheson
11	Township of East Ferris
12	City of North Bay
13	City of Temiskaming Shores
14	City of Timmins
15	Municipality of West Nipissing

Appendix F: Acronyms

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

PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station