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

Joanne Richardson
Director, Major Projects and Partnerships
C 416.902.4326
Joanne.Richardson@HydroOne.com

BY EMAIL AND RESS

August 29, 2023

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

Dear Ms. Marconi,

EB-2023-0198 – Hydro One Networks Inc. Leave to Construct Application – Waasigan Project – Update to Application and Evidence

Pursuant to s.92 of the Ontario Energy Board Act, 1998 (the “Act”), Hydro One Networks Inc. (“Hydro One”) seeks the Ontario Energy Board’s (“OEB”) approval for an Order or Orders granting leave to construct transmission facilities (“**Waasigan Project**” or “**Project**”) in the northwest Ontario regions of Thunder Bay, Rainy River and Kenora.

Additionally, pursuant to s.97 of the Ontario Energy Board Act, 1998, 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.

Hydro One is providing an update to its s.92 Application. The application’s prefiled evidence has been updated to include the final System Impact Assessment (“SIA”) Report (updated at Attachment 1 to Exhibit F), and the final Customer Impact Assessment report (updated at Attachment 1 to Exhibit G) to its leave to construct s.92 Application for the Waasigan Project, originally submitted July 31, 2023. Both reports were initially submitted as draft. Additionally, the Application’s Table of Contents (at Exhibit A, Tab 1, Schedule 1) has also been updated to recognise the final versions of both these reports.

The SIA, as received from the IESO and now included at Attachment 1 to Exhibit G, contains redacted information that has been removed due to reasons of confidentiality.

Additionally, Hydro One also respectfully requests the following information be kept confidential pursuant to Rule 10.01 of the Board’s Rules of Practice and Procedure, and consistent with the Board’s Practice Direction on Confidential Filings, as revised December 17, 2021:

Information / Report / Type	Specific Redactions	Presumptive Confidential Category
1) IESO Final System Impact Assessment ("SIA")	Exhibit F, Tab 1, Schedule 1, Attachment 1, Appendices B, C and D	Appendices B to D, inclusive, contain confidential information of the IESO, the connection applicant, the transmitter and, potentially, other third parties, including information that, if disclosed, could reasonably be expected to pose a potential security threat to the integrated power system, the IESO administered markets, or those of neighbouring jurisdictions.
2) IESO Need Report – Appendix F	Exhibit B, Tab 3, Schedule 1, Attachment 9, Appendix F, for specific information contains on Pages; 1, 2, 4 - 6, 32 - 76, and associated Appendices B-1 and B-2.	The redacted content concerns provincial electric vehicle (EV) charging demand forecasting, which is not relevant to the Application (per Practice Direction, section 11).

The final unredacted SIA, for which it is seeking confidential treatment, has been submitted using the Board's Regulatory Electronic Submission System.

Hydro One has filed a redacted text-searchable electronic version of the complete application that encompasses these changes using the OEB's Regulatory Electronic Submission System.

Sincerely,

Joanne Richardson

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

Joanne Richardson
Director, Major Projects and Partnerships
C 416.902.4326
Joanne.Richardson@HydroOne.com

BY EMAIL AND RESS

August 16, 2023

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

Dear Ms. Marconi,

EB-2023-0198 – Hydro One Networks Inc. Leave to Construct Application – Waasigan Project – Application and Evidence – Update to Exhibit B-7-1

Hydro One is providing additional evidence to its leave to construct s.92 Application for the Waasigan Project, originally submitted July 31, 2023. The specific update is in the form of supplemental material, a report from Atrium Economics, pertaining to evidence provided in Exhibit B, Tab 7, Schedule 1.

The Atrium Economics report has been added to the Application as Attachment 1 to Exhibit B, Tab 7, Schedule 1. Hydro One has also updated the Application's Exhibit List, at Exhibit A, Tab 1, Schedule 1, to identify its inclusion.

Hydro One has submitted a copy of the full Application as a text-searchable electronic version of the complete application that encompasses these changes using the Board's Regulatory Electronic Submission System for public use.

Sincerely,

Joanne Richardson

Hydro One Networks Inc.
483 Bay Street
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Joanne Richardson
Director, Major Projects and Partnerships
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BY EMAIL AND RESS

July 31, 2023

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

Dear Ms. Marconi,

EB-2023-0198 – Hydro One Networks Inc. Leave to Construct Application – Waasigan Project – Application and Evidence

Pursuant to s.92 of the Ontario Energy Board Act, 1998 (the "Act") Hydro One Networks Inc. ("Hydro One") seeks the Ontario Energy Board's ("OEB") approval for an Order or Orders granting leave to construct transmission facilities ("**Waasigan Project**" or "**Project**") in the northwest Ontario regions of Thunder Bay, Rainy River and Kenora.

Additionally, pursuant to s.97 of the Ontario Energy Board Act, 1998, 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.

Hydro One also respectfully requests the following information be kept confidential pursuant to Rule 10.01 of the Board's Rules of Practice and Procedure, and consistent with the Board's Practice Direction on Confidential Filings, as revised December 17, 2021:

Information / Report / Type	Specific Redactions	Presumptive Confidential Category
1) IESO Draft System Impact Assessment ("SIA")	Exhibit F, Tab 1, Schedule 1, Attachment 1, Appendices B, C and D	Appendices B to D, inclusive, contain confidential information of the IESO, the connection applicant, the transmitter and, potentially, other third parties, including information that, if disclosed, could reasonably be expected to pose a potential security threat to the integrated power system, the IESO administered markets, or those of neighbouring jurisdictions.

2) IESO Need Report – Appendix F	Exhibit B, Tab 3, Schedule 1, Attachment 9, Appendix F, for specific information contains on Pages; 1, 2, 4 - 6, 32 - 76, and associated Appendices B-1 and B-2.	The redacted content concerns provincial electric vehicle (EV) charging demand forecasting, which is not relevant to the Application (per Practice Direction, section 11).

The SIA being provided in this Application's prefiled evidence, from the IESO, is 'draft'. Hydro One expects to receive the final version of the SIA from the IESO within 3-4 weeks of the filing date. Once the final SIA is received the CIA can be finalised. Thereafter, Hydro One will submit both final versions of the SIA and CIA into the application evidence materials, which is expected to occur prior to the Notice of Application being posted.

A redacted electronic copy of the application and evidence has been submitted using the Board's Regulatory Electronic Submission System for public use.

Sincerely,

Joanne Richardson

Connecting Today.
Powering Tomorrow.

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

July 26, 2023

VIA Applicant

Ms. Nancy Marconi
Registrar
Ontario Energy Board
27th Floor 2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Marconi,

Re: Independent Electricity System Operator
The Waasigan Project EB-2023-0198 (the "Application")

Confidentiality Request

In accordance with Rule 10 of the OEB's *Rules of Practice and Procedure* and the OEB's *Practice Direction on Confidential Filings* (the "Practice Direction"), the IESO requests confidential treatment for Appendix "F", Posterity Group's Electric Vehicle & Mining Sector Market Study Final Report (the "Posterity Group Report") of the IESO's evidence in the Application.

The IESO requests confidential treatment for the redacted portions of the enclosed (non-confidential) version of the Posterity Group Report because the content concerns provincial electric vehicle (EV) charging demand forecasting, which is not relevant to the Application (Practice Direction, section 11).

A table specifying the rationale for the EV-related information requested to be redacted is enclosed as Appendix "A" hereto. The IESO notes that the items that have been redacted from the Posterity Group Report that are the subject of this confidentiality request, have no bearing in the consideration of any issues in this proceeding nor have these items been provided to the Applicant. The non-relevance of the EV-related content is further described in Appendix "D" of the IESO's evidence in the Application.

A copy of this letter, and the enclosed copy of the Posterity Group Report (redacted, non-confidential), has been provided by the IESO to the Applicant for filing. The IESO also wishes to file the non-redacted, confidential copy of the Posterity Group Report required by paragraph

11.1.1(a) of the Practice Direction and seeks the OEB's direction with respect to the appropriate protocol for such filing.

Yours truly,

Beverly Nollert

Senior Manager, Regulatory Affairs

Encl. Posterity Group Report, Redacted (Non-Confidential)

cc: Mr. Patrick Duffy, Stikeman Elliott (email)

Appendix A

CONFIDENTIALITY REQUEST TABLE

Appendix F, Posterity Group Report

Page	**Rationale for Redaction**
1	EV content – Relevance per section 11 of the Practice Direction
2	EV content – Relevance per section 11 of the Practice Direction
4	EV content – Relevance per section 11 of the Practice Direction
5	EV content – Relevance per section 11 of the Practice Direction
6	EV content – Relevance per section 11 of the Practice Direction
32-76	EV content – Relevance per section 11 of the Practice Direction
B1	EV content – Relevance per section 11 of the Practice Direction
B2	EV content – Relevance per section 11 of the Practice Direction

1

EXHIBIT LIST

Exhibit	Tab	Schedule	Attachment	Contents
A				
	1	1		Exhibit List
	1	2		Mapping of OEB Filing Guidelines to Hydro One's Exhibit List
	1	3		List of Acronyms and Abbreviations
B				
	1	1		Application
	2	1		Project Overview
	2	1	1	Schematic Diagram of Proposed Line Facilities
	2	1	2	Schematic Diagram of Proposed Lakehead TS Configuration
	2	1	3	Schematic Diagram of Proposed Mackenzie TS Configuration
	2	1	4	Schematic Diagram of Proposed Dryden TS Configuration
	3	1		Evidence In Support of Need
	3	1	1	Order-in-Council
	3	1	2	Deputy Minster of Energy Letter to Hydro One
	3	1	3	OEB Decision Order re: Transmission License Amendment
	3	1	4	Hydro One's Transmission License – as amended
	3	1	5	IESO Letter of Direction - 2014

	3	1	6	IESO Letter of Direction – Phase 1 - 2018
	3	1	7	IESO Letter of Direction – Phase 1 – 2022
	3	1	8	IESO Letter of Direction – Phase 2 - 2023
	3	1	9	IESO Report – Waasigan Transmission Line Project: Need, Alternatives, and Recommendation – July 26, 2023
	4	1		Categorization
	5	1		Cost Benefit Analysis and Options
	6	1		Benefits
	7	1		Apportioning Project Costs and Risks
	7	1	1	Atrium Economics' Report - Overhead Capitalization Methodology for ECI-EPC Contracted Projects
	8	1		Network Reinforcement
	9	1		Transmission Rate Impact
	10	1		Revenue Requirement Information and Deferral Account Requests
	11	1		Project Schedule
C				
	1	1		Physical Design
	1	1	1	Tower Design Along Route
	1	1	2	Map Layouts of Project Impacted Transformer Stations
	2	1		Maps
	2	1	1	Notice Map

	2	1	2	Detailed Route Map
	2	1	3	Individual Property Maps
D				
	1	1		Operational Details
E				
	1	1		Land Matters
	1	1	1	Early Access Agreement
	1	1	2	Agreement for Temporary Rights
	1	1	3	Damage Claim Agreement/Waiver
	1	1	4	Option to Purchase a Limited Interest – Easement
	1	1	5	Compensation and Incentive Agreement – Easement
	1	1	6	Option to Purchase – Fee Simple
	1	1	7	Compensation and Incentive Agreement – Fee Simple
	1	1	8	Off Corridor Access
	1	1	9	Option to Purchase a Limited Interest – Easement with a Voluntary Buyout Offer
	1	1	10	List of Properties and Permits associated with the Project route
	1	1	11	Ministry of Northern Development and Mines Delegation Letter – October 25, 2018
	1	1	12	Ministry of Northern Development and Mines Amended Delegation Letter – April 15, 2020

F				
	1	1		System Impact Assessment
	1	1	1	Final System Impact Assessment
G				
	1	1		Customer Impact Assessment
	1	1	1	Final Customer Impact Assessment
H				
	1	1		Regional and Bulk Planning
	1	1	1	Integrated Regional Resource Plan - Northwest Region – (January 2023)

MAPPING OEB CHAPTER 4 FILING REQUIREMENTS TO THE S92 EXHIBIT LIST

OEB Chapter 4 Filing Requirement	Hydro One S.92 Application Exhibit
4.3.1 – The Index	
	A-01-01 – Exhibit List
	A-01-02 – Mapping OEB Chapter 4 Filing Requirements to S92 Exhibit List
	A-01-03 – List of Acronyms and Abbreviations
4.3.2 – The Application	
4.3.2.1 – Administrative Matters	B-01-01 – Application
4.3.2.2 – Project Overview	B-02-01 – Project Overview
4.3.2.3 – Evidence in Support of Need for the Project	B-03-01 – Evidence in Support of Need
4.3.2.4 – Project Categorization	B-04-01 – Project Categorization
4.3.2.5 – Analysis of Alternatives	B-05-01 – Cost Benefit Analysis and Options B-06-01 – Qualitative & Quantitative Benefits
4.3.2.6 – Project Costs	B-07-01 – Apportioning Project Costs and Risks B-09-01 – Transmission Rate Impact Assessment
4.3.2.7 – Risks	B-07-01 – Apportioning Project Costs and Risks
4.3.2.8 – Comparable Projects	B-07-01 – Apportioning Project Costs and Risks
4.3.2.9 – Connection Projects that Also Address a Network Need	B-08-01 – Network Reinforcement Requiring Network Reinforcement
4.3.2.10 – Connection Projects Requiring Network Reinforcement	B-08-01 – Network Reinforcement Requiring Network Reinforcement
4.3.2.11 – Transmission Rate Impact Assessment	B-09-01 – Transmission Rate Impact Assessment
4.3.2.12 – Establishment of Deferral Accounts	B-10-01 – Revenue Requirement Information and Deferral Account Requests
4.3.2.13 – Capital Contribution Period	B-09-01 – Transmission Rate Impact Assessment B-10-01 – Revenue Requirement Information and Deferral Account Requests
4.3.2.14 – Project Schedule	B-11-01 – Project Schedule

4.3.3 – Project Details	
4.3.3.1 – The Route	E-01-01 – Land Matters
4.3.3.2 – Description of the Physical Design	C-01-01 – Description of the Physical Design
4.3.3.3 – Maps	C-02-01 - Maps
4.3.4 – Design Specification and Operational Data	C-01-01 – Description of the Physical Design D-01-01 – Operational Details
4.3.4.1 – Operational Details	D-01-01 – Operational Details
4.3.5 – Land Matters	
4.3.5.1 – Description of Land Rights Required	E-01-01 – Land Matters
4.3.5.2 – Land Acquisition Process	E-01-01 – Land Matters
4.3.5.3 – Land-related Forms	E-01-01 – Land Matters
4.3.5.4 – Early Access to Land	E-01-01 – Land Matters
4.3.6 – System Impact Assessment	F-01-01 – System Impact Assessment
4.3.7 – Customer Impact Assessment	G-01-01 – Customer Impact Assessment
4.3.8 – Regional and Bulk Planning	
4.3.8.1 – Integrated Regional Resource Plan	H-01-01 – Regional and Bulk Planning B-03-01 – Need Evidence
4.3.8.2 – Regional Infrastructure Plan	H-01-01 – Regional and Bulk Planning
4.3.8.3 – Bulk System Plan	H-01-01 – Regional and Bulk Planning

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
ATP	Affiliate Transmission Projects
C	Celsius
CIA	Customer Impact Assessment
CSA	Canadian Standards Association
EA	Environmental Assessment
ECI	Early Contractor Involvement
ECI-EPC	Refers to an ECI delivery model that engages the services of an external OE and the services of EPC contractors.
EDWR Account	Externally Driven Work Regulatory Account
EPC	Engineering, Procurement and Construction
ESR	Environmental Study Report
EWT	East-West Tie
EWT Partnership	East-West Tie Limited Partnership
FACTS	Flexible Alternating Current Transmission System
GLP	Gwayakocchigewin Limited Partnership
HOEP	Hourly Ontario Energy Price
HR	Human Resources
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
ISOC	Integrated System Operating Center
IT	Information Technology
kcmil	Kilo-circular mils *(unit of measure of the area of a wire with a circular cross section)*
km	Kilometer
kV	Kilovolt
LDMLFN	Lac des Mille Lacs First Nation
LTE	Long Term Emergency rating
LTEPs	Long Term Energy Plans
MECP	Ministry of the Environment, Conservation and Parks
MENDM	Ministry of Energy, Northern Development & Mines

Acronym or Abbreviation	**Acronym or Abbreviation Expansion**
MNO	Metis Nation of Ontario
MNRF	Ministry of Natural Resources and Forestry
MVAR	Megavolt-ampere of Reactive power
MW	Megawatt
MWH *(or MWHR)*	Megawatt-hour
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NPV	Net Present Value
OE	Owner's Engineer
OEB	Ontario Energy Board (the Board)
OIC	Order in Council
OM&A	Operations, Maintenance and Administrative costs
OPGW	Optical Ground Wire
ORTAC	Ontario Resource and Transmission Assessment Criteria
PHASE 1	Refers to the "Waasigan Phase 1 Transmission Line" – a new 230 kV double-circuit transmission line that will span from the existing Lakehead TS to the existing Mackenzie TS.
PHASE 2	Refers to the "Waasigan Phase 2 Transmission Line" – a new 230 kV single-circuit transmission line that will span from the existing Mackenzie TS to the existing Dryden TS.
PV	Present Value
RAS	Remedial Action Scheme
RFP	Request for Proposal
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
RPP	Regulated Price Plan
SCADA	Supervisory Control and Data Acquisition system
SIA	System Impact Assessment
STATCOM	Static Synchronous Compensator
SVC	Static VAR Compensator
TS	Transformer Station
TSC	Transmission System Code
TSP	Transmission System Plan
TWM	Transfer West into Mackenzie TS
Upper Canada 2	Upper Canada Transmission 2, Inc.
UTR	Uniform Transmission Rates
Watay Power	Wataynikaneyap Power GP Inc.

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF an Application by Hydro One Networks Inc. pursuant to s. 92 of the *Ontario Energy Board Act, 1998* (the "Act") for an Order or Orders granting leave to construct transmission facilities ("**Waasigan Project**" or "**Project**") in the northwest Ontario regions of Thunder Bay, Rainy River and Kenora.

AND IN THE MATTER OF an Application by Hydro One Networks Inc. 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

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

2. Hydro One hereby applies to the OEB pursuant to s. 92 of the Act for an Order or Orders granting leave to construct approximately 360km of electricity transmission facilities in the regions of Thunder Bay, Rainy River and Kenora, Ontario.

3. The Waasigan Project has been declared a priority project for Hydro One to develop and seek approvals for by the Minister of Energy. The OIC from the Minister of Energy is attached as **Exhibit B, Tab 3, Schedule 1, Attachment 1.** These facilities are required to increase long-term transmission capacity in northwest Ontario as recommended by the IESO in their report entitled the *Waasigan Transmission Line Project: Need, Alternatives, and Recommendation.*

A copy of this report is attached as **Exhibit B, Tab 3, Schedule 1, Attachment 9.** The Project has been identified as a non-discretionary development project in **Exhibit B, Tab 4, Schedule 1**.

4. In developing the Project, Hydro One is committed to working with Indigenous communities in a spirit of cooperation and shared responsibility. We acknowledge that Indigenous communities have unique historic and cultural relationships with their land and a unique knowledge of the natural environment. Forging meaningful relationships with Indigenous communities based upon trust, mutual respect, and accountability is vital to advancing reconciliation and achieving Hydro One’s corporate objectives. Hydro One has been engaging with Indigenous communities since 2018 in the development process and will continue to engage with communities throughout the life cycle of the Project.

5. In acknowledgement of Indigenous rights and to ensure the advancement of the Project and in the spirit of advancing action on reconciliation, Hydro One has conducted extensive economic discussions with impacted Indigenous communities. Through a community led approach to engagement, topics identified as being priorities of communities included environmental protection, employment, training, contracting and economic participation and having meaningful participation and input in decision making on the Project. Though Hydro One has been directed to undertake the development component of this Project, the transmission line facilities comprising the Project will become owned by a future limited partnership which will offer a 50% equity ownership to 9 First Nation partners. Gwayakocchigewin Limited Partnership, or GLP, represents eight of the nine First Nations partnering with Hydro One on the Waasigan Transmission Line Project. The GLP First Nations include Wabigoon Lake Ojibway Nation, Eagle Lake First Nation, Lac La Croix First Nation, Fort William First Nation, Seine River First Nation, Lac Seul First Nation, Nigigoonsiminikaaning First Nation, and the Ojibway Nation of Saugeen. The ninth First Nation partner is Lac des Mille Lacs First Nation. Gwayakocchigewin

means "making decisions the right way". GLP's goal is to achieve meaningful economic participation for its First Nations, while protecting the lands, waters, and cultural values potentially impacted by the Waasigan Transmission Line Project.

6. As of the time of this Application, formation and structuring of the limited partnership has not been finalized. As the limited partnership is not yet formed, Hydro One is not currently able to provide commercial details. However, those details will be provided to the OEB once the limited partnership is formed through all the OEB-required asset transfer and transmission licence application processes. Until such time, line work costs associated with the construction of the Project facilities will reside in the OEB-approved ATP regulatory account[1] and will not form part of Hydro One's rate base. For reference purposes, further information on the regulatory account is provided at **Exhibit B, Tab 10, Schedule 1**.

7. The Waasigan Project is comprised of two sections of 230 kV overhead transmission lines spanning between Lakehead TS, Mackenzie TS and Dryden TS, totaling a distance of approximately 360km. Construction of the transmission facilities will occur in two phases. Construction of Phase 1 will include a double-circuit 230 kV transmission line spanning approximately 190km between Lakehead TS (in the municipality of Shuniah) to Mackenzie TS (in the town of Atikokan). Construction of Phase 2 will include a single circuit 230 kV line transmission line spanning approximately 170km between Mackenzie TS to Dryden TS (in the city of Dryden). An overview map depicting the location of the Project, and each Phase, is attached at **Exhibit C, Tab 2, Schedule 1, Attachment 1**[2] and schematic diagrams of the transmission lines and stations for

[1] EB-2021-0169.
[2] Hydro One's intention in providing this Map is that it be used by the OEB for the purposes of the Notice Map.

Phase 1 and 2 can be found at **Exhibit B, Tab 2, Schedule 1, Attachments 1** through **4**.

8. The proposed in-service date for Phase 1 is December 2025, assuming an OEB approval of this Application prior to February 2024, allowing construction to commence in March 2024. The proposed in-service date for Phase 2 is December 2027, assuming a construction commencement date of January 2026. A project schedule is provided at **Exhibit B, Tab 11, Schedule 1**.

9. New permanent land rights along the proposed line's route are required to accommodate the proposed transmission line facilities between Lakehead TS and Dryden TS. No additional property rights are required for any of the three transformer stations included in the Project's scope. Temporary rights for construction purposes, including laydown areas, may also be required at specific locations along the corridor. Further information regarding the real estate needs to complete the Project are provided in **Exhibit E, Tab 1, Schedule 1**.

10. The IESO has completed a final SIA. The SIA concludes that the Project is expected to have no material adverse impacts 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 attached as **Exhibit F, Tab 1, Schedule 1, Attachment 1.**

11. Hydro One has completed a Final CIA in accordance with Hydro One's connection procedures. The results confirm that there are not expected to be impacts on area customers because of the Project. A copy of the CIA is attached as **Exhibit G, Tab 1, Schedule 1, Attachment 1**.

12. 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 and operate, the Project.

13. The forecast total capital cost of the Project transmission facilities is $1,200 million[3]. Further information pertaining to these costs is found at **Exhibit B, Tab 7, Schedule 1.**

14. The expected rate impact associated with the Waasigan Project (using 2023 OEB-approved uniform transmission rates as filed in **Exhibit B, Tab 9, Schedule 1)**, is an increase of 6.33%, because of the increases in the network pool rate, and a 0.41%, or $0.56/month, increase on a typical average residential consumer's electricity bill.

15. This Application is also seeking approval of the forms of the agreement offered, or to be offered, to affected landowners, pursuant to s. 97 of the Act. The majority of these agreements are in the same form as previously approved in prior Hydro One leave to construct proceedings. Any agreements that have not been previously approved by the OEB, or have been altered from their last approval, have been explicitly identified in the Application. The forms of the applied-for agreements are found as attachments to **Exhibit E, Tab 1, Schedule 1**.

16. 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.

17. Given the information provided in the prefiled evidence, Hydro One submits that the Project is in the public interest. The Project meets the need of the transmission system and improves quality of service and reliability with minimal impact on price.

---

[3] There will be an additional $0.1M of OMA removal costs associated with constructing this Project.

18. 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:**

Carla Molina
Sr. Regulatory Coordinator
Hydro One Networks Inc.

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

Telephone:	(416) 345-5317
Fax:	(416) 345-5866
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b) **The Applicant's Counsel:**

Gordon M. Nettleton
Partner
McCarthy Tétrault

Mailing Address:
Suite 5300, 66 Wellingtons Street West
TD Bank Tower Box 48
Toronto, Ontario M5K 1E6

Telephone:	(403) 260-3622
Fax:	(403) 260-3501
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c) Monica Caceres
Assistant General Counsel
Hydro One Networks Inc.

Mailing Address:
8th Floor, South Tower
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Telephone:	(647) 505-3341
Fax:	(416) 345-6972
Electronic access:	monica.caceres@hydroone.com

This page has been left blank intentionally.

PROJECT OVERVIEW DOCUMENTS

Hydro One is seeking approval to construct and operate transmission facilities to meet the requirements set out by the IESO in its letter[1] to Hydro One dated May 3, 2022, and a subsequent letter dated April 24, 2023[2]. This Application also satisfies the OIC[3] and the direction of the Minister of Energy in its letter to Hydro One[4], as amended into Hydro One's transmission licence[5] (Section 19.6), to develop and seek all necessary approvals for a new 230 kV double-circuit transmission line. The project consists of a new 230 kV double-circuit transmission line that will span from the existing Lakehead TS to the existing Mackenzie TS (also referred to herein as the "Waasigan Phase 1 Transmission Line", or "Phase 1"), and a new 230 kV single-circuit transmission line from the existing Mackenzie TS to the existing Dryden TS (also referred to herein as the "Waasigan Phase 2 Transmission Line", or "Phase 2"), including associated station facilities at these terminal stations. The proposed Project's major facilities, along with their general locations, that are subject to section 92 approval, are summarized as follows:

- Approximately 190km of 230 kV double-circuit transmission line from Lakehead TS to the Mackenzie TS on a combination of, i) existing 230 kV transmission corridors that require widening to accommodate the new facilities, and ii) additional new corridor lands. Phase 1's expected in-service date is December 2025.
- Approximately 170km 230 kV single-circuit transmission line from Mackenzie TS to Dryden TS on a combination of, i) existing 230 kV transmission corridors that require widening to accommodate the new facilities, and ii) additional new corridor lands. Phase 2's expected in-service date is December 2027.

[1] Exhibit B, Tab 3, Schedule 1, Attachment 7
[2] Exhibit B, Tab 3, Schedule 1, Attachment 8
[3] Exhibit B, Tab 3, Schedule 1, Attachment 1
[4] Exhibit B, Tab 3, Schedule 1, Attachment 2
[5] Exhibit B, Tab 3, Schedule 1, Attachment 4

- Terminal station modifications at Lakehead TS, Mackenzie TS, and Dryden TS to accommodate the new Phase 1 and Phase 2 proposed transmission circuits.
- The Waasigan Transmission Line is located in the traditional territories of the Treaty #3 and Robinson-Superior First Nations and traverses the Northwestern Ontario Métis Community and Northern Lake Superior Métis Community.

A map indicating the geographic location of the proposed Phase 1 and Phase 2 facilities is provided at **Exhibit C, Tab 2, Schedule 1, Attachment 1,** which is also intended to be used by the OEB as this Application's Notice Map.

Schematic diagrams of the proposed line and station facilities are provided at **Exhibit B, Tab 2, Schedule 1, Attachments 1 through 4**.

The Waasigan Project, was previously known as the "Northwest Bulk Transmission Line" and was identified in the Ontario Government's 2013[6] and 2017[7] LTEPs as a priority project to:

- increase electricity supply to the region west of Thunder Bay;
- provide a means for new customers and growing loads to be served with clean and renewable sources that comprise Ontario's supply mix; and,
- enhance the potential for development and connection of renewable energy facilities.

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

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[6] 2013 LTEP – https://files.ontario.ca/books/ltep_2013_english_web.pdf
[7] 2017 LTEP – https://files.ontario.ca/books/ltep2017_0.pdf

PHASE 1 – 230 KV DOUBLE-CIRCUIT TRANSMISSION LINE BETWEEN LAKEHEAD TS AND MACKENZIE TS

Overhead Transmission Line

There is an existing 230 kV double-circuit transmission line connecting Lakehead TS and Mackenzie TS, circuit nomenclature being A21L and A22L. With the completion of Phase 1, there will be one additional 230 kV double-circuit transmission line[8] between Lakehead TS and Mackenzie TS, whose intended circuit nomenclature will be A30L and A31L. The total route length from Lakehead TS to Mackenzie TS is approximately 190 km. Additionally, new OPGW fiber will be installed atop the new circuits to allow for telecommunication as part of the new line protection scheme. The proposed transmission circuit route passes through the two northern Ontario districts of Thunder Bay and Rainy River. The circuit will have a minimum rating under following conditions: summer continuous 880A; summer long term emergency 1100A; winter continuous 1020A; and winter long term emergency 1230A and utilize ACSR of 795 kcmil sizing.

Lakehead TS Line Termination and Switching Facilities

At the Lakehead TS, new and modified station assets will be required, such as high voltage buses, diameters, breakers, and disconnect switches, and will all be located within Hydro One’s currently owned property, via an expanded station footprint, which is required to accommodate the additional termination of the two new Phase 1 230 kV circuits. More specifically, Phase 1 work at Lakehead TS will require new lines, breakers, and bus protections, as well as modifications to select existing lines, buses and bus protections. Furthermore, the Phase 1 requires the installation of new shunt reactor with a breaker and disconnect switch, and the relocation and re-termination of an existing 230 kV circuit (nomenclature M37L), to facilitate the connection of new Phase 1 circuits.

[8] Refer to the schematic at **Exhibit B, Tab 2, Schedule 1, Attachment 1**

Modifications and additions to protection and control, SCADA system, metering, and the AC/DC station service at Lakehead TS, are required to provide protection, control, and status of the new facilities. More specifically, Lakehead TS Phase 1 work will require new line, breaker and bus protections, as well as modifications to select existing line, breaker, and bus protections.

At Lakehead TS a new voltage control switching scheme will be implemented to coordinate and optimize control of existing and new reactive power devices as recommended in the IESO's SIA[9]. In addition, the existing Northwest RAS will be modified to incorporate the Project.

A schematic diagram showing the proposed configuration at Lakehead TS is provided at **Exhibit B, Tab 2, Schedule 1, Attachment 2**.

Mackenzie TS Line Termination and Switching Facilities

At the Mackenzie TS, new and modified station assets are required, such as, a new relay building, high voltage buses, diameters, breakers, and disconnect switches, within the station property to accommodate the termination of the two new 230 kV circuits (nomenclature of circuits will be A30L and A31L). In addition, two existing Hydro One 230 kV circuits (nomenclatures F25A and D26A), and one 115 kV (nomenclature A3M) require re-termination within the station to facilitate the connection of the new Phase 1 circuits. Additionally, two new shunt reactors with associated breakers and disconnect switches are required for Phase 1 completion.

Modifications and additions to protection and control, SCADA, metering, and AC/DC station service at Mackenzie TS, are required to provide protection, control, and the operating status of the new facilities. More specifically, Phase 1 work at Mackenzie TS will require new lines, breakers, and bus protections, as well as modifications to select existing lines, buses, and bus protections. A schematic diagram showing the proposed

[9] Exhibit F, Tab 1, Schedule 1, Attachment 1

configuration at Mackenzie TS is provided at **Exhibit B, Tab 2, Schedule 1, Attachment 3**. Work at Mackenzie TS will also include a new voltage control switching scheme that will be implemented to coordinate and optimize control of existing and new reactive power devices as recommended in the IESO's SIA.

PHASE 2 – 230 KV SINGLE-CIRCUIT TRANSMISSION LINE BETWEEN MACKENZIE TS AND DRYDEN TS

Overhead Transmission Line

There is an existing 230 kV single-circuit transmission line connecting Mackenzie TS to Dryden TS, nomenclature D26A. Phase 2 of the Project consists of constructing an additional 230 kV single-circuit transmission line[10] (nomenclature will be D32A) connecting Mackenzie TS and Dryden TS. The total route length of the Phase 2 single-circuit transmission line from Mackenzie TS to Dryden TS is approximately 170km. Additionally, new OPGW fiber will be installed atop the new circuit route to allow for telecommunication as part of the new line protection scheme. The preferred route passes through the districts of Rainy River and Kenora. The circuit will have a minimum rating under following conditions: summer continuous 880A; summer long term emergency 1100A; winter continuous 1020A; and winter long term emergency 1230A and utilize ACSR of 795 kcmil sizing.

Mackenzie Line Termination and Switching Facilities

At Mackenzie TS, new and modified station assets will be required, such as breakers, and disconnect switches, within the station property to accommodate the termination of the new 230 kV circuit towards Dryden TS. Additionally, Phase 2 Project scope work includes work that will see existing 230 kV circuits (nomenclatures F25A and D26A) move from the circuits being carried on common structures, to individual structures such that F25A and D26A circuits will share not more than 1.6 km of common structures emanating from Mackenzie TS.

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[10] Refer to the schematic at **Exhibit B, Tab 2, Schedule 1, Attachment 1**

Modifications to SCADA, metering, and AC/DC station service at Mackenzie TS, are required to provide the protection, control and status of the new Phase 2 facilities. More specifically, Mackenzie TS Phase 2 work will include installation of new line, breaker, and bus protections, as well as modifications to existing bus protections. A schematic diagram showing the proposed configuration at Mackenzie TS is provided at **Exhibit B, Tab 2, Schedule 1, Attachment 3**.

Dryden TS Line Termination and Switching Facilities

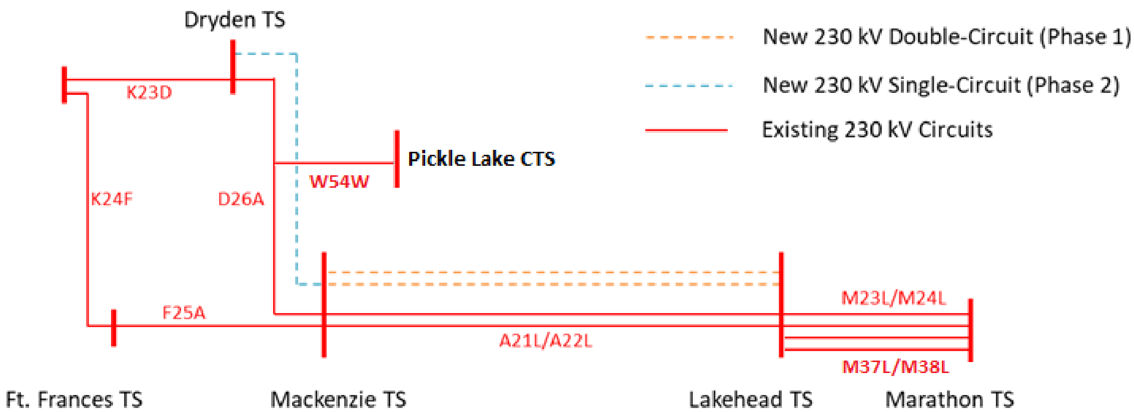
At Dryden TS new and modified station assets will be required, such as, high voltage buses, diameters, breakers, and disconnect switches, within the station property to accommodate the termination of the new 230 kV circuit. Additionally, a new dynamic reactive compensation device with associated breaker and disconnect switch is to be provisioned on the new diameter in accordance with direction from the IESO[11].

Modifications SCADA, metering, and AC/DC station service at Dryden TS, are required to provide the protection, control, and status of the new Phase 2 facilities. More specifically, Dryden TS Phase 2 work will include the installation of new line, breakers, and bus protections, as well as modifications to existing buses and bus protections. A schematic diagram showing the proposed configuration at Dryden TS is provided at **Exhibit B, Tab 2, Schedule 1, Attachment 4**.

[11] Exhibit F, Tab 1, Schedule 1, Attachment 1

SCHEMATIC DIAGRAM OF PROPOSED LINE FACILITIES

PROPOSED FACILITIES:
WAASIGAN TRANSMISSION LINE SCHEMATIC DIAGRAM

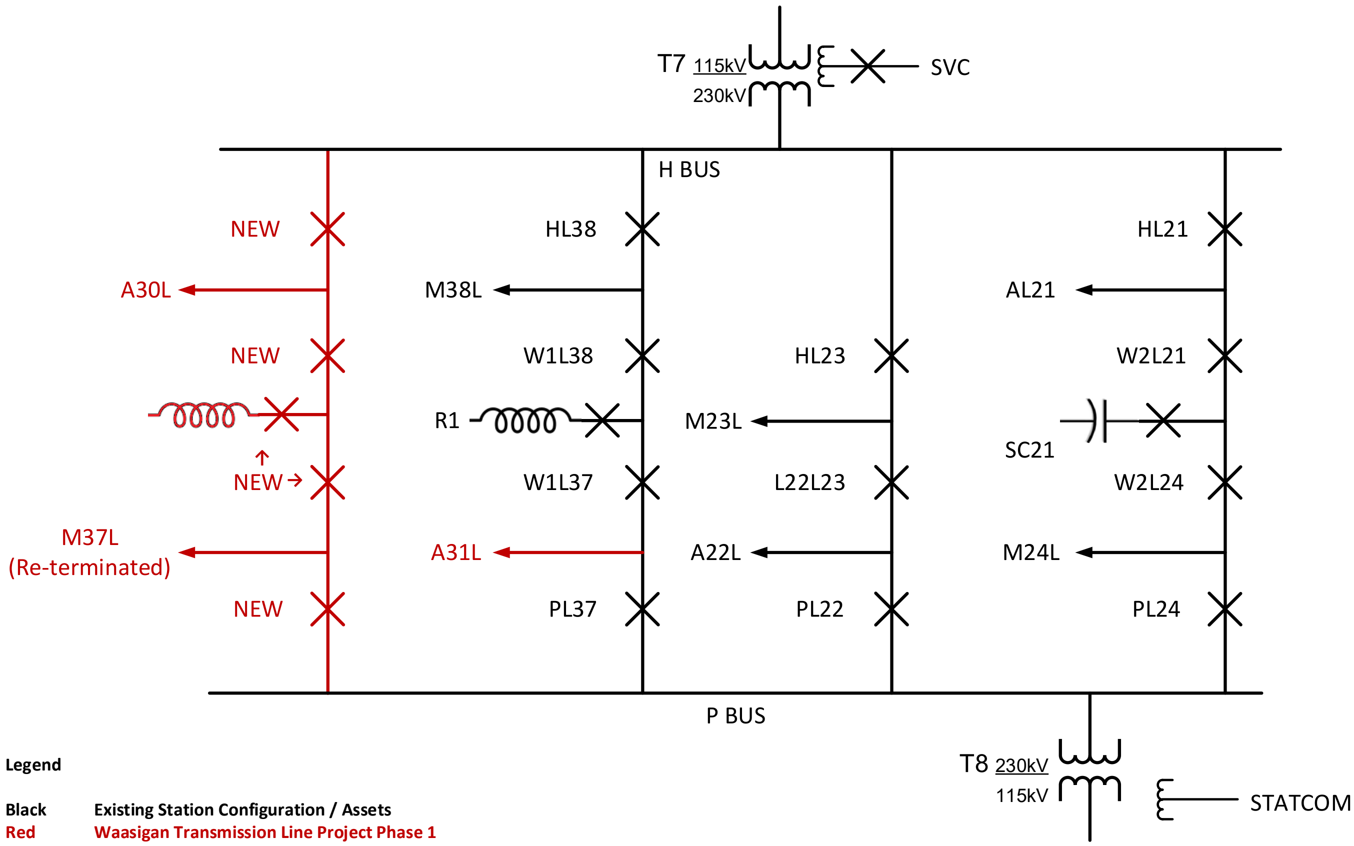


SCHEMATIC DIAGRAM OF PROPOSED LAKEHEAD TS CONFIGURATION

PROPOSED FACILITIES

230 kV LAKEHEAD TS SIMPLIFIED SCHEMATIC DIAGRAM

(Red coloured lines represent new proposed facilities of Phase 1 in this Application)



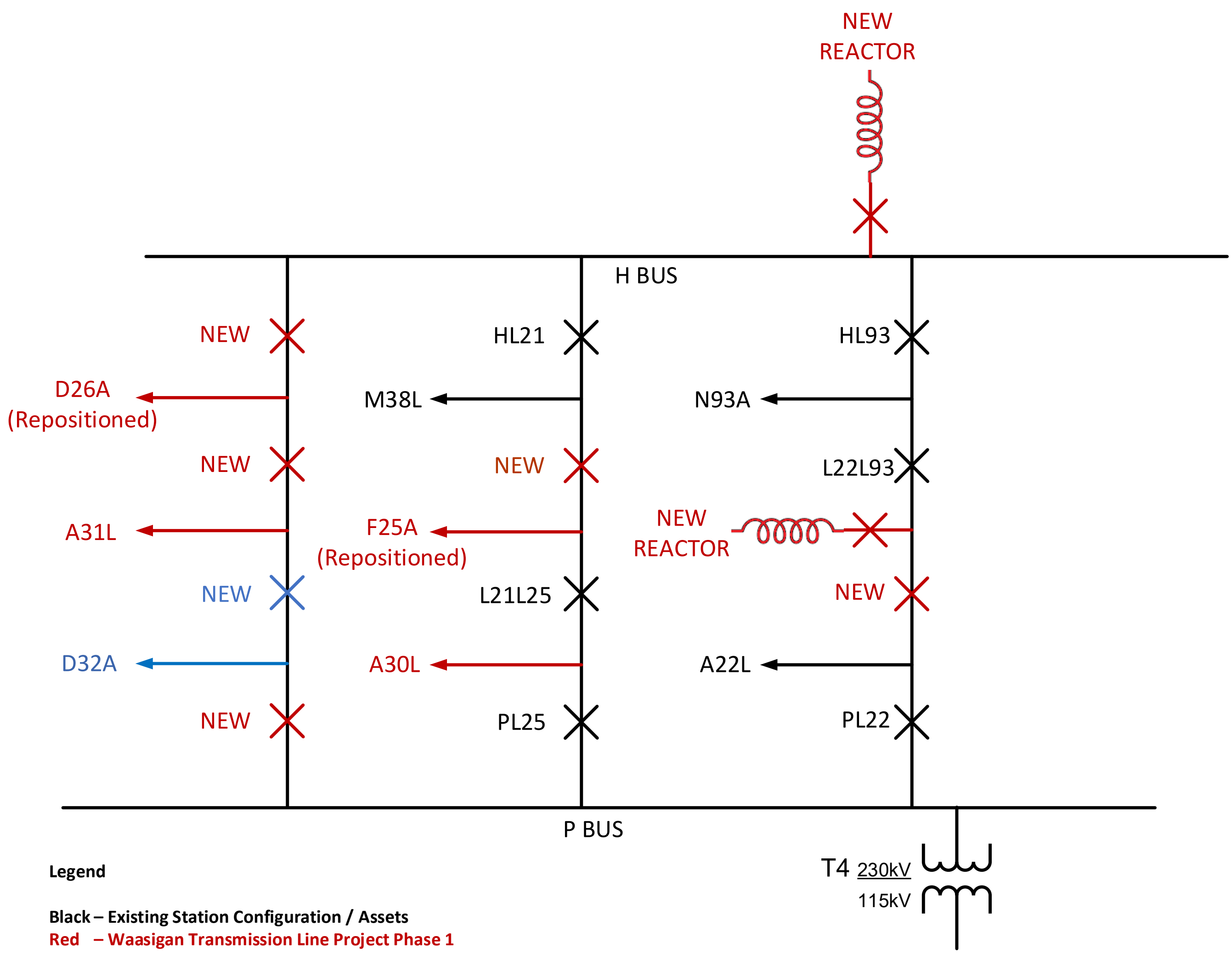
SCHEMATIC DIAGRAM OF
PROPOSED MACKENZIE TS CONFIGURATION

PROPOSED FACILITIES

230 kV MACKENZIE TS SIMPLIFIED SCHEMATIC DIAGRAM

(Red coloured lines represent new proposed facilities of Phase 1 in this Application)

(Blue coloured lines represent new proposed facilities of Phase 2 in this Application)

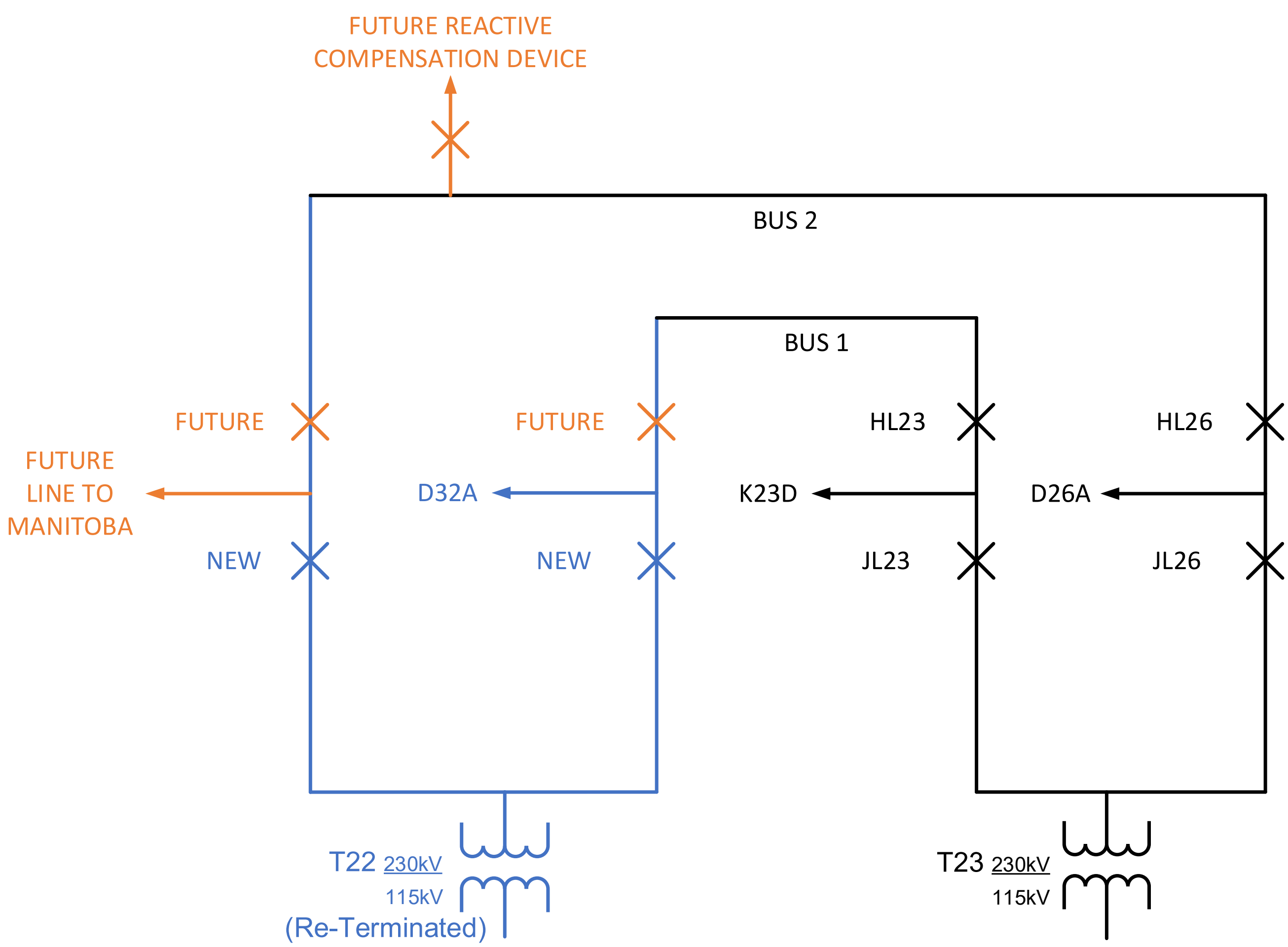


SCHEMATIC DIAGRAM OF PROPOSED DRYDEN TS CONFIGURATION

PROPOSED FACILITIES

230 kV DRYDEN TS SIMPLIFIED SCHEMATIC DIAGRAM

(Blue coloured lines represent new proposed facilities of Phase 2 in this Application)
(Orange coloured lines represent potential future facilities that are not part of this Application)



Legend

Black **Existing Station Configuration / Assets**
Blue **Waasigan Transmission Line Project Phase 2**
Orange **Waasigan Transmission Line Project Phase 3 (Preliminary and Informational Only)**

EVIDENCE IN SUPPORT OF NEED

This Exhibit should be read in conjunction with IESO report, "Waasigan Transmission Line Project: Need, Alternatives, and Recommendation" Report (referenced herein as the "IESO Report"), as included at **Attachment 9**, which evidences Project need.

The Project, initially referred to as the Northwest Bulk Transmission Line Project, was identified in the Ontario government's 2013[1] and 2017[2] LTEPs as a priority project[3] to address emerging needs in the area west of Thunder Bay. The 2017 LTEP divided the Project into three phases:

- Phase 1: a new double-circuit 230 kV line from the Lakehead TS in Thunder Bay to the Mackenzie TS in Atikokan;
- Phase 2: a new single-circuit 230 kV line from the Mackenzie TS in Atikokan to the Dryden TS in Dryden; and
- Phase 3: a new line from Dryden to the Manitoba border through Kenora.

In particular, the Project was identified as a means to support economic development in the west of Thunder Bay area, most notably from the projected growth of the mining sector, by increasing supply and reliability capability through the release of existing transmission constraints. Most recently, the Project was identified in the Ontario government's *Powering Ontario's Growth* report as one of the electricity system upgrades being undertaken to unlock opportunities in Northern Ontario. [4]

On December 11, 2013, the Minister of Energy, with the approval of the Lieutenant Governor in Council, issued an Order in Council[5] ("OIC") and directive under section 28.6 of the *OEB Act, 1998*, declaring that development work proceed to expand Ontario's transmission system in order to better serve the expected growth in the area west of

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[1] Long-Term Energy Plan 2013
[2] Long-Term Energy Plan 2017
[3] Long-Term Energy Plan 2013, p. 51
[4] Power Ontario's Future (2023), p. 70
[5] Exhibit B, Tab 3, Schedule 1, Attachment 1

Thunder Bay. In conjunction with the OIC, the Deputy Minister of Energy provided a letter[6] to Hydro One, dated December 11, 2013, outlining the Ministry of Energy's expectations of Hydro One regarding the Project's development. Thereafter, on January 9, 2013, the OEB issued a Decision and Order[7] (EB-2013-0437) updating Hydro One's transmission license[8] (ET-2003-0035) requiring, amongst other things, that Hydro One:

- Work with the IESO (at the time the Ontario Power Authority) to establish the scope and timing of the transmission project referred to in the OIC.
- Develop and seek approvals for the Project (then, Northwest Bulk Transmission Line Project)[9], which shall be composed of the expansion or reinforcement of a portion or portions of the electricity transmission network in the area west of Thunder Bay"[10].

The IESO described the need for the Project in its first letter to Hydro One dated October 1, 2014[11], and again in more detail through subsequent letters dated October 24, 2018[12], May 3, 2022[13], and April 24, 2023[14]. In its April 2023 letter, the IESO recommended that:

> "…construction be staged to prioritize Phase 1 coming in service as close to the end of 2025 as possible (as previously recommended), with Phase 2 coming in service as soon as practical after Phase 1"[15].[16]

Specifically, as it related to Project need, and consistent with the 2017 LTEP[17], the IESO's May 3, 2022 and April 24, 2023 letters described that the Project was required to:

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[6] Exhibit B, Tab 3, Schedule 1, Attachment 2
[7] Exhibit B, Tab 3, Schedule 1, Attachment 3
[8] Exhibit B, Tab 3, Schedule 1, Attachment 4
[9] Subsequently renamed the 'Waasigan Project'.
[10] Exhibit B, Tab 3, Schedule 1, Attachment 1, Pg. 2
[11] Exhibit B, Tab 3, Schedule 1, Attachment 5
[12] Exhibit B, Tab 3, Schedule 1, Attachment 6
[13] Exhibit B, Tab 3, Schedule 1, Attachment 7
[14] Exhibit B, Tab 3, Schedule 1, Attachment 8
[15] Exhibit B, Tab 3, Schedule 1, Attachment 8, Pg. 3
[16] The IESO has not identified a need for Phase 3 and is not recommending that it be developed at this time
[17] Long-Term Energy Plan 2017, p. 51

- increase the electricity supply to the region west of Thunder Bay;
- provide a means for new customers and growing loads to be served with clean and renewable sources that comprise Ontario's supply mix; and,
- enhance the potential for development and connection of renewable energy facilities.

The IESO Report[18] reinforces the requirements outlined in its letters to Hydro One and further confirmed the need for the Project, stating:

> "The Region's electricity system today is very close to its capacity and, due to the size of proposed mining projects, if even one of the larger projects develops and seeks grid connection in the Region, there will be an immediate need for additional supply capacity. The risk associated with not building that capacity now is that new customers may not be able to connect or reliability in the Region may be degraded. Both these outcomes can be expected to stifle further growth."[19]

On that basis, the IESO Report also recommended that the Project proceed, concluding that:

> "… the IESO recommends the Project as the only alternative that is feasible and implementable to supply forecast electricity demand growth in the Region…"[20]

The IESO's recommendation was supported by the findings of its planning analysis that demonstrated current transmission infrastructure is insufficient today to meet projected supply needs under the four scenarios: "Business as Usual", "Limited Growth", "Moderate Growth" and "Strong Growth". The results of the IESO's planning analysis that

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[18] Exhibit B, Tab 3, Schedule 1, Attachment 9
[19] Exhibit B, Tab 3, Schedule 1, Attachment 9 pg. 18
[20] Exhibit B, Tab 3, Schedule 1, Attachment 9 pg. 19

demonstrate the near term need for the Project are fully described on pages 3 through 11 of the IESO Report.

Facility Limitations and Capacity

The IESO Report indicates that the Project would provide enough additional capacity to supply demand growth under all above listed forecast scenarios. In a Strong Growth scenario, additional dynamic reactive support would be required, as indicated in the IESO's 2018 and 2023 letters to Hydro One and the IESO Report.

Relationship to Other Electricity System Benefits

The Project, in addition to addressing the identified needs, would provide further system benefits including addressing constraints on eastbound transfers out of the west of Thunder Bay region that currently prevents local generation and imports from Manitoba and Minnesota from providing greater value to the Ontario system, and limits new resource development west of Thunder Bay. Project benefits are described in more detail on pages 18 and 19 of the IESO Report[21].

[21] Exhibit B, Tab 3, Schedule 1, Attachment 9

ORDER-IN-COUNCIL

Ontario
Executive Council
Conseil des ministres

Order in Council
Décret

DEC 11 2013

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

Sur la recommandation du soussigné, le lieutenant-gouverneur, sur l'avis et avec le con- sentement du Conseil des ministres, décrète ce qui suit:

WHEREAS the Ontario Government finds it prudent to initiate development work to expand Ontario's transmission system in order to better serve the expected growth in the area west of Thunder Bay given anticipated growth in electrical load, to promote the use of clean and renewable energy sources from Ontario's supply mix, and to enhance opportunities for the development and connection of new renewable generation facilities over the long term;

AND WHEREAS the electricity transmission network in the area west of Thunder Bay is composed of the high-voltage circuits connecting Thunder Bay to Kenora, through Atikokan, Dryden, and Fort Frances;

AND WHEREAS it is intended that the development work focus on the expansion or reinforcement of a portion or portions of that electricity transmission network in the area west of Thunder Bay (the "Northwest Bulk Transmission Line Project");

AND WHEREAS it is anticipated that the Ontario Power Authority ("OPA") would make recommendations concerning the specific scope and timing of the above-noted project in accordance with its statutory mandate, objects and responsibilities pursuant to the *Electricity Act, 1998*, and as a function of its ongoing electricity resource planning activities;

AND WHEREAS the Government has determined that the preferred manner of proceeding is to require Hydro One Networks Inc. to undertake the development of the Northwest Bulk Transmission Line Project including to undertake any and all steps which are deemed to be necessary and desirable in order to seek required approvals;

AND WHEREAS the Minister of Energy has, with the approval of the Lieutenant Governor in Council, the authority to issue Directives pursuant to section 28.6 of the *Ontario Energy Board Act, 1998*, which relate to the connection of renewable energy generation facilities to a transmitter's transmission system or to a distributor's distribution system;

NOW THEREFORE the Directive attached hereto, is approved.

Recommended: ______________________
Minister of Energy

Concurred: ______________________
Chair of Cabinet

Approved and Ordered: NOV 27 2013
Date

____
Lieutenant Governor

O.C./Décret 1701/2013

Certified to be a true copy
Anna Valero
Deputy Clerk, Executive Council

MINISTER'S DIRECTIVE

TO: THE ONTARIO ENERGY BOARD

I, Bob Chiarelli, hereby direct the Ontario Energy Board ("Board") pursuant to section 28.6 of the *Ontario Energy Board Act, 1998* as follows:

1. The Board shall amend the licence conditions of Hydro One Networks Inc.'s ("Hydro One") electricity transmission licence to include a requirement that Hydro One proceed to do the following related to the expansion or reinforcement of its transmission system, in order to accommodate load due to forecast demand growth over the long term, to promote the use of clean and renewable energy sources from Ontario's supply mix, and to enhance opportunities for the development and connection of new renewable generation facilities over the long term:

   (i) Develop and seek approvals for the Northwest Bulk Transmission Line Project, which shall be composed of the expansion or reinforcement of a portion or portions of the electricity transmission network in the area west of Thunder Bay.

   (ii) Immediately work in co-operation with the Ontario Power Authority ("OPA") to establish the scope and timing for the Northwest Bulk Transmission Line Project. The scope and timing of the project to be carried out by Hydro One shall accord with the recommendations of the OPA.

   It is anticipated that the OPA's recommendations will be made in the course of the OPA's transmission planning activities, conducted in accordance with its statutory mandate, objects and responsibilities under the *Electricity Act, 1998*, including with any transmission planning activities identified in any direction issued, or to be issued, by the Minister of Energy to the OPA pursuant to Part II.2 of that Act.

2. The Board shall make the amendments to the electricity transmission licence of Hydro One without holding a hearing.

Minister of Energy

DEPUTY MINSTER OF ENERGY
LETTER TO HYDRO ONE

Ministry of Energy

Office of the Deputy Minister

Hearst Block, 4th Floor
900 Bay Street
Toronto, ON M7A 2E1
Tel: 416-327-6758
Fax: 416-327-6755

Ministère de l'Énergie

Bureau du sous-ministre

Édifice Hearst, 4e étage
900, rue Bay
Toronto, ON M7A 2E1
Tél: 416-327-6758
Téléc.: 416-327-6755

Ontario

December 11, 2013 Carm

DEC 11 2013

Mr. Carmine Marcello
President & CEO
Hydro One Inc.
483 Bay Street
North Tower
15th Floor
Toronto, Ontario
M5G 2P5

JAN 07 2014

Dear Carmine:

As you are aware, the new Northwest Bulk Transmission Line project (the "Project") has been identified as a priority transmission project for Ontario's transmission system in the Ministry's recently issued Long Term Energy Plan (2013). In furtherance of the project, the Ministry has now received the necessary approvals required in order to assign the development work for the Project, which includes engineering work and preparation of regulatory approvals, to Hydro One.

In terms of timing, the transmission line would not be built until the conclusion of the development work and the receipt of all required regulatory approvals.

However, a key initial step in the line's development would be the definition of the scope and timing for construction of the line, to be provided by the Ontario Power Authority in the course of its ongoing planning work. Given your corporation's important role in developing transmission assets for Ontario, I am confident that Hydro One has the experience and resources sufficient to develop the Project in a timely manner and to bring it into service in accordance with expected need dates.

I am also in the process of requesting Infrastructure Ontario (IO) to provide advice and services to Hydro One, the project sponsor, as needed to support the development phase of the Project. Given IO's experience and expertise with financing and procurement for public infrastructure projects, Hydro One should continue working with IO so that the Project can be developed cost effectively. It is desired that IO provide advice regarding a competitive procurement framework for the Project. IO's scope of services would, for example, include strategic and financial advice regarding the procurement, evaluation and contracting processes, project management or other areas of project development, construction or financing.

As a next step, and assuming all necessary approvals and authorities are in place, it is expected that Hydro One provide an initial report back to the Ministry of Energy on the progress of its discussions with IO within 60 days of IO having received the approvals referred to above. It is also expected that Hydro One be prepared to provide the Ministry with subsequent progress reports once discussions with IO have sufficiently progressed, which would be expected to include an assessment of the costs and anticipated benefits of this process.

I look forward to hearing the results of your progress.

Sincerely,

Serge Imbrogno

Serge Imbrogno
Deputy Minister

OEB DECISION ORDER RE:
TRANSMISSION LICENSE AMENDMENT

EB-2013-0437

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

AND IN THE MATTER OF a Directive issued by the Minister of Energy to the Ontario Energy Board under section 28.6 of the *Ontario Energy Board Act, 1998* and approved by the Lieutenant Governor in Council on November 27, 2013 as Order in Council No. 1701/2013.

By delegation, before: Lynne Anderson

DECISION AND ORDER
January 9, 2014

Under section 28.6(1) of the *Ontario Energy Board Act, 1998* (the "Act"), the Minister of Energy (the "Minister") may issue directives to the Ontario Energy Board (the "Board") requiring the Board to take such steps as are specified in the directive relating to the connection of renewable energy generation facilities to a transmitter's transmission system or a distributor's distribution system. As stated in section 28.6(2) of the Act, such a directive may among other things require the Board to amend the licence conditions of a transmitter to require the transmitter to take the actions specified in the directive in relation to its transmission system, including enhancing, re-enforcing or expanding that system. In accordance with section 28.6(3) of the Act, such a directive may specify whether the Board is to hold a hearing for the purposes of implementing the directive.

On December 16, 2013, the Board received a directive issued by the Minister under section 28.6 of the Act (the "Transmission Directive"). The Transmission Directive was approved by the Lieutenant Governor in Council on November 27, 2013 as Order in Council No. 1701/2013. The Transmission Directive requires the Board to amend the transmission licence of Hydro One Networks Inc. ("Hydro One") in relation to the development of a certain transmission project “related to the expansion or reinforcement of [Hydro One’s] transmission system, in order to accommodate load due to forecast demand growth over the long term, to promote the use of clean and renewable energy sources from Ontario’s supply mix, and to enhance opportunities for the development and connection of new renewable generation facilities over the long term”. Order in Council No. 1701/2013 and the Transmission Directive refer to the transmission network in the area west of Thunder Bay, which the Order in Council notes is composed of high-voltage circuits connecting Thunder Bay to Kenora, through Atikokan, Dryden and Fort Frances.

The Transmission Directive describes at a high level the transmission project to be developed by Hydro One, and requires that the scope and timing of the project be established by Hydro One in accordance with the recommendations of the Ontario Power Authority (the “OPA”). To that end, the Transmission Directive also requires that Hydro One immediately work in co-operation with the OPA.

The Transmission Directive is attached as Appendix A to this Decision and Order. In accordance with the Transmission Directive, the Board is required to amend Hydro One’s transmission licence without a hearing.

Hydro One will be required to report to the Board on progress towards the implementation of the conditions being added to its transmission licence today in furtherance of the Transmission Directive, as set out below.

THE BOARD THEREFORE ORDERS THAT:

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

    19.5 Immediately following January 9, 2014 the Licensee shall, for the purposes of accommodating load due to forecast demand growth over the long term, promoting the use of clean and renewable energy sources from Ontario’s supply mix, and enhancing opportunities for the development and connection of new renewable generation facilities over the long term, work in co-operation with the Ontario Power Authority to establish the scope and timing of the transmission project referred to in paragraph 19.6.

19.6 The Licensee shall develop and seek approvals for the expansion or reinforcement of a portion or portions of the Licensee's electricity transmission network in the area west of Thunder Bay (the "Northwest Bulk Transmission Line Project"). The scope and timing of the Northwest Bulk Transmission Line Project shall be in accordance with the recommendations of the Ontario Power Authority made in the course of the Ontario Power Authority's transmission planning activities conducted in accordance with its statutory mandate, objects and responsibilities under the *Electricity Act, 1998*, including with any transmission planning activities identified in any direction issued, or to be issued, by the Minister of Energy to the Ontario Power Authority pursuant to Part II.2 of the *Electricity Act, 1998.*

2. Hydro One shall file with the Board, within fourteen days of receipt, a copy of any recommendations received from the OPA related to the Northwest Bulk Transmission Line Project.

3. Hydro One shall file with the Board, within 30 days of completion, a document describing the scope and timing of the Northwest Bulk Transmission Line Project established in co-operation with the OPA.

DATED at Toronto, January 9, 2014

ONTARIO ENERGY BOARD

Original signed by

Lynne Anderson
Managing Director, Applications and Regulatory Audit

Appendix A

to

Decision and Order dated January 9, 2014

EB-2013-0437

Order in Council No. 1701/2013

and

Minister of Energy's Directive to the Ontario Energy Board

[See separate document attached]

Ontario
Executive Council
Conseil des ministres

Order in Council
Décret

DEC 1 1 2013

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

Sur la recommandation du soussigné, le lieutenant-gouverneur, sur l'avis et avec le con- sentement du Conseil des ministres, décrète ce qui suit:

WHEREAS the Ontario Government finds it prudent to initiate development work to expand Ontario's transmission system in order to better serve the expected growth in the area west of Thunder Bay given anticipated growth in electrical load, to promote the use of clean and renewable energy sources from Ontario's supply mix, and to enhance opportunities for the development and connection of new renewable generation facilities over the long term;

AND WHEREAS the electricity transmission network in the area west of Thunder Bay is composed of the high-voltage circuits connecting Thunder Bay to Kenora, through Atikokan, Dryden, and Fort Frances;

AND WHEREAS it is intended that the development work focus on the expansion or reinforcement of a portion or portions of that electricity transmission network in the area west of Thunder Bay (the "Northwest Bulk Transmission Line Project");

AND WHEREAS it is anticipated that the Ontario Power Authority ("OPA") would make recommendations concerning the specific scope and timing of the above-noted project in accordance with its statutory mandate, objects and responsibilities pursuant to the *Electricity Act, 1998*, and as a function of its ongoing electricity resource planning activities;

AND WHEREAS the Government has determined that the preferred manner of proceeding is to require Hydro One Networks Inc. to undertake the development of the Northwest Bulk Transmission Line Project including to undertake any and all steps which are deemed to be necessary and desirable in order to seek required approvals;

AND WHEREAS the Minister of Energy has, with the approval of the Lieutenant Governor in Council, the authority to issue Directives pursuant to section 28.6 of the *Ontario Energy Board Act, 1998,* which relate to the connection of renewable energy generation facilities to a transmitter's transmission system or to a distributor's distribution system;

NOW THEREFORE the Directive attached hereto, is approved.

Recommended: ______________
Minister of Energy

Concurred: ______________
Chair of Cabinet

Approved and Ordered: NOV 2 7 2013
Date

____
Lieutenant Governor

O.C./Décret 1701/2013

Certified to be a true copy
Anna Valero
Deputy Clerk, Executive Council

MINISTER'S DIRECTIVE

TO: THE ONTARIO ENERGY BOARD

I, Bob Chiarelli, hereby direct the Ontario Energy Board ("Board") pursuant to section 28.6 of the *Ontario Energy Board Act, 1998* as follows:

1. The Board shall amend the licence conditions of Hydro One Networks Inc.'s ("Hydro One") electricity transmission licence to include a requirement that Hydro One proceed to do the following related to the expansion or reinforcement of its transmission system, in order to accommodate load due to forecast demand growth over the long term, to promote the use of clean and renewable energy sources from Ontario's supply mix, and to enhance opportunities for the development and connection of new renewable generation facilities over the long term:

   (i) Develop and seek approvals for the Northwest Bulk Transmission Line Project, which shall be composed of the expansion or reinforcement of a portion or portions of the electricity transmission network in the area west of Thunder Bay.

   (ii) Immediately work in co-operation with the Ontario Power Authority ("OPA") to establish the scope and timing for the Northwest Bulk Transmission Line Project. The scope and timing of the project to be carried out by Hydro One shall accord with the recommendations of the OPA.

   It is anticipated that the OPA's recommendations will be made in the course of the OPA's transmission planning activities, conducted in accordance with its statutory mandate, objects and responsibilities under the *Electricity Act, 1998*, including with any transmission planning activities identified in any direction issued, or to be issued, by the Minister of Energy to the OPA pursuant to Part II.2 of that Act.

2. The Board shall make the amendments to the electricity transmission licence of Hydro One without holding a hearing.

Minister of Energy

HYDRO ONE'S

TRANSMISSION LICENSE – AS AMENDED

Ontario

Electricity Transmission Licence

ET-2003-0035

Hydro One Networks Inc.

Valid Until

December 2, 2023

Original signed by

____

Peter Fraser
Vice President, Industry Operations and Performance
Ontario Energy Board

Date of Issuance: December 3, 2003
Date of Last Amendment: November 26, 2015

Ontario Energy Board	Commission de l’énergie de l’Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
27th. Floor	27e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

LIST OF AMENDMENTS

Board File No.	Date of Amendment
EB-2002-0501	August 11, 2004
EB-2011-0055	February 28, 2011
EB-2009-0437	January 9, 2014
EB-2015-0262	November 26, 2015
EB-2015-0270	November 26, 2015

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1 Definitions

In this Licence:

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

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

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

"**Board or OEB**" means the Ontario Energy Board;

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

"**Licensee**" means Hydro One Networks Inc.;

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

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

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

"**small-scale renewable energy generation facility**" means a renewable energy generation facility that is a "capacity allocation exempt small embedded generation facility" or a "micro-embedded generation facility" as those terms are defined in the Distribution System Code as it read on February 28, 2011;

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

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

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

2 Interpretation

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

3 Authorization

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

4 Obligation to Comply with Legislation, Regulations and Market Rules

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

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the “Codes”) approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the Licensee are set out in Schedule 2 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; and

b) the Transmission System Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Requirement to Enter into an Operating Agreement

6.1 The Licensee shall enter into an agreement (“Operating Agreement”) with the IESO providing for the direction by the IESO of the operation of the Licensee’s transmission system. Following a request made by the IESO, the Licensee and the IESO shall enter into an Operating Agreement within a period of 90 business days, unless extended with leave of the Board. The Operating Agreement shall be filed with the Board within ten (10) business days of its completion.

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

7 Obligation to Provide Non-discriminatory Access

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

8 Obligation to Connect

8.1 If a request is made for connection to the Licensee’s transmission system or for a change in the capacity of an existing connection, the Licensee shall respond to the request within 30 business days.

8.2 The Licensee shall process connection requests in accordance with published connection procedures and participate with the customer in the IESO’s Connection Assessment and approval process in accordance with the Market Rules, its Rate Order(s) and the Transmission System Code.

8.3 An offer of connection shall be consistent with the terms of this Licence, the Rate Order, the Market Rules and the Transmission System Code, and Schedules 3 and 4 of this Licence.

8.4 An offer of connection shall be consistent with the terms of this Licence, the Market Rules, the Rate Order, and the Transmission System Code.

8.5 The terms of such offer to connect shall be fair and reasonable.

8.6 The Licensee shall not refuse to make an offer to connect unless it is permitted to do so by the Act or any Codes, standards or rules to which the Licensee is obligated to comply with as a condition of this Licence.

9 Obligation to Maintain System Integrity

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

10 Transmission Rates and Charges

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

11 Separation of Business Activities

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

12 Expansion of Transmission System

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

12.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its transmission system in accordance with Market Rules and the Transmission System Code, in such a manner as the Board may determine.

12.3 The Licensee shall use its best efforts to expand inter-tie capacity to neighbouring jurisdictions by approximately 2000 MW by May 1, 2005.

12.4 Paragraph 12.3 in no way limits the obligation on the Licensee to obtain all necessary approvals including leave of the Board under Section 92 of the Act, where such leave is required.

12.5 The Licensee shall provide information to the Board as soon as practicable following May 1, 2005 or at an earlier date in order that the Board may determine whether or not, as of the end of such 36 month period, the Licensee has used its best efforts to expand inter-tie capacity to neighbouring jurisdictions by approximately 2000 MW.

13 Provision of Information to the Board

13.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

13.2 Without limiting the generality of paragraph 13.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) business days past the date upon which such change occurs.

14 Restrictions on Provision of Information

14.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator, obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

14.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

14.3 Information regarding consumers, retailers, wholesalers or generators may be disclosed where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

14.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

14.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information is not be used for any other purpose except the purpose for which it was disclosed.

15 Term of Licence

15.1 This Licence shall take effect on December 3, 2003 and expire on December 2, 2023. The term of this Licence may be extended by the Board.

16 Transfer of Licence

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

17 Amendment of Licence

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

18 Fees and Assessments

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

19 Expansion and Upgrading of Transmission System Further to Ministerial Directive

19.1 The Licensee shall, for the purposes of accommodating the safe connection of renewable energy generation facilities, immediately following February 28, 2011 work in co-operation with the Ontario Power Authority to establish the scope and timing of the transmission projects referred to in paragraphs 19.2 and 19.3.

19.2 The Licensee shall develop and seek approvals for the following transmission projects, the scope and timing of which shall be in accordance with the recommendations of the Ontario Power Authority made in the course of the Ontario Power Authority's transmission planning activities conducted in accordance with its objects, as well as those identified in a Directive issued to the Ontario Power Authority by the Minister of Energy on February 17, 2011 under section 25.30 of the *Electricity Act, 1998*:

a) upgrade one or more existing transmission lines west of the City of London; and

b) a new transmission line west of the City of London.

19.3 The Licensee shall develop and implement the following transmission projects, the scope and timing of which shall be in accordance with the recommendations of the Ontario Power Authority made in the course of the Ontario Power Authority's transmission planning activities conducted in accordance with its objects, as well as those identified in a Directive issued to the Ontario Power Authority by the Minister of Energy on February 17, 2011 under section 25.30 of the *Electricity Act, 1998*:

a) one or more devices to enhance transfer capability, such as series or static var compensation or other similar devices, in Southwestern Ontario; and

b) increase short circuit and/or transformer capacity at up to fifteen of the Licensee's transmission stations during the forty-eight month period beginning February 28, 2011 , to enable the connection of small-scale renewable energy generation facilities.

19.4 Paragraph 19.3 in no way limits the obligation of the Licensee to obtain all necessary approvals for the transmission projects referred to in that paragraph.

19.5 Immediately following January 9, 2014 the Licensee shall, for the purposes of accommodating load due to forecast demand growth over the long term, promoting the use of clean and renewable energy sources from Ontario's supply mix, and enhancing opportunities for the development and connection of new renewable generation facilities over the long term, work in co-operation with the Ontario Power Authority to establish the scope and timing of the transmission project referred to in paragraph 19.6.

19.6 The Licensee shall develop and seek approvals for the expansion or reinforcement of a portion or portions of the Licensee's electricity transmission network in the area west of Thunder Bay (the "Northwest Bulk Transmission Line Project"). The scope and timing of the Northwest Bulk Transmission Line Project shall be in accordance with the recommendations of the Ontario Power Authority made in the course of the Ontario Power Authority's transmission planning activities conducted in accordance with its statutory mandate, objects and responsibilities under the *Electricity Act, 1998*, including with any transmission planning activities identified in any direction issued, or to be issued, by the Minister of Energy to the Ontario Power Authority pursuant to Part II.2 of the *Electricity Act, 1998.*

20 Communication

20.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

20.2 All official communication relating to this Licence shall be in writing.

20.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender=s transmission report.

21 Copies of the Licence

21.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

SCHEDULE 1 SPECIFICATION OF TRANSMISSION FACILITIES

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

1. The transmission system and facilities of Hydro One Networks Inc. are depicted in the attached diagram and include transmission lines, transformation stations and all associated facilities. Subject to section 13.2, Hydro One may alter this diagram from time to time and shall file it with the Board, upon receipt of which the updated diagram shall be deemed to be the specification of transmission facilities under this schedule.

SCHEDULE 2 LIST OF CODE EXEMPTIONS

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

1. The Licensee is exempted from Section 1.2.1 of Schedule E of Appendix 1 of the Transmission System Code so as to allow the Licensee:

    - to enter into a connection agreement with certain proposed customers on terms and conditions other than those set forth in the said section 1.2.1; and
    - to amend connection agreements already entered into by the licensee with customers, such that they may be amended to contain terms and conditions other than those set forth in the said section 1.2.1.

2. The modifications to the connection agreement are attached as Schedules 3 and 4 to this Licence. Schedule 3 contains changes needed to address legacy system configuration issues as well as operating concerns affecting all generating stations owned by OPG and Bruce Power. Schedule 4 contains changes needed to comply with the operational requirements of nuclear generating facilities, facilitate compliance with Power Reactor Operating Licences, issued by the Canadian Nuclear Safety Commission ("CNSC").

SCHEDULE 3
GENERATION RELATED CLAUSES SUPERSEDING THE CONNECTION AGREEMENT AND SCHEDULES

The purpose of this addendum is to capture generation related amendments that have been agreed to by the parties. In any circumstance where there is an inconsistency between the terms of the Connection Agreement and the terms of this Addendum, the terms of this Addendum shall prevail.

Insofar as this Agreement differs from the standard Transmission Connection Agreement issued by the OEB, this Agreement is subject to the approval of the Ontario Energy Board ("OEB"); and to the extent, if any, that the OEB fails to give such approval:

(a) this Agreement shall be amended as determined by the OEB; or

(b) if the OEB fails to give such approval but does not itself amend this Agreement, the parties shall amend this Agreement pursuant to the directions of the OEB, and the revised amendments shall be subject to the approval of the OEB.

<u>Amendments to the Main Agreement</u>

RECITAL

In accordance with its licence and the Market Rules, the Transmitter has agreed to offer, and the Customer has agreed to accept Connection Service, on the terms and conditions of this Agreement.

Replace by:

In accordance with its licence and the Market Rules, the Transmitter has agreed to offer, and the Customer has agreed to accept, in respect of those facilities defined in Schedule A, Connection Service, on the terms and conditions of this Agreement.

1 DEFINITIONS

1.14 "non-financial Default" means the following:

1.14.1. any breach of a term or condition of the Code or the Connection Agreement other than a financial default unless the breach occurs as a direct result of an emergency;

1.14.2. a licensed Party's ceasing to hold a licence; and

1.14.3. ...an Insolvency Event.

Replace by:

1.14 "non-financial Default" means the following:

1.14.1. any breach of a term or condition of the Code or the Connection Agreement other than a financial default unless the breach occurs as a direct result of an emergency; or

1.14.2. a licensed Party's ceasing to hold a licence; or

1.14.3. an Insolvency Event.

5 EQUIPMENT STANDARDS

5.1 The Transmitter and the Customer shall ensure that their respective new or altered equipment connected to the transmission system: (1) meets requirements of the Ontario Electrical Safety Authority; (2) conform to relevant industry standards including, but not limited to, CSA International, the Institute of Electrical and Electronic Engineers (IEEE), the American National Standards Association (ANSI), and the International Electrotechnical Commission (IEC); (3) conforms to good utility practices.

Replace by:

The Transmitter and the Customer shall ensure that their respective new or altered equipment connected to the transmission system: (1) meets requirements of the Ontario Electrical Safety Authority unless otherwise exempted; (2) conforms to relevant industry standards including, but not limited to, CSA International, the Institute of Electrical and Electronic Engineers (IEEE), the American National Standards Association (ANSI), and the International Electrotechnical Commission (IEC); (3) conforms to good utility practices.

5.2 The minimum general performance standards for all equipment connected to the transmission system are set out in Appendix 2 of the Code. The Transmitter shall provide the technical parameters to assist the Customer to ensure that the design of the Customer's equipment connected to the transmission system shall coordinate with the transmission system to achieve compliance with the Code and this Agreement.

Replace by:

The minimum general performance standards for all equipment connected to the transmission system are set out in Appendix 2 of the Code. The Transmitter shall provide the technical parameters to assist the Customer to ensure that the design of the Customer's equipment connected to the transmission system shall coordinate with the transmission system to achieve compliance with the Code and this Agreement. Responsibility for costs of any upgrade of the Customer's equipment deemed compliant under section 2.6.2 of the Transmission Code will be determined by the OEB.

6 OPERATIONAL STANDARDS AND REPORTING PROTOCOL

6.2 The Transmitter shall specify the fault levels at all connection points, including the Customer's connection points, as required by the Market Rules, which shall be recorded in Schedule D to this Agreement.

Replace by:

The Transmitter shall specify the fault levels (and the assumptions behind those levels) at all connection points, including the Customer's connection points, as required by the Market Rules, which shall be recorded in Schedule D to this Agreement.

6.5 The Customer shall provide prompt notice to the Transmitter in accordance with the Code or as agreed in Schedule D to this Agreement before disconnecting its equipment from the transmission system.

Replace by:

Where practical, the Customer shall provide prompt notice to the Transmitter in accordance with the Code or as agreed in Schedule D to this Agreement before disconnecting its equipment from the transmission system.

7 Involuntary Disconnection

7.2.1.6 if the Customer is a defaulting Party; or

Replace by:

if the Customer is a defaulting Party, however when the issue of default has been disputed by the Customer, no disconnection of a Customer may occur without a final resolution of the dispute, pursuant to section 13 of this Agreement; or

7.3 Disconnection-General

7.3.2 The Customer shall pay all costs that are directly attributable to an involuntary disconnection, and decommissioning of its facilities, including the cost of removing any of the Transmitter's equipment from the Customer's property and shall cooperate in establishing appropriate procedures for such decommissioning.

Replace by:

The Customer shall pay all costs that are directly attributable to an involuntary disconnection, and decommissioning of its facilities, including the cost of removing any of the Transmitter's equipment from the Customer's property and shall cooperate in establishing appropriate procedures for such decommissioning. The Transmitter will not require the removal of the protection and control wiring within the generating facility.

7.4 Reconnection After Involuntary Disconnection

7.4.2.3 The Customer has taken all necessary steps to prevent circumstances causing the disconnection from recurring and has delivered binding undertakings to the Transmitter that the circumstances leading to disconnection shall not recur; and

Replace by:

the Customer has taken all necessary steps to prevent circumstances causing the disconnection from recurring, has delivered on the binding decision to the Transmitter and has satisfied all requirements on it arising from any arbitrator's decision pursuant to section 13.11 that the circumstances leading to disconnection shall not recur; and

9 REPRESENTATIONS AND WARRANTIES

9.1.1.3 that its facilities meet the technical requirements of the Code and this Agreement, excluding equipments that are deemed compliant under section 2.6 of the Code which is listed in Schedule J of this Agreement; and

Replace by:

9.1.1.3 that its facilities meet the technical requirements of the Code and this Agreement, excluding equipment that is deemed compliant under section 2.6 of the Code which is listed in Schedule J of this Agreement; and

10 REQUIREMENTS FOR OPERATIONS AND MAINTENANCE

10.4.1 Each Party shall specify its controlling authority in accordance with the operations schedule attached to this Agreement.

Replace by:

Each Party shall specify its Controlling Authority in accordance with the operations schedule attached to this Agreement.

10.4.2 The Transmitter and the Customer shall comply with all requests by the other Party's controlling authority in accordance with this Agreement and the Code.

Replace by:

The Transmitter and the Customer shall comply with all requests by the other Party's Controlling Authority in accordance with this Agreement and the Code.

10.6.2 When the Parties have so agreed in writing, one Party may appoint an employee of the other as its designate for switching-purposes.

Replace by:

When the Parties have so agreed in writing, one Party may appoint an employee of the other as its designate for switching-purposes. Orders to operate, however, must originate from the Controlling Authority.

10.7.3 The Transmitter shall provide to the Customer the isolation and reconnection of the Customer's equipment at the Customer's request at no cost to the Customer, once per year, during normal business hours. The Customer shall pay the Transmitter's reasonable costs for isolating and reconnecting the Customer's equipment if the requested isolation and reconnection is for a time outside of normal business hours.

Replace by:

The Transmitter shall provide to the Customer the isolation and reconnection of the Customer's equipment at the Customer's request at no cost to the Customer, one time per generating unit per year, which can be aggregated across multi-unit stations during normal business hours. The Customer shall pay the Transmitter's reasonable costs for isolating and reconnecting the Customer's equipment if the requested isolation and reconnection is for a time outside of normal business hours.

10.7.4 The Transmitter shall charge the Customer, and the Customer shall pay, the reasonable costs incurred by the Transmitter for isolating and reconnecting the Customer's equipment for any isolation and reconnection request in excess of one per year as specified in section 10.7.3 above.

Replace by:

The Transmitter shall charge the Customer, and the Customer shall pay, the reasonable costs incurred by the Transmitter for isolating and reconnecting the Customer's equipment for any isolation and reconnection request in excess of one time per generating unit per year, which can be aggregated across multi-unit stations as specified in section 10.7.3 above.

10.8.3 The Customer shall provide to the Transmitter the isolation and reconnection of the Transmitter's equipment at the Transmitter's request at no cost to the Transmitter, one time per generating unit per year, which can be aggregated across multi-unit stations, during normal business hours. The Transmitter shall pay the Customer's reasonable costs for isolating and reconnecting the Transmitter's equipment if the requested isolation and re-connection is for the time outside of normal business hours.

Include the above

10.8.4 The Customer shall charge the Transmitter, and the Transmitter shall pay, the reasonable cost incurred by the Customer for isolating and reconnecting the Transmitter's equipment for any isolation and reconnection request in excess of one time per generating unit per year, which can be aggregated across multi-unit stations as specified in section 10.8.3 above.

Include the above

10.13 **Emergency Operations**

Note that parts 10.13.3 to 10.13.8 do not apply to Generators.

Include the above

10.13.3 The Transmitter may be required from time to time to implement load shedding as outlined in this Agreement, Schedule D, section 7.

Exclude the above for Generators

10.13.4 The Customer shall identify the loads (and their controllable devices) to be included on the rotational load shedding schedules to achieve the required level of emergency preparedness.

Exclude the above for Generators

10.13.5 The Transmitter may review the rotational load-shedding schedule with the Customer annually or more often as required.

Exclude the above for Generators

10.13.6 The Customer shall comply with all requests by the Transmitter's controlling authority to shed load. Such requests shall be initiated to protect transmission system security and reliability in response to a request by the IMO.

Exclude the above for Generators

10.13.7 When the Transmitter's transmission facilities return to normal, the Transmitter's controlling authority shall notify the Customer's controlling authority to re-energize the Customer's facilities.

Exclude the above for Generators

10.13.8 The Transmitter may be required from time to time to interrupt supply to the Customer during an emergency to protect the stability, reliability, and integrity of its own facilities and equipment, or to maintain its equipment availability. The Transmitter shall advise the affected Customer as soon as possible/practical of the transmission system's emergency status and when to expect normal resumption and reconnection to the transmission system.

Exclude the above for Generators

15 COMPLIANCE, INSPECTION, TESTING AND MONITORING

15.1.5 When requested by the Transmitter, the Customer shall produce test certificates certifying that its facilities have passed the relevant tests and comply with all applicable Canadian standards before connection.

Replace by:

With respect to new, modified or replacement equipment to be connected to the transmission system, the Customer shall, when requested by the Transmitter, produce test certificates certifying that its facilities have passed the relevant tests and comply with all applicable Canadian standards before connection.

18 TECHNICAL REQUIREMENTS FOR TAPPED TRANSFORMER STATIONS SUPPLYING LOAD

The Transmitter, the Customer, who is either a Distributor or a Consumer, shall follow the technical requirements set out in Schedule H of this Agreement.

Replace by:

Not applicable to Generators

23 INCORPORATION OF SCHEDULES

Schedule "M" - Amendment Agreement Template

Include the above:

28 ENTIRE AGREEMENT

This Agreement, together with the schedules attached hereto, constitutes the entire agreement between the Parties and supersedes all prior oral or written representations and agreements of any kind whatsoever with respect to the matters dealt with herein.

Replace by:

This Agreement, together with the Addendum and schedules attached hereto, constitutes the entire agreement between the Parties and supersedes all prior oral or written representations and agreements of any kind whatsoever with respect to the matters dealt with herein.

<u>Amendments to Schedules “D”, “F”, “G”, “H”, and “I”</u>

Schedule “D”

Section 8 – Clause 1

1. A Customer shall re-verify its station protections and control systems that can impact on the Transmitter’s transmission system. The maximum verification or re-verification interval is: four (4) years for most of the 115 kV transmission system elements including transformer stations and transmission lines, and certain 230 kV transmission system elements; and two (2) years for all other high voltage elements. The maintenance cycle can be site specific.

Replace by:

A Customer shall re-verify its station protections and control systems that can impact on the Transmitter transmission system. The verifications will generally be carried out during generation outages. Where this cannot be accommodated within the time periods required for NPCC reporting, an entry will be made in the “EXCEPTIONS TO THE MAINTENANCE CRITERIA FOR BULK SYSTEM PROTECTION”. The target date for the completion of the program will be indicated.

Schedule “F”

1.6.2 A Transmitter may require a Customer to install monitoring equipment to track the performance of its facilities, identify possible protection system problems, and provide measurements of power quality. As required, the monitoring equipment shall perform one or several of the following functions:

Replace by:

A Transmitter may require request a Customer to install monitoring equipment to track the performance of its facilities, identify possible protection system problems, and provide measurements of power quality. The responsibility for costs will be as determined by the OEB. As required, the monitoring equipment shall perform one or several of the following functions:

1.6.5 The Customer shall bear all costs, without limitation, of providing all required telemetry data, associated with its facilities to the Transmitter and providing all required connection inputs to the Transmitter's disturbance-monitoring equipment.

Replace by:

The Customer shall bear all costs, without limitation, of providing the same telemetry data required under the Market Rules, associated with its facilities to the Transmitter and providing all required connection inputs to the Transmitter's disturbance-monitoring equipment, except:

- Where the connection inputs to the Transmitter's disturbance-monitoring equipment are of mutual benefit to the Customer and the Transmitter in which circumstance the Customer and Transmitter shall share the cost of providing the data in proportion to the benefits received; or

- Where the connection inputs to the Transmitter's disturbance-monitoring equipment are required only for the transmitter's benefit in which case the transmitter shall pay all of the costs associated with providing the data.

1.8.1 The Transmitter may at its sole discretion specify the maintenance criteria and the maximum time intervals between verification cycles for those parts of Customers' facilities that may materially adversely affect the transmission system. The obligations for maintenance and performance reverification shall be stipulated in the appropriate schedule to this Agreement.

Replace by:

The Transmitter, using Good Utility Practice, may specify the maintenance criteria and the maximum time intervals between verification cycles for those parts of Customers' facilities that may materially adversely affect the transmission system. The obligations for maintenance and performance re-verification shall be stipulated in the appropriate schedule to this Agreement.

1.8.5 To ensure that the Transmitter's representative can witness the relevant tests, the Customer shall submit the proposed test procedures and a test schedule to the Transmitter not less than ten business days before it proposes to carry out the test. Following receipt of the request, the Transmitter may delay for technical reasons the testing for as long as ten business days.

Replace by:

To ensure that the Transmitter's representative can witness the relevant tests, the Customer shall submit the proposed test procedures and a test schedule to the Transmitter not less than ten business days before it proposes to carry out the test. Following receipt of the request, the Transmitter may delay for technical reasons the testing for as long as ten business days. The Transmitter will use best efforts to make the required test date.

Schedule "G"

1.5 **Autoreclosure and Manual Energization**

1.5.2 Following a protection operation on a transmission line, the transmission breakers, located mainly in network switching and/or transformation stations, shall reclose after a certain time delay. The Generator shall provide a reliable means of disconnecting its equipment before this reclosure. The Generator is responsible for protecting its own equipment and the Transmitter is not liable for damage to the Generator's equipment. The Generator may request a means of supervising the transmission reclosure prior to the disconnection of its equipment e.g. changes in protection logic at one or both stations to reduce the risk of such events.

Replace by:

Following a protection operation on a transmission line, the transmission breakers, located mainly in network switching and/or transformation stations, shall autoreclose after a certain time delay. Where the Generator is directly connected to the transmission line, or for configurations where the Generator could be damaged by autoreclosure of the line, the Generator shall provide a reliable means of disconnecting its equipment before autoreclosure. The Generator is responsible for protecting its own equipment and the Transmitter is not liable for damage to the Generator's equipment except as stipulated in Section 8, Appendix 1 of this Code. The Generator may request a means of supervising the transmission autoreclosure prior to the disconnection of its equipment e.g. changes in protection logic at one or both stations to reduce the risk of such events. The criteria governing the use of reclosures are as set out in the Ontario Hydro "Policies, Principles, & Guidelines" document "C-3.4.1 (R1), Automatic Reclosure and Manual Eneregization on Bulk Electricity System Circuits," which was in effect as of April 1, 1999.

Schedule "H"

Technical Requirements for Tapped Transformer Stations Supplying Load:

(a) Transmitter's Tapped Transformer Stations

(b) Distributor's and Consumer's Tapped Transformer Stations

Exclude entire Schedule H

Schedule "I"

1.3.1 Customers shall perform routine verifications of protection systems on a scheduled basis as specified by the Transmitter in accordance with applicable reliability standards. The maximum verification interval is four years for most 115-kV elements, most transformer stations, and certain 230-kV elements and two years for all other high- voltage elements. All newly commissioned protection systems shall be verified within six months of the initial in-service date of the system.

Replace by:

Customers shall perform routine verifications of protection systems on a scheduled basis in accordance with applicable reliability standards. The maximum verification interval is four years for most 115-kV elements, most transformer stations, and certain 230-kV elements and two years for all other high-voltage elements. All newly commissioned protection systems shall be verified within six months of the initial in-service date of the system.

SCHEDULE 4
SPECIFIC NUCLEAR ARRANGEMENTS AND AREAS OF CLARIFICATION
Addendum Setting Out:

(i) The Obligations of the Transmitter in Respect of the Provision of Class IV Power and

(ii) the Rights and Obligations of the Parties in Respect of their Property Interests and Mutual Cooperation

Contents

I. Purpose

The purpose of this addendum is to capture those requirements that the Transmitter must meet and adhere to in order for the Customer to be in conformance with its Power Reactor Operating Licence (PROL) and fulfill its obligations to the general public in maintaining the nuclear safety of the generating units. Meeting these requirements necessitates changes, in whole or in part, to a number of the sections of the standard Connection Agreement attached to the Ontario Energy Board's Transmission System Code. These changes are documented below in a format that identifies the existing section in the Connection Agreement and sets out the section that replaces it.

The provision of a continuous and reliable supply of Class IV power is an integral part of maintaining and ensuring reactor safety. In shutdown or lay-up conditions, the unit service loads must continue to be supplied to ensure nuclear safety. Loss or degradation of the electrical grid can be one of the most safety-significant events to occur at nuclear power plants. Such events have the potential to result in loss of main heat sink forcing the transfer to back-up heat sink, loss of output, automatic safety system actuation, and degraded containment functions.

II. Principles Governing the Specific Nuclear Arrangements and Areas of Clarification

II.1 In any circumstance where there is an inconsistency between the terms of the Transmission System Code, the Connection Agreement and the terms of this Addendum, the terms of this Addendum shall prevail, except where contrary to applicable law.

II.2 Good Utility Practice is not intended to be limited to optimum practices, or methods, or act to the exclusion of all others, but rather to include all practices, methods or acts generally accepted in North America including those in the nuclear sector as the Customer holds a PROL from the Canadian Nuclear Safety Commission ("CNSC") and the Transmitter is providing a Transmission Service and Off-Site Power service to the Customer.

II.3 The Transmitter agrees to operate and maintain its transmission assets including the switchyards at the Customer's Facility in a manner which will meet the requirements of the Customer's PROL as reflected in this Addendum.

II.4 This Agreement shall continue in effect until a mutually agreeable termination date not to exceed the date on which the PROL for the Customer's Facility is terminated, provided that;

II.4.1 the Customer has satisfied all CNSC requirements and commitments required to be satisfied in order to eliminate the need for a transmission connection to provide an Off-Site Power service under this Agreement, and

II.4.2 the Customer no longer holds any other nuclear related licence for the Customer's Facility which identifies a requirement for an Off Site-Power service.

II.5 The Customer agrees to make timely application to the CNSC for authorization to terminate this Agreement when circumstances warrant.

II.6 Notwithstanding all other provisions of the Transmission System Code, the Connection Agreement and this Addendum except for Subsection 10.13.1 of the Connection Agreement, the Transmitter shall not, under any circumstances disconnect the Customer's Off-Site Power service required to meet its obligations under its PROL, either during the term of this Agreement, or upon its termination unless such action is pursuant to a decision of applicable regulator authority(ies) or a court having jurisdiction or the mutual agreement of the Customer and the Transmitter.

II.7 To the extent practicable, in the event of an Emergency as identified in Subsection 10.13.1 of the Connection Agreement that requires disconnection of the Customer's Facility from the Transmission System, or the Customer's Facility from the Off-Site Power services, the Transmitter shall give the Customer reasonable opportunity to shut down in a controlled manner such parts of the Customer's Facility as deemed appropriate by the Customer before the Transmitter disconnects the Customer's Facility from the Transmission System.

II.8 In the event of an unplanned outage of the conveyance of Off-Site Power, the Transmitter will use best efforts to promptly restore that service.

II.9 The Customer shall pay the additional incremental costs of the transmitter arising from any regulatory requirement from the CNSC coming into force after the execution of this Agreement;

II.9.1 Until such time as these costs can be recovered in rates or elsewhere and that the work giving rise to the costs has not been carried out for the benefit of other parties or as a requirement placed on the Transmitter from other sources; and

II.9.2 No additional costs are attributable to the provision of the Transmission connection in support of the conveyance of Off-Site Power at historical reliability levels.

II.10 Except as identified in the Connection Agreement Subsection 10.13.1 or applicable laws, the Transmitter shall take no action to prevent the Customer from utilizing the Off-Site Power.

III Specific Terms

The following provides changes, deletions and additions to specific clauses that form part of the amendments to the main Connection agreement Agreement and the Schedules thereto, as agreed to by the Parties.

<u>Amendments to the Connection Agreement</u>

<u>Incorporation of Procedures and Manuals by Reference</u>

Numbers appearing within square brackets “[ ]” incorporate by reference the procedures or manuals so designated in Schedule Q.

Include the above

1. DEFINITIONS

1.19 Abbreviations

ANO	Authorized Nuclear Operator
BES	Bulk Electricity System
GRMC	Generation Resource Management Center
NGS	Nuclear Generating Station
OATIS	Operating, Administrative and Trades Information System
OP&P'S	Operating Policies and Principles
OPEX	Operating Experience
P&SI	Process and System Implementation (Passport)
RTU	Remote Terminal Unit
SCR	Station Condition Record
SE	System Engineer
SLA	Service Level Agreement
SNO	Supervising Nuclear Operator
SPOC	Single Point of Contact

Include the above

1.20 "Class IV Power" has the meaning ascribed thereto in part I of this Addendum B;

Include the above

1.21 “CNSC” means the Canadian Nuclear Safety Commission, or its successor;

Include the above

1.22 “Corrective Maintenance” Consists of actions that restore, by repair, overhaul, or replacement, the capability of a failed system, structure, or component to perform its design function within acceptable criteria;

Include the above

1.23 “Customer Facility” means the facilities defined in Schedule A of this Agreement;

Include the above

1.24 “Design Authority” means the organization within each Party which has the authority to make final binding decisions and give approval regarding design requirements, design assurance, and design output for existing, new, and modified facilities, structures, systems, Equipment, and components, including material and software;

Include the above

1.25 “Equipment Ownership” means that authority which has design authority, maintenance responsibility and replacement responsibility for any particular piece of Equipment;

Include the above

1.26 “Good Utility Practice” means any of the practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good utility practice is not intended to be limited to optimum practices, or methods, or act to the exclusion of all others, but rather to include all practices, methods or acts generally accepted in North America.

As it relates to nuclear safety, Good Utility Practice also includes those practices, methods or acts generally accepted in North America relating to the conveyance of Off-Site Power as the

Customer holds a PROL from the CNSC and the Transmitter is providing Transmission Service and conveying Off-Site Power service to the Customer;

Include the above

1.27 “Modification” means any permanent or temporary addition, deletion or change to existing Equipment, systems or documentation;

Include the above

1.28 “Off-Site Power” means the electricity delivered conveyed by the Transmitter to the Customer’s Facility, generally through the Customer’s system service transformers, which enables the Customer to meet its obligations under its Power Reactor Operating LicenseLicence for the provision of a reliable supply of Class IV Power;

Include the above

1.29 “Open/Close Control” means an activity, authorized by the Controlling Authority, to change the position of a specific apparatus or device;

Include the above

1.30 “Part Substitution” means the installation of an item, which is not identical to the original item, and which does not alter the equipment or component design specifications of both the item and the applicable interfaces;

Include the above

1.31 “PASSPORT” means a suite of applications integrated into a central database capable of providing the required information infrastructure to enable business information to be shared in a (real-time) timely manner;

Include the above

1.32 “Power Reactor Operating Licence” or “PROL” means the licencse issued to the Customer pursuant to the Atomic Energy Control Act or its successor, the Nuclear Safety Control Act, for the operation of a nuclear installation in Canada;

Include the above

1.33 “Predefines” means identified work of a recurrent nature;

Include the above

1.34 “Predictive Maintenance” consists of the actions necessary to monitor, find trends, and analyze parameter, property, and performance characteristics or signatures associated with a piece of Equipment that indicate the Equipment may be approaching a state in which it may no longer be capable of performing its intended function;

Include the above

1.35 “Preventive Maintenance” consists of all those systematically planned and scheduled actions, including predictive or planned maintenance, performed for the purpose of preventing Equipment failure;

Include the above

1.36 Protected Area” means the area enclosed by station security fences with the entry and exit points controlled by the Customer’s security personnel. Personnel entering the protected area must have Security Clearance [11] or be sponsored and escorted by a Customer site employee who has Security Clearance;

Include the above

1.37 “Scheduled Outage” means a planned removal from service of Equipment that has been coordinated in advance with a mutually agreed start date and duration and is required for the purposes of inspection, testing, Preventive Maintenance or Corrective Maintenance;

Include the above

1.38 “Single Point of Contact” or “SPOC” means the individuals designated in Schedule D with overall work approving authority for a given facility whose function is (i) immediate review of identified needs for approval, (ii) verification of incoming needs for duplication, completeness, and validity, (iii) prioritization of work into major categories, (iv) recognition of potential system impairments, (v) encouragement of effective use of resources across the facility and approval of work-needs in accordance with the approved divisional work programs, (vi) to act as a representative of the facility and be an integral part of the work control, or (vii) participation in the final decision for resolution of issues [4];

Include the above

1.39 "Terminal Point" means a device that serves as a division point between Equipment under the control of any two authorities. Operation of a Terminal Point requires the approval of both Controlling Authorities;

Include the above

2. PURPOSE OF AGREEMENT

This Agreement sets out the terms and conditions upon which the Transmitter has agreed to offer, and the Customer has agreed to accept Connection Service.

Replace by:

This Agreement sets out the terms and conditions upon which the Transmitter has agreed to offer, and the Customer has agreed to accept connection service.

The Power Reactor Operating Licence held by the Customer requires that the switchyards at Customer's Facility meet a certain standard of reliability as a whole and at the level of the individual components. It also requires that switchyard operating procedures and maintenance practices meet certain prescribed standards. The Transmitter agrees to operate and maintain its transmission assets including the switchyards at the Customer's Facility in a manner which will meet the requirements of the Customer's PROL as reflected in this Agreement.

3. TRANSMISSION SYSTEM CODE

The Transmission System Code (the "Code") and this Agreement establish minimum testing, operational and maintenance standards for the Transmitter and the Customer. The Parties hereto hereby agree to be bound by, and to act at all times in accordance with the Code which is hereby incorporated in its entirety by reference into, and which hereby forms part of this Agreement.

Replace by:

The Transmission System Code (the "Code") and this Agreement establish minimum testing, operational and maintenance standards for the Transmitter and the Customer. The Parties hereto hereby agree to be bound by, and to act at all times in accordance with the Code which is hereby incorporated in its entirety by reference into, and which hereby forms part of this Agreement except insofar as it is inconsistent with the terms of this Agreement. In any circumstance where there is an inconsistency between the terms of the Code and requirements of the Customer's PROL, the requirements of the PROL shall prevail.

5. EQUIPMENT STANDARDS

5.3 The Transmitter and the Customer shall fully cooperate to ensure that modelling data required by the Code and this Agreement for the planning, design and operations of connections are complete and accurate, and the Transmitter shall order required tests where there are grounds to question the validity of such data. This includes, but is not limited to, the Information in Appendix 1, Schedule E, Parts (A) to (E), where applicable.

Replace by:

5.3 The Transmitter and the Customer shall fully cooperate to ensure that modelling data required by the Code and this Agreement for the planning, design and operations of connections are complete and accurate, and the Transmitter shall order required tests where there are reasonable grounds to question the validity of such data. This includes, but is not limited to, the information in Appendix 1, Schedule E, Parts (A) to (E), where applicable. Any such tests must be conducted in a manner consistent with the Customer's obligations under its Power Reactor Operating Licence.

6. OPERATIONAL STANDARDS AND REPORTING PROTOCOL

6.8 Upon learning of any changes that can affect the reliability of the Customer's facilities, the Transmitter shall promptly submit a written report to the Customer describing any and all changes, including, without limitation, changes to the Transmitter's facilities, equipment, and associated protective relaying or protective relaying settings, or any other changes of any kind whatsoever that might affect the reliability of that Customer's facilities.

Replace by:

Upon learning of, or before implementing any changes that may affect the reliability of the Transmitter's facilities, and in particular, the reliability of the conveyance of the Customer's Off-Site Power and its ability to meet its obligations under its Power Reactor Operating Licence, the Transmitter shall promptly submit a written report to the Customer describing any and all such proposed changes, including, without limitation, proposed changes to the Transmitter's facilities, Equipment, and associated protective relaying or protective relaying settings, or any other changes of any kind whatsoever that might affect the reliability of that Customer's facilities. The

Customer shall have a period of time as set out in Schedule D to consider whether the proposed change would materially affect its ability to comply with its obligations under its Power Reactor Operating Licence. In the event that the Customer, acting reasonably, determines that the proposed change would materially affect its ability to meet its obligations under the Power Reactor Operating Licence, the Transmitter shall not proceed with the proposed change without obtaining prior written approval of the applicable regulatory authority(ies). Any incremental costs which do not provide a benefit to the Transmission System resulting from altering the proposed change so as not to materially affect the Customer's ability to comply with the its obligations under the PROL, shall be identified by the Transmitter and paid for by the Customer.

7.2 Involuntary Disconnection

7.2.1 The Transmitter may disconnect the Customer's facilities, at any connection point at any time throughout the term of this Agreement in any of the following circumstances:

Replace by:

7.2.1 Notwithstanding all other provisions of this Agreement except for Subsection 10.13.1, the Transmitter shall not, under any circumstances except where authorized by an appropriate regulatory authority or court of law, disconnect the Customer's Off-Site Power required to meet its obligations under its Power Reactor Operating License, either during the term of this Agreement, or upon its termination. However, in the event of an Emergency that requires disconnection of the Customer's Facility from the Transmitter's transmission system facilities, the Transmitter shall, to the extent that it is within its control, give the Customer reasonable opportunity to shut down the nuclear reactors in a controlled manner before the Transmitter disconnects the Customer's Facility from the transmission system. Subject to the above, other than Off-Site Power, the Transmitter may, by following the requirements of this Agreement, disconnect the Customer's Facilities to prevent the Customer's electricity output from entering the Transmitter's transmission facilities during the term of the Agreement in the following circumstances:

7.3 Disconnection – General

7.3.3 For the duration of the disconnection the Transmitter shall not be obliged to fulfill any agreement to convey electricity to or from the Customer's facilities.

Replace by:

7.3.3 For the duration of the disconnection, the Transmitter shall continue to provide the conveyence of Off-Site Power service to the Customer's Facilities.

8 LIABILITY

8.1 The Transmitter shall only be liable to the Customer and the Customer shall only be liable to the Transmitter for any damages which arise directly out of the willful misconduct or negligence:

8.1.1 of the Transmitter in providing Transmission Services to the Customer;

8.1.2 of the Customer during the period it is connected to the Transmitter's transmission facilities; or

8.1.3 of the Transmitter or Customer in meeting their respective obligations under this Agreement, the Transmission System Code, their licences and any other applicable law.

8.2 Despite section 8.1, above, neither the Transmitter nor the Customer shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise.

Replace by:

8 LIABILITY

8.1 Subject to sections 8.2A and 8.2B below, the Transmitter shall only be liable to the Customer, and the Customer shall only be liable to the Transmitter, and each Party shall indemnify the other, only for damages that arise directly out of the willful misconduct or negligence:

8.1.1 of the Transmitter in providing Transmission Services to the Customer;

8.1.2 of the Customer during the period that it is connected to the Transmitter's transmission facilities; or

8.1.3 of the Transmitter or Customer in meeting their respective obligations under this Agreement, the Transmission System Code, their licences and any other applicable law.

8.2A the Transmitter shall not be liable to the Customer for any damages or loss caused by the hazardous properties of nuclear material as defined under the Nuclear Liability Act, R.S.C. 1985, N-28, as amended. In the event that any such damages or loss occur wholly or partially as a result of an unlawful act or omission of an employee, agent, contractor or sub-contractor of the Transmitter, done with the intent to cause injury or damage, the Transmitter shall not be liable for any claims by the Customer's insurer, in accordance with the letter dated May 10, 2001, from the Customer's insurer appended to this Agreement as Schedule R.

8.2B Neither Party shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise.

10 REQUIREMENTS FOR OPERATIONS AND MAINTENANCE

10.1.1 When the Transmitter's staff, its contractors, or agents work at the Customer's facilities or site, the Customer's safety and environmental requirements shall be observed by such staff, contractors and agents.

Replace by:

10.1.1 When the Transmitter's staff, its contractors, or agents work at the Customer's Facilities or site, the Customer's safety and environmental requirements and obligations under its PROL shall be observed by such staff, contractors and agents, to the extent that those requirements and obligations have been communicated to the Transmitter.

The Customer shall provide appropriate site specific training, as required by the Customer, for staff, contractors and agents nominated by the Transmitter, to cover the work identified by the transmitter. The Transmitter's staff, its contractors and its agents will only be expected to be trained in and observe those requirements identified for the particular area in which they are to work and the nature of that work.

10.1.2 When the Transmitter can show the Customer, to the Customer's satisfaction, that the Transmitter's safety and environmental practices provide for an equivalent or better level of safety or environmental protection, the Customer shall give permission to work to the Transmitter's safety and environmental practices. As a minimum, all applicable statutes and regulations shall govern such work.

Exclude the above

10.3.1 Operations and maintenance shall be performed only by qualified persons.

Replace by:

Operations and maintenance shall be performed by the Customer's staff at the Transmitters site and by the Transmitter's staff at the Customer's site shall be performed only by qualified persons trained to understand the hazards involved at each site.

10.6.3 The Customer shall comply with all switching instructions issued by the Transmitter's Controlling Authority to maintain the security and reliability of the transmission system. The two Controlling Authorities shall agree to procedures prior to undertaking any switching-operations.

Replace by:

10.6.3 The Customer shall comply with all switching instructions issued by the Transmitter's Controlling Authority to maintain the security and reliability of the Transmission System unless this conflicts with public safety, life, property, or the environment, as applicable to a Nuclear Generating Station and as required by the Customer's PROL or with the terms of this Agreement. The two Controlling Authorities shall agree to procedures prior to undertaking any switching operations.

10.11 **Scheduling of Planned Work**

In order to maintain the provision conveyance of reliable Off-Site Power service, the parties will co-ordinate outage plans in accordance with Good Utility Practice and shall use their best efforts to schedule outages on mutually acceptable dates. To the extent practical, the Transmitter shall schedule any shutdown, withdrawal or testing of facilities to co-ordinate with the Customer's scheduled outages.

Include the above

10.11.2 The Customer shall, take all reasonable steps to ensure that its anticipated and planned outages for the upcoming year are submitted to the Transmitter by October 1st of each year.

Replace by:

The Customer shall, take all reasonable steps to ensure that its anticipated and planned outages for the upcoming year are submitted to the Transmitter by October 1st of each year.

Notice requirements for planned work are contained in this Addendum under Schedule D "Outage Planning".

10.11.3 At least four days in advance of planned work that requires feeder breaker to be opened or operated and at least ten days in advance of planned work that requires operations of multiple feeder breakers, station bus or a whole transformer station, the Customer's Controlling Authority shall fax requests to the appropriate Transmitter contact identified in the operations schedule of this Agreement.

Replace by:

10.11.3 At least four days in advance of planned work by the Transmitter that requires a Transmitter's feeder breaker to be opened or operated and at least ten days in advance of planned work by the Transmitter that requires operations of the Transmitter's multiple feeder breakers, Transmitter's station Bus or a Transmitter's whole transformer station, the Customer's Controlling Authority shall fax requests to the appropriate Transmitter contact identified in Part 1, ScheduleDof this Agreement.

10.11.4.1 any disconnection from the Transmitter's transmission facilities of less than 50 kV e.g. disconnection from a feeder breaker owned by the Transmitter or by the Customer,

Exclude the above

10.11.4.2 load changes greater than 5 MW, or

Exclude the above

10.11.5 The Transmitter's Controlling Authority shall notify the Customer's Controlling Authority at least four days in advance of any planned work that requires a feeder breaker to be opened or operated and at least ten days in advance of planned work that requires operations of multiple feeder breakers, station bus or a whole transformer station, that directly affects the Customer's facilities, by contacting the appropriate Customer contact identified in the operations schedule to this Agreement.

Replace by:

10.11.5 The Transmitter's Controlling Authority shall notify the Customer's Controlling Authority at least ten days in advance of planned work that requires operations of a station bus, that directly affects the Customer's facilities, by contacting the appropriate Customer contact identified in Part 1, Schedule D of this Agreement.

10.11.9 Details regarding outage planning particular to the Customer are in Schedule D, Part 1, Section 6.2 “Outage Planning”.

Include the above

10.11.10 In circumstances where the Customer reasonably believes that there is a material threat to its ability to comply with its PROL, the Customer may direct the Transmitter to undertake work on the Transmitter's facilities or Equipment. The Transmitter shall comply with this direction promptly provided that this work does not conflict with the Transmitter’s legislative, regulatory or safety requirements, as the case may be. To avoid indiscriminate use of this provision, the request must be made by a Customer’s senior staff (e.g. director level or above) to the Transmitter’s Director of Network Management Program Execution or delegate. The Transmitter’s Director shall immediately authorize the directed work and the work shall be completed on an expedited basis.

Incremental costs incurred by the Transmitter in complying with this direction shall initially be paid by the Customer upon receipt of a bill outlining in reasonable detail the amount and breakdown of the incremental costs, and may later be shared between the Transmitter and the Customer by mutual agreement. In no circumstances will the Customer be billed under this section for regularly scheduled maintenance that was not performed by the Transmitter. Where the Customer and the Transmitter can not agree on the sharing of these costs, the matter shall be resolved through the Dispute Resolution process set out in Section 13 of this Agreement.

Include the above

10.14 Access and Security of Facilities

10.14.9 In an Emergency, a site owner may, as far as reasonably necessary in the circumstances, have access to and interfere with the other Party’s facilities. The site owner shall use reasonable efforts not to cause loss or damage to the other Party’s facilities. If the site owner interferes with any of the facilities, it shall indemnify the other Party for reasonable costs and expenses incurred from any resulting loss or damage.

Replace by:

10.14.9 In an emergency the Customer may, as far as reasonably necessary in the circumstances, have access to and interfere with the Transmitter’s facilities. The Customer shall use reasonable efforts not to cause loss or damage to the Transmitter’s facilities. If the Customer interferes with any of the facilities, it shall indemnify the Transmitter for reasonable costs and expenses incurred from any resulting loss or damage.

10.14.10 Access to Equipment in the switchyard and switchyard security is the responsibility of both Parties subject to the Customer's obligation under its Power Reactor Operating Licence. Only authorized personnel are allowed unaccompanied access to the switchyard. Access codes and keys shall be registered with Customer site security which must be kept informed of gates left unlocked on a shift by shift basis, otherwise all gates must be closed and locked at all times.

Include the above

10.14.11 The Controlling Authorities shall be notified upon entry and exit of personnel from the switchyard. The Transmitter and Customer will comply with each others procedures for accessing the switchyards: specifically the Transmitter's OATIS instruction [56], and the Customer's operating manual [18].

Include the above

11 TERM AND TERMINATION OF CONNECTION AGREEMENTS

This Agreement shall continue in effect until a mutually agreeable termination date not to exceed the date on which the Customer's PROL for the Customer Facility is terminated, provided that;

- the Customer has satisfied all CNS Crequirements and commitments required to be satisfied in order to eliminate the need for a transmission connection to provide an Off-Site Power service under this Agreement, and
- the Customer no longer holds any other nuclear related licence for the Customer's Facility which identifies a requirement for an Off Site-Power service.

or until such time the parties execute an agreement which provides for the conveyance of Off-Site Power in a manner which satisfies any license that the Customer is required to hold by the CNSC or other regulatory body.

Include the above

11.2 **Termination by a Non-Defaulting Party**

11.2.1 A non-defaulting Party may terminate the Agreement at any time during the term or any renewal thereof by giving the other Party six months' prior written notice setting out the termination date.

Termination in the event of a default shall follow the procedures set out in section 12.4 of this Agreement.

Exclude the above

11.3 **Right to Disconnect**

11.3.1 If a non-defaulting Party gives notice to terminate the Agreement under section 12.2.1, the Transmitter shall disconnect the connection point on the termination date specified in that notice or on another date that the Parties have agreed upon in writing.

Exclude the above

11.4 **Right to Remove Assets**

11.4.1 When a non-defaulting Party has terminated the Agreement under section 11.2.1, the Transmitter may disconnect the connection point and shall be entitled to de-commission and remove any of its assets associated with the connection and the connection point.

Replace by:

11.4.1 The Transmitter may only disconnect the connection point after the nuclear units are decommissioned. During the decommissioning phase, the Parties may negotiate a new connection agreement (the "New Agreement") to provide for the conveyance of Off-Site Power in a manner which satisfies any license that the Customer is required to hold by the CNSC or other regulatory body. Upon execution of the New Agreement, the Transmitter shall be entitled to decommission and remove any of its assets associated with the connection point and which are not required under the terms of the New Agreement.

12 EVENTS OF DEFAULT AND TERMINATION

12.4.1 A non-defaulting Party may, without prejudice to other rights and remedies provided for in this Agreement with respect to an Event of Default, which has not been remedied within the periods set forth below, terminate this Agreement by written notice to the defaulting Party:

Replace by:

12.4.1 A Non-defaulting Party may, without prejudice to other rights and remedies provided for in this Agreement with respect to an Event of Default, which has not been remedied within the periods set forth below, terminate this Agreement, provided that such termination under no circumstances permits the Transmitter to cease the conveyence of the Customer's Off-Site Power service required to meet its obligations under its Power Reactor Operating Licence, unless the Transmitter has the approval of the appropriate regulatory authority(ies) or a court of competent jurisdiction, it being the intent of the Parties that if the Customer is the Defaulting Party, the Transmitter can terminate the Agreement only insofar as it relates to the Transmitter's obligations to accept and transmit electricity generated by the Customer to the Market, by written notice to the Defaulting Party:

12.5.1 Neither the Transmitter nor the Customer may terminate the Agreement except in accordance with the applicable provisions set out in the Code or this Agreement.

Replace by:

12.5.1 Neither the Transmitter nor the Customer may terminate the Agreement except in accordance with the applicable provisions set out in the Code and this Agreement.

12.5.2 If either a Transmitter or a Customer chooses to terminate this Agreement pursuant to its rights under section 12.4, then upon termination the Agreement will, subject to section 12.5.3, be of no further force and effect.

Replace by:

12.5.2 If either a Transmitter or a Customer chooses to terminate this Agreement pursuant to its rights under section 12.4, then upon termination the Agreement will, subject to Subsection 12.5.3 and Subsection 12.4.1, be of no further force and effect.

12.6.1 If the Transmitter is the non-defaulting Party, the default has not been remedied and the cure period has expired, it may, on providing a written notice ten business days in advance, disconnect the connection point where the default remains unremedied at the end of the ten business days notice period.

Replace by:

12.6.1 If the Transmitter is the Non-defaulting Party, the default has not been remedied and the Cure Period has expired, it may, subject to Subsection 12.4.1, on providing a written notice ten business days in advance, disconnect the connection point where the default remains unremedied at the end of the ten business days notice period.

13 DISPUTE RESOLUTION

13.1 Exclusivity

13.1.1 Except where this Agreement states otherwise, the dispute resolution procedures set forth in this Agreement shall apply to all disputes arising between the Customer and the Transmitter regarding the Agreement and the Code and shall be the only means for resolving any such disputes.

Replace by:

13.1.1 Except where this Agreement states otherwise, the dispute resolution procedures set forth in this Agreement shall apply to all disputes, other than those relating to nuclear safety, arising between the Customer and the Transmitter regarding the Agreement and the Code and shall be the only means for resolving any such disputes.

13.2 Duty to Negotiate

13.2.1 Any dispute between the Customer and the Transmitter over this Agreement shall first be referred to a designated representative chosen by the Customer and to a designated representative chosen by the Transmitter for resolution on an informal basis.

Replace by:

13.2.1 Any dispute, other than those relating to nuclear safety, between the Customer and the Transmitter over this Agreement shall first be referred to a designated representative chosen by the Customer and to a designated representative chosen by the Transmitter for resolution on an informal basis. Any dispute relating to nuclear safety may be referred to such designated representatives on an informal basis or to a court of competent jurisdiction as set out in Subsection 13.3.1 below.

13.2.2 Such designated representatives shall attempt in good faith to resolve the dispute within thirty days of the date when the dispute was referred to them, except that the Parties may extend such period upon which they agree in writing.

Replace by:

13.2.2 Such designated representatives shall attempt in good faith to resolve the dispute within thirty days of the date when the dispute was referred to them, except that the Parties may extend such period upon which they agree in writing. When a dispute relating to nuclear safety is referred to such designated representatives, the designated representatives shall attempt in good faith to resolve the dispute within 48 hours of the date the dispute was referred to them unless the Parties agree otherwise in writing.

13.3 Referral of Unresolved Disputes

13.3.1 If the designated representatives cannot resolve the dispute within the time period set out in subsection 13.2.2, either Party may submit the dispute to binding arbitration and resolution in accordance with the arbitration procedures set out below.

Replace by:

13.3.1 If the designated representatives cannot resolve the dispute within the time period set out in subsection 13.2.2, either Party may submit the dispute to binding arbitration and resolution in accordance with the arbitration procedures set out below. If the dispute relates to nuclear safety, either party may apply to a court of competent jurisdiction to seek specific performance or injunctive relief. The Parties hereby agree that disputes relating to nuclear safety may cause irreparable harm to a Party, the Parties and/or the public for which ordinary damages are not an adequate or appropriate remedy and therefore it is necessary and appropriate to submit such disputes to a court of competent jurisdiction in order to obtain an order for specific performance or injunctive relief to compel the other Party to perform its obligations under this Agreement.

15 COMPLIANCE, INSPECTION, TESTING AND MONITORING

15.1.7 The Transmitter has the right to specify by addendum to this Agreement, the types of changes that require prior approval of the Transmitter before the Customer implements such changes. Such changes, that require prior approval of the Transmitter, shall be set out in Schedule A of this Agreement, and shall be limited to those that can have material adverse effect(s) on the Transmitter’s transmission facilities or facilities of its other Customers.

Replace by:

15.1.7 The Parties have the right to specify by addendum to this Agreement, the types of changes that require prior approval of the Transmitter before the Customer implements such changes or that require prior approval of the Customer before the Transmitter implements such changes. Such changes, that require prior approval of the Transmitter, shall be set out in Schedule A of this Agreement, and shall be limited to those that can have material adverse effect(s) on the Transmitter's transmission facilities or facilities of its other Customers. Such changes that require prior approval of the Customer shall also be set out in Schedule A, and shall be limited to those that, subject to Sections 6.3 and 6.8, materially affect the ability of the Customer to meet its obligations under its PROL.

23 INCORPORATION OF SCHEDULES

Schedule N - Switchyard Equipment Affecting Nuclear Safety

Schedule O - Reliability Indices Used in Nuclear Safety Analysis

Schedule P - Drawings

Schedule Q - References

Schedule R - Letter from the Nuclear Insurance Association of Canada

Include the above

28 ENTIRE AGREEMENT

This Agreement, together with the schedules attached hereto, constitute the entire agreement between the Parties and supersedes all prior oral or written representations and agreements of any kind whatsoever with respect to the matters dealt with herein.

Replace by:

This Agreement, together with the Addenda and Schedules attached hereto, constitutes the entire agreement between the Parties and supersedes all prior oral or written representations and agreements of any kind whatsoever with respect to the matters dealt with herein.

29 AMENDMENTS

29.1.8 Schedule M – Amendment Agreement Template

29.1.9 Schedule N – Switchyard Equipment Affecting Nuclear safety

29.1.10 Schedule O - Reliability Indices Used in Nuclear Safety Analysis

29.1.11 Schedule P – Drawings

29.1.12 Schedule Q – References

29.1.13 Schedule R – Letter from the Nuclear Insurance Association of Canada

Include the above

29.3 The Parties to this Agreement agree to forthwith, upon receipt of notice from the Board, do all things and take all actions necessary to amend this Agreement as specified by the Board.

Replace by:

29.3 The Parties to this Agreement agree to forthwith, upon receipt of notice from the Board, provided that such direction does not materially affect the Customer's ability to meet its obligations under its Power Reactor Operating Licence, do all things and take all actions necessary to amend this Agreement as specified by the Board. If the direction from the Board is determined to materially affect the Customer's ability to meet its obligations under its Power Reactor Operating Licence, the parties agree to notify the Board and seek resolution.

Amendments to Schedules

There are also a number of amendments to the Schedules required to cater for the requirements at the nuclear stations.

Schedule C - Include the Following

Areas of Impact	Cure Period
Any Action that Impacts on a Party's Obligations under its Power Reactor Operating Licence	Promptly

Schedule F

1.2.3 With advance notice to the Customer, the Transmitter's personnel may lock the isolating disconnect switch in the open position:

Replace by:

1.2.3 Except during an Emergency as permitted by Subsection 10.3.1, the Transmitter shall not lock the isolating switch in the open position without the prior written agreement of the Customer. With the prior written agreement of the Customer the Transmitter may lock the isolating equipment switch in the open position in the following circumstances.

IESO LETTER OF DIRECTION - 2014

ONTARIO POWER AUTHORITY

120 Adelaide Street West
Suite 1600
Toronto, Ontario M5H 1T1

T 416-967-7474
F 416-967-1947
www.powerauthority.on.ca

October 1, 2014

Mr. Mike Penstone
Vice-President, Planning
Hydro One Inc.
483 Bay Street
Toronto, Ontario M5G 2P5

Scope and Timing for the Northwest Bulk Transmission Line Project

Dear Mike,

The Northwest Bulk Transmission Line Project is a priority project identified in the 2013 Long-Term Energy Plan (LTEP). The purpose of this project is to augment the capacity and maintain the reliability of electricity supply to the area of northwestern Ontario (the Northwest) located west of Thunder Bay to support forecast electricity demand growth.

In designating this project as a priority project, the 2013 LTEP also instructed that Hydro One "begin planning for a new Northwest Bulk Transmission line, west of Thunder Bay, with the project scope to be recommended by the Ontario Power Authority (OPA)." This letter provides the project scope.

The supply today

The "West of Thunder Bay" area, for the purposes of this project, is shown in Figure 1. The area is bounded to the south and west by the US and Manitoba borders, and extends north to include Kenora, Dryden and Sioux Lookout, and east as far as (but not including) the City of Thunder Bay. The transmission system serving this area comprises the 230 kV and 115 kV circuits and stations connecting the Thunder Bay area and stations located at or near the major centres of Atikokan, Dryden, Fort Frances and Kenora, as shown in Figure 1. Note that the electrical system located north of Dryden is not included in this system definition; however as it is supplied from the West of Thunder Bay system, its net requirement (i.e. demand net of local resources in the area north of Dryden) is included for planning purposes as a power transfer out of the West of Thunder Bay transmission system at the Dryden station. The West of Thunder

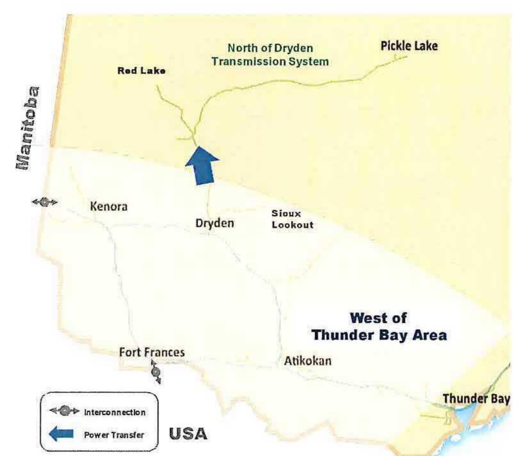


Figure 1: West of Thunder Bay Area

Bay transmission system is also interconnected with Manitoba at Kenora and Minnesota at Fort Frances.

The West of Thunder Bay area is generally self sufficient today. At present, peak electricity demand in the West of Thunder Bay area totals 210 MW in the winter and 145 MW in the summer. The West of Thunder Bay system also currently transfers up to 80 MW to the area north of Dryden (as described above). Local generation in the West of Thunder Bay area provides about 270 MW of dependable peak capacity – about 70 MW from run-of-river hydroelectric plants and 200 MW from the biomass-fueled unit at Atikokan GS. An additional 150 MW can be transferred to the West of Thunder Bay area through the transmission connection to Thunder Bay. The interconnections with Manitoba and Minnesota handle transfers scheduled on an economic basis and are not relied upon for supply adequacy at this time.

Potential Need for Increased Supply Capability

Both the West of Thunder Bay and North of Dryden areas have potential for economic development, in particular in the mining sector. The OPA's current demand forecast for the Northwest identifies a scenario of 160 MW of incremental load growth in the West of Thunder Bay area and about 75 MW in the North of Dryden area by 2025. Demand growth in the Northwest is highly dependent on mining sector related developments, and therefore carries uncertainty associated with timing, location and size of these developments. It is possible that demand could remain at today's levels, or could grow up to 30% higher than the current forecast. Due to the nature of the loads in the Northwest, demand growth can develop quickly and in large blocks, and planning for the area must take this possibility into account.

In consideration of the potential for significant but uncertain growth in the West of Thunder Bay and North of Dryden areas, the OPA updated its assessment of the capacity remaining on the existing West of Thunder Bay transmission system to serve demand growth in these areas. This assessment was conducted based on the latest demand and resource information, and is consistent with the IESO's ORTAC planning criteria.

The OPA's review identified, for planning purposes, two areas of adequacy concerns with the existing West of Thunder Bay transmission system. They are:

- There is 50-100 MW of additional capacity remaining that can reliably supply new loads in the North of Dryden area. Based on the current demand forecast, this capacity would be exceeded near the end of the decade.

- The power transfer capability from the Thunder Bay area (i.e. the two 230 kV transmission circuits from the Lakehead station to the MacKenzie station) is adequate today, assuming the generation at Atikokan is available. Currently, there is approximately 150 MW of margin remaining to serve new loads in the West of Thunder Bay and North of Dryden areas. However, if demand growth in the West of Thunder Bay and North of Dryden areas is in the range of the current forecast, the transfer requirement on this path will exceed these circuits' capability. If the Atikokan generation is not available, either because of biomass fuel limitations or contract termination (in 2024), the shortfall will be accentuated.

Options for Augmenting the Supply Capability

Both transmission and generation options are viable options for augmenting the supply capability in the West of Thunder Bay area and addressing the adequacy concerns cited above. Due to the long lead time required for new transmission line projects, it is typical to initiate development work in order to better scope the transmission option, and to shorten the subsequent lead time required if the project is selected.

Scope and Timing

The Northwest Bulk Transmission Line Project, in conjunction with the existing transmission system, must be capable of increasing the total westbound transfer from the Thunder Bay area from about 150 MW to 550 MW. In addition, the total transfer capability to the Dryden transformer station (TS) would need to be increased from about 170 MW to 300 MW, as shown in Figure 2.

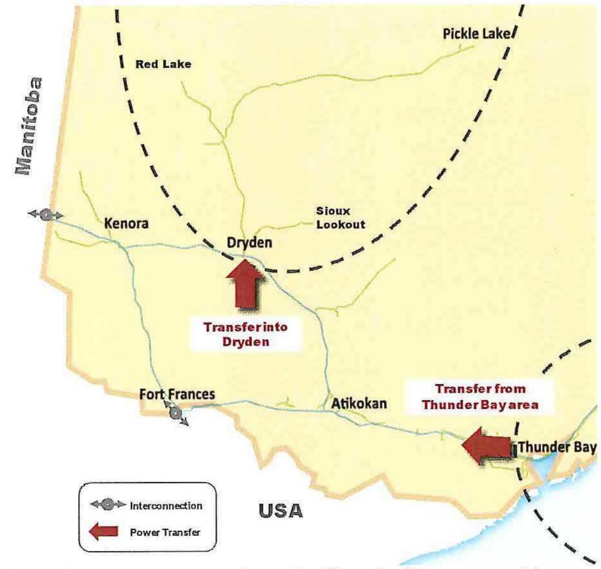


Figure 2: Power transfers from the Thunder Bay area and into the Dryden area

If demand grows as in the current forecast, the required in-service date for the Northwest Bulk Transmission Line Project could be as early as 2020.

The OPA has examined a number of configurations for the Northwest Bulk Transmission Line Project, including the option of 'twinning" the existing double-circuit 230 kV line between Lakehead TS and MacKenzie TS and the single-circuit 230 kV line from MacKenzie TS to Dryden TS. Hydro One should also consider other circuit configurations and routing options as appropriate. In all cases, only single-circuit or double-circuit 230 kV lines are to be considered. As requirements for switching and reactive facilities would depend on the configuration and line options, they are not specified at this time. Finally, consideration should be given to routing the section of the new line passing through the City of Thunder Bay such that it could facilitate future reinforcements of the electricity supply to the southern part of that city.

The scope of development work is to include preliminary design/engineering, cost estimation, public engagement/consultation, routing and siting, and Environmental Assessment preparation.

The OPA will provide support to Hydro One as required, including discussion of possible routing alternatives. As well, the OPA will continue to monitor developments in the region and confirm the best course of action to address the supply needs of the West of Thunder Bay area, and will keep Hydro One apprised of this work.

Sincerely,

Amir Shalaby
Vice-President, Power System Planning
Ontario Power Authority

cc
Bing Young
Ibrahim El-Nahas
Bob Chow
Joe Toneguzzo
Bernice Chan
Nicole Hopper
Nancy Marconi
Tabatha Bull
Luisa Da Rocha
Mark Wilson
Ahmed Maria
Ken Nakahara

IESO LETTER OF DIRECTION
PHASE 1 - 2018

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

October 24, 2018

Mr. Robert Reinmuller
Director, Transmission Planning
Hydro One Inc.
483 Bay Street, 13th Floor, North Tower
Toronto, Ontario M5G 2P5

Dear Robert,

Update on the Need and Scope for the Northwest Bulk Transmission Line

The Independent Electricity System Operator (the "IESO") recently updated its electrical load forecast and completed an assessment of the need for additional capacity to supply the West of Thunder Bay and North of Dryden areas (together, the "Region"), shown in Figure 1. The purpose of this letter is to describe the supply needs for the Region and the IESO's recommended next steps for meeting those needs.

Figure 1 – The Region

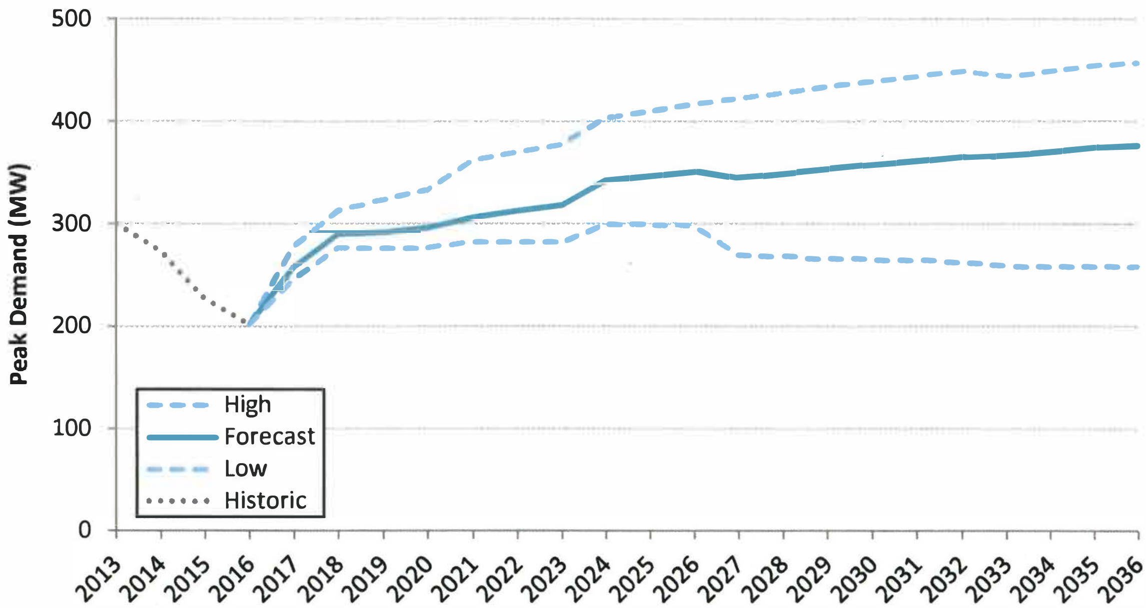
Supply Needs in the Region

Figure 2 below shows an updated electrical load forecast for the Region. The updated forecast considers new loads from potential mining developments, the connection of remote communities and the removal of loads from the cancelled Energy East pipeline conversion project.

Based on the forecast the Region is adequately supplied today; however, a need for additional capacity will arise in the mid-2030s.

The IESO's updated electrical load forecast also includes high and low growth scenarios to capture the uncertainty around industrial developments. Under the high growth scenario, which considers development of the Ring of Fire with electricity supplied by the Ontario transmission system, a capacity need could potentially arise in the early 2020s.

Figure 2 - Electrical Load Forecast – the Region



Addressing the Need

The Northwest Bulk Transmission Line Project (the "Project") was identified as a priority project in the 2017 Long-Term Energy Plan (the "LTEP") and can address the capacity needs described above. The LTEP divides the Project into three phases:

Phase 1 – a line from Thunder Bay to Atikokan;

Phase 2 – a line from Atikokan to Dryden; and

Phase 3 – a line from Dryden to the Manitoba border.

An Order in Council issued December 11, 2013 directed the Ontario Energy Board to amend the Hydro One Networks Inc. Electricity Transmission License to require Hydro One to develop and seek approvals for the Project in accordance with the scope and timing recommended by the IESO. The IESO's recommended scope and timing is outlined in the following paragraphs.

Scope and Timing

Since the capacity need is not likely to materialize until the mid-2030s, a commitment for additional supply to the Region is not required at this time. However, the IESO recognizes the risks associated with load forecast uncertainty and the potential for large industrial projects to add significant load to the Region utilizing the remaining capacity margin sooner than anticipated.

Therefore, to shorten the Project lead time if the need for additional capacity materializes earlier than expected, the IESO recommends that Hydro One begin development work on Phase 1 and Phase 2 of the Project as soon as possible. The scope of development work is to include preliminary design/engineering, cost estimation, public engagement/consultation, routing and siting, and Environmental Assessment. At this time the IESO is not committing to a timeline for the construction of the line. The IESO will continue to monitor developments in the Region to determine when construction of the transmission line should begin.

To supply the Region under the high growth scenario, the Project must meet the following specifications:

a) Consist of a new double circuit 230 kV line between Lakehead TS and Mackenzie TS (Phase 1) with a thermal capacity that is equal to or greater than the existing double-circuit 230 kV transmission between Lakehead TS and Mackenzie TS. This would achieve the required westbound transfer of at least 350 MW into Mackenzie TS and Moose Lake TS.

b) Consist of a new single circuit 230 kV line from Mackenzie TS to Dryden TS (Phase 2) with a thermal capacity that is equal to or greater than the existing single-circuit 230 kV transmission line between Mackenzie TS and Dryden TS. This would achieve the required westbound transfer of at least 350 MW from MacKenzie and Moose Lake.

c) Separate the necessary sections of F25A and D26A to ensure the circuits do not share a common structure over a distance that exceeds one mile.

Hydro One should consider various routing options as appropriate. Since requirements for switching and reactive facilities would depend on the configuration and line options, they are not specified at this time.

The 2014 letter from the Ontario Power Authority (the "OPA") to Hydro One indicated that the Project must be capable of 550 MW transfer west from the Thunder Bay area. At the time the letter was written, the OPA's electrical load forecast was significantly higher and included potential mining developments and the Energy East pipeline conversion project. If in the future additional transfer capability beyond 350 MW is needed, the solution would be to install dynamic reactive facilities in addition to the transmission lines indicated above.

The IESO will provide support to Hydro One as required, including discussion of possible routing alternatives. As well, the IESO will continue to monitor developments in the Region and confirm the best course of action to address supply needs, and will keep Hydro One apprised of this work.

Sincerely,

Ahmed Maria
Director - Transmission Planning
Independent Electricity System Operator

cc: Ms. Darlene Bradley, Hydro One
Mr. Leonard Kula, IESO
Mr. Terry Young, IESO
Mr. Alex Merrick, IESO

IESO LETTER OF DIRECTION
PHASE 1 – 2022

May 3, 2022

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

Mr. Robert Reinmuller
Director, Transmission Planning
Hydro One Inc.
483 Bay Street, 13th Floor, North Tower
Toronto, Ontario M5G 2P5

Dear Robert:

As per the Ontario Government's December 2013 Order in Council ("OIC") requiring Hydro One to develop and seek approvals for the Northwest Bulk Transmission Line (the "NWBL") according to the scope and timing recommended by the Independent Electricity System Operator ("IESO"), the IESO has updated its electrical demand forecast and the resulting needs for additional supply capacity in the area west of Thunder Bay (the "Region"). The purpose of this letter is to describe the updated supply capacity needs and the IESO's recommended high-level scope and timing for the construction of the line.

Background

The NWBL was identified in the Government's 2013 and 2017 Long Term Energy Plans (the "LTEPs") as a priority project in order to:

- increase electricity supply to the region west of Thunder Bay;
- provide a means for new customers and growing loads to be served with clean and renewable sources that comprise Ontario's supply mix; and,
- enhance the potential for development and connection of renewable energy facilities.

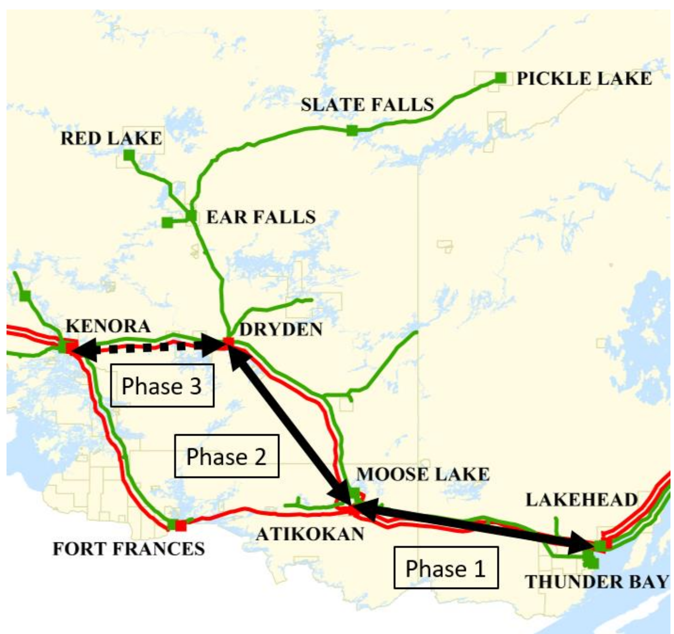


Figure 1 – West of Thunder Bay Area and NWBL Phases

The LTEPs divided the NWBL into three phases as shown in Figure 1:

- Phase 1 - a line from Thunder Bay to Atikokan;
- Phase 2 - a line from Atikokan to Dryden; and,
- Phase 3 - a line from Dryden to the Manitoba border through Kenora.

Following the 2013 LTEP, the Ontario Government issued an OIC, also in 2013, that amended Hydro One's license to develop and seek approval for the NWBL according to the scope and timing specified by the IESO.

In 2018, the IESO recommended that Hydro One commence development work (i.e., complete the Environmental Assessment) for Phase 1 and Phase 2 of the NWBL, between Thunder Bay and Atikokan, and Atikokan and Dryden, based on the timing of projected supply capacity needs and the risk of them materializing earlier. The IESO committed to ongoing monitoring to determine when construction of both Phase 1 and Phase 2 should begin and to confirm that they are the best course of action to meet the needs. Hydro One subsequently named Phase 1 and Phase 2 of the NWBL the Waasigan Transmission Line, hereafter called the "Project".

Scope and Timing for Construction

Since 2018, the IESO has updated the forecast in the Region and subsequently refreshed the supply capacity need dates. Figure 2 below shows the updated electrical demand forecast for the Region. Mining developments continue to be the main driver for growth. The demand forecast underpinning the latest update on the need for the Project includes mining growth assumptions informed by outreach and engagement with Indigenous and municipal communities and sector stakeholders as part of the ongoing Northwest Integrated Regional Resource Plan (IRRP). The update shows that under the reference demand forecast, Phase 1 is needed from 2025 onwards and Phase 2 is needed from 2026 to 2027 and uncertain thereafter. Although the need for Phase 2 is intermittent, the IESO recognizes the risks associated with demand forecast uncertainty and the potential for large industrial projects to add significant load to the Region utilizing the remaining capacity margin sooner than anticipated.

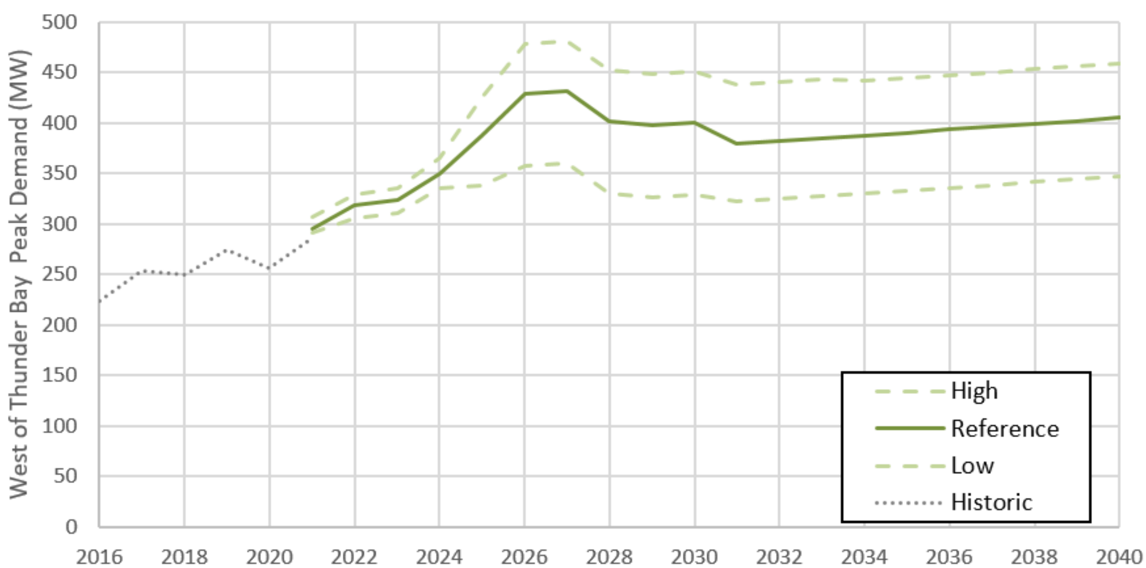


Figure 2 – West of Thunder Bay Electrical Demand Forecast

Given the timing of the needs, the range of possible growth scenarios, and the lead time for implementing solutions, the IESO recommends a staged approach for construction of the Project. Hydro One should construct the Project to meet near-term system capacity needs with Phase 1 being placed in-service as close to the end of 2025 as possible. Phase 1 continues to be the most cost effective option to meet the Region's supply capacity needs. The IESO will continue to monitor developments in the Region and provide the targeted in-service date for Phase 2; the IESO will provided an update on the timing of the need for Phase 2 at the beginning of Q2 2023, recognizing the Project lead-time. Hydro One will be required to manage the reasonable execution timing and staging of the Project for alignment with the in-service dates indicated by the IESO.

The IESO will provide support to Hydro One in obtaining Environmental Assessment and Ontario Energy Board approvals for the Project, as required.

Sincerely,

Ahmed Maria
Director, Transmission Planning
Independent Electricity System Operator

cc: Mr. Chuck Farmer, IESO
Mr. Devon Huber, IESO

IESO LETTER OF DIRECTION
PHASE 2 - 2023

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

April 24, 2023

Mr. Robert Reinmuller
Senior Director, Transmission Planning
Hydro One Inc.
483 Bay Street, 13th Floor, North Tower
Toronto, Ontario M5G 2P5

Dear Robert,

This letter is to provide updated recommendations related to the scope and timing of the Northwest Bulk Transmission Line (the "NWBL"), which is now referred to as the Waasigan Transmission Line. In the IESO's most recent communication of May 3, 2022, the IESO recommended that Phase 1 be constructed with an in service date as close to the end of 2025 as possible. At the time, a more detailed examination of the demand forecast was required to determine the timing of the need for Phase 2. The IESO committed to continuing to monitor developments in the area west of Thunder Bay ("the Region") and providing an update on the targeted timing of the need for Phase 2 in Q2 of this year. This letter describes the updated supply needs for the Region and the IESO's recommendation on Phase 2 timing to meet those needs.

Background

The NWBL was identified in the Government's 2013 and 2017 Long Term Energy Plans (the "LTEPs") as a priority project in order to:

- increase electricity supply to the Region;
- provide a means for new customers and growing loads to be served with clean and renewable sources that comprise Ontario's supply mix; and,
- enhance the potential for development and connection of renewable energy facilities.

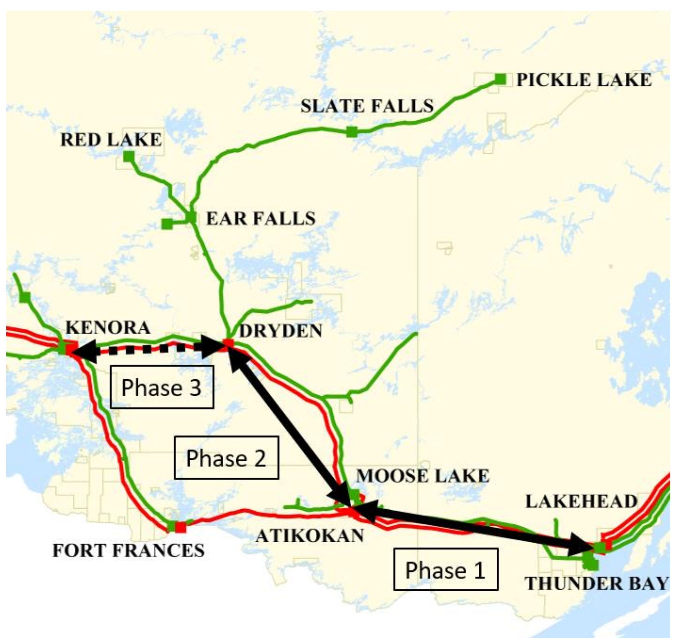


Figure 1 – West of Thunder Bay Area and NWBL Phases

The LTEPs divided the NWBL into three phases as shown conceptually in Figure 1:

- Phase 1 - a line from Thunder Bay to Atikokan;
- Phase 2 - a line from Atikokan to Dryden; and,
- Phase 3 - a line from Dryden to the Manitoba border through Kenora.

Following the 2013 LTEP, the Ontario Government issued an Order in Council ("OIC"), also in 2013, that amended Hydro One's license to develop and seek approval for the NWBL according to the scope and timing specified by the IESO.

In 2018, the IESO recommended that Hydro One commence development work, but not construction work, (i.e., complete the Environmental Assessment) for Phase 1 and Phase 2 of the NWBL, between Thunder Bay and Atikokan, and Atikokan and Dryden, based on the timing of projected supply capacity needs and the risk that they could materialize earlier than forecasted. Hydro One subsequently named Phase 1 and Phase 2 of the NWBL the Waasigan Transmission Line, hereafter called the "Project".

In 2022, construction of Phase 1 was recommended to proceed with an in-service date as close to the end of 2025 as possible. At that time, a more detailed examination of the demand forecast was required to determine the timing of need for Phase 2 of the Project.

Scope and Timing

The IESO has now completed its assessment of the need for Phase 2, based on a refreshed demand forecast supplemented by information provided by a third-party mining consultant, updated costs, and an analysis of non-wires alternatives.

Figure 2 below shows the updated peak electricity demand forecast for the area west of Atikokan (the area that would be supplied by Phase 2 of the Project) under four potential demand scenarios.

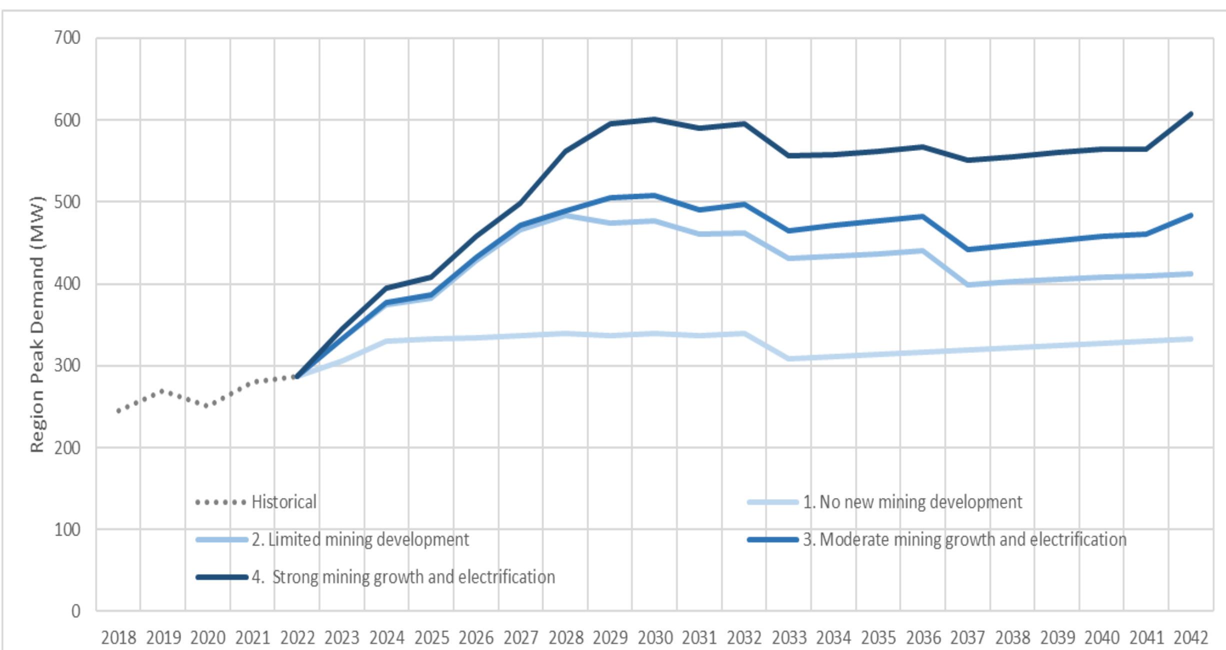


Figure 2 – Peak Electricity Demand Forecast for the Area West of Atikokan

Based on the updated demand forecast, there is a need for additional capacity under a range of growth scenarios beginning in 2025. Since, Phase 2 is needed in the same year as Phase 1, the IESO recommends that construction be staged to prioritize Phase 1 coming in service as close to the end of 2025 as possible (as previously recommended), with Phase 2 coming in service as soon as practical after Phase 1.

The scope of Phase 2, as described in previous communications, is a single-circuit 230 kV line from Mackenzie TS to Dryden TS. In order to ensure that transmission reinforcements planned today can be leveraged to meet a range of future needs and outcomes, the IESO also recommends that:

- Phase 2 be routed in proximity to Dinorwic Junction to facilitate potential future system reinforcements north of Dryden; and
- In designing the station layout for Dryden TS, space should be allocated for dynamic reactive support (i.e., a STATCOM or SVC) that may be required to support growth under higher demand scenarios.

The IESO will provide support to Hydro One as required in obtaining Environmental Assessment and Ontario Energy Board approvals for the Project.

Sincerely,

Ahmed Maria
Director, Transmission Planning
Independent Electricity System Operator

cc: Ms. Alessia Dawes, Hydro One Inc.
Mr. Spencer Gill, Hydro One Inc.
Mr. Chuck Farmer, IESO
Ms. Nicole Hopper, IESO
Mr. Devon Huber, IESO

IESO REPORT
WAASIGAN TRANSMISSION LINE PROJECT: NEED, ALTERNATIVES, AND RECOMMENDATION
JULY 26, 2023

Waasigan Transmission Line Project: Need, Alternatives, and Recommendation

July 26, 2023

ieso
Connecting Today.
Powering Tomorrow.

1. Introduction

The Independent Electricity System Operator ("IESO") is providing this report in accordance with the requirements of the Ontario Energy Board's ("OEB") Filing Requirements for Electricity Transmission Applications.[1]

This document sets out the broader context for planning in the west of Thunder Bay region ("the Region") in Northwest Ontario. It describes needs in the Region emerging as a result of anticipated demand growth under various demand forecast scenarios, discusses alternatives considered to meet the needs, and recommends the construction of the Waasigan Transmission Line Project to meet the Region's needs.

2. History and Summary of the Waasigan Transmission Line Project

The Waasigan Transmission Line Project was identified as a priority project in the Ontario government's 2013[2] and 2017[3] Long Term Energy Plans ("LTEPs"), then referred to as the "Northwest Bulk Transmission Line". In 2013, the government issued an Order in Council[4] directing Hydro One to develop the line, which Hydro One renamed the "Waasigan Project" (hereafter referred to as "the Project"). The 2013 LTEP also assigned responsibility for establishing the scope and timing of the Project to the Ontario Power Authority ("OPA"). This responsibility has since transferred to the IESO with the OPA/IESO merger in 2015.

The 2017 LTEP identified three conceptual phases to the Project, as shown in Figure 1 below. These phases have been further specified by the IESO and consist of:[5]

- Phase 1 — a new double-circuit 230 kV line from the Lakehead Transformer Station ("TS") in Thunder Bay to the Mackenzie TS in Atikokan.
- Phase 2 — a new single-circuit 230 kV line from the Mackenzie TS in Atikokan to the Dryden TS in Dryden.
- Phase 3 — a new line from Dryden to the Manitoba border through Kenora.

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[1] OEB Filing Requirements for Electricity for Electricity Transmission Applications, Chapter 4, March 16, 2023.

[2] https://www.ontario.ca/document/2013-long-term-energy-plan

[3] https://www.ontario.ca/document/2017-long-term-energy-plan

[4] https://www.ontario.ca/page/orders-council

[5] The Project also involves work at the Lakehead, Mackenzie and Dryden transformer stations to terminate the new lines, including the addition of static reactive support.

In 2018, the IESO recommended[6] that Hydro One commence development work on the first two phases, which comprise the proposed Project. The IESO has not identified a need for Phase 3 and is not recommending that it be developed at this time.

The Project's primary purpose is to supply forecast electricity demand growth in the Region, driven largely by new mining developments and extensions of existing mines. The associated increase in electricity demand is expected to exceed the capacity of the Region's existing transmission system in the near term, as further described in this report. The Project has been in the planning and development phases for several years and the IESO has recommended that its construction now move forward to satisfy future growth and enable economic development.[7]

Figure 1 | Waasigan Project Phases as per 2017 LTEP

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[6] https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/bulk/NW-Bulk-Transmission-Line-Scope-Letter-to-Hydro-One_24Oct2018.ashx

[7] https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/bulk/nwbl-20230424-letter-to-hydro-one-signed.ashx

3. Electricity System Needs in the Region

The IESO has identified bulk transmission system supply capacity needs arising in the near term in the Region. These supply capacity needs result from forecast electricity demand growth that is expected to exceed the capability of the Region's existing bulk electricity system in the near term. This section describes the Region, explains the IESO's demand forecast, which includes four scenarios, and compares the demand forecast scenarios against the capability of the Region's electricity system to identify the Region's capacity needs.

3.1 Description of the Region

The Region includes all the indigenous communities, municipalities, and industrial developments west of, but not including, the City of Thunder Bay. It is bounded to the south by the Minnesota border, to the west by the Manitoba border, and it extends northward to include the remote First Nation communities that will become grid connected through the Wataynikaneyap Transmission Project. This is a large and sparsely populated area, stretching approximately 450 km east to west, and 650 km north to south. It includes the towns of Atikokan, Fort Frances, Kenora, Dryden and Red Lake, as well as numerous smaller communities.

3.2 Demand Forecast

Electricity demand in the Region is winter peaking. It includes residential, commercial and small industrial demand supplied at distribution voltages as well as large industrial demand, primarily in the mining and forestry sectors, that receive supply directly from the transmission system.

The IESO's demand forecast for the Region consists of the following:

- distribution-connected electricity demand growth provided by LDCs.[8]
- electricity demand for the remote communities when they become connected to the grid.
- electricity demand for existing transmission-connected industrial customers.
- electricity demand for mining developments in the Region.

The bulk of the IESO's forecasted demand growth in the Region relates to mining development. Based on the prospect of higher carbon prices, and an increasing number of companies setting "net zero" targets, the IESO is aware that mining companies in the Region are taking steps to electrify their existing operations and may no longer see self-supply through onsite fossil fuel generation as a viable alternative to grid connection. When new mining projects proceed, they tend to develop on a relatively short timeline (2-3 years) and can quickly add large blocks of electricity demand to the system. As described in this report, the remaining capacity on the Region's electricity system is already limited and the Region's electricity system could quickly become overloaded if any one of the

[8] The LDC forecasts were provided by the Region's LDCs (Hydro One Networks Inc., Thunder Bay Electricity Distribution Inc. and Atikokan Hydro Inc.) through the regional planning process that led to the January 2023 Northwest IRRP (defined below). Consistent with the IRRP, the LDC forecasts for this assessment were adjusted by the IESO to reflect extreme weather and the effects of provincial Conservation and Demand Management (CDM) programs. This amounts to roughly 20 MW of CDM for the Region.

larger proposed mining projects proceeds. This would compromise reliability and could deter or prevent economic development in the Region.

The IESO maintains a bottom-up mining forecast based on known proposals for new mining projects and extensions of existing mines. The mining forecast is project-based and built from the bottom up based on known mining exploration or known mining 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 project-based forecast and the likelihood factors.

The timing of any specific project is uncertain and is dependent on a variety of factors that are difficult to predict, including commodity prices, access to capital, and the economics of a project relative to a mining company's global portfolio of potential investments. To address this uncertainty, the IESO relies on input and advice from informed stakeholders to forecast future needs. The input and advice received by the IESO indicates that there is substantial interest in developing new mines in the Region. While the majority of the known proposed mining projects in the Region are gold mines, federal and provincial government policies to support the development of "critical minerals" may be driving new types of mining ventures in the Region. For example, the IESO is aware of recent lithium mine proposals in the Region.

The IESO's mining forecast provides a well-supported view of potential development in the near-to-medium term. Engagement on the mining forecast was performed during the 2023 Northwest Integrated Regional Resource Plan ("IRRP") regional planning process where the IESO solicited public feedback on the forecast. However, the mining forecast does not capture long-term mining activity. For this reason, the IESO recently engaged a consultant, Posterity Group, to supplement the mining forecast with additional information on mining electrification trends as well as future growth potential beyond the horizon captured by the IESO's project-based forecast. To supplement the IESO's bottom-up mining forecast, the IESO incorporated Posterity Group's assessment of the effects of mine electrification and longer-term mineral production in developing demand forecast scenarios for the Region. The consultant's report is further described in Appendix D and attached as Appendix F.

The IESO employed a scenario approach to study the Region's needs under different possible futures and to study the corresponding flexibility of the alternatives to meet these needs. These scenarios represent a variety of possible outcomes while acknowledging the inherent uncertainty in forecasting mining electricity demand, particularly over the longer term. Four scenarios were developed by the IESO:[9]

1. Business As Usual – This scenario represents a continuation of recent trends in mining activity in the Region, with existing mines continuing to operate until they reach their end of life, but no new mining development occurring. This scenario is not considered likely to occur.

[9] Posterity Group's report was used by the IESO to inform the Moderate and Strong Growth scenarios.

2. Limited Growth – This scenario builds on the Business As Usual case and represents a future where only the most well-developed known mining projects proceed to production, and no significant mining electrification or future mining activity develops.
3. Moderate Growth – This scenario builds on the Limited Growth case, assuming some additional mining activity proceeds. It also introduces a moderate amount of future electrification of mining activities as well as future mining development, beyond the horizon foreseen by the bottom-up forecast.
4. Strong Growth – This scenario represents the most optimistic outlook for mining growth. It includes all existing mines and known proposals, as well as an additional proposed non-mining industrial facility that the IESO is aware of. This scenario also assumes a higher uptake of mining electrification initiatives and a higher outlook for long-term future mining growth.

Table 1 below summarizes the specific assumptions associated with each of the mining forecast scenarios.

Table 1 | Assumptions Included in Mining Electricity Demand Forecast Scenarios

Scenario	Project/Proposal Based Assumptions	Electrification Assumptions	Long-Term Production Assumptions
Business As Usual	Existing mines and their known life extensions	None	None
Limited Growth	Existing mines and their known life extensions The most advanced/well developed mining projects	None	None
Moderate Growth	Existing mines and their known life extensions The most advanced/well developed mining projects Some additional mining proposals	20% of mines reach net zero by 2050 (amounts to a 13.3% increase in electricity usage by 2050)	35% increase in mining demand between 2021 and 2050, above and beyond known proposals
Strong Growth	All existing mines and their known life extensions All known future mining proposals New non-mining industrial load	40% of mines reach net zero by 2050 (amounts to a 26.6% increase in electricity usage by 2050)	67% increase in mining demand between 2021 and 2050, above and beyond known proposals

These mining electricity demand scenarios were combined with the forecasts of LDC and remote community demand to develop the peak demand forecasts shown in *Figure 2* below. The figure shows the summer coincident peak demand for each forecast scenario.[10] The last five years of historical summer peak demand in the Region is also shown on the graph. Under the Business as Usual scenario there is a modest increase in electricity demand, while the other scenarios indicate that demand in the Region could increase substantially, up to a doubling of Regional electricity demand in the Strong Growth scenario.

The range of needs resulting from each of the demand forecast scenarios are described in the next section.[11]

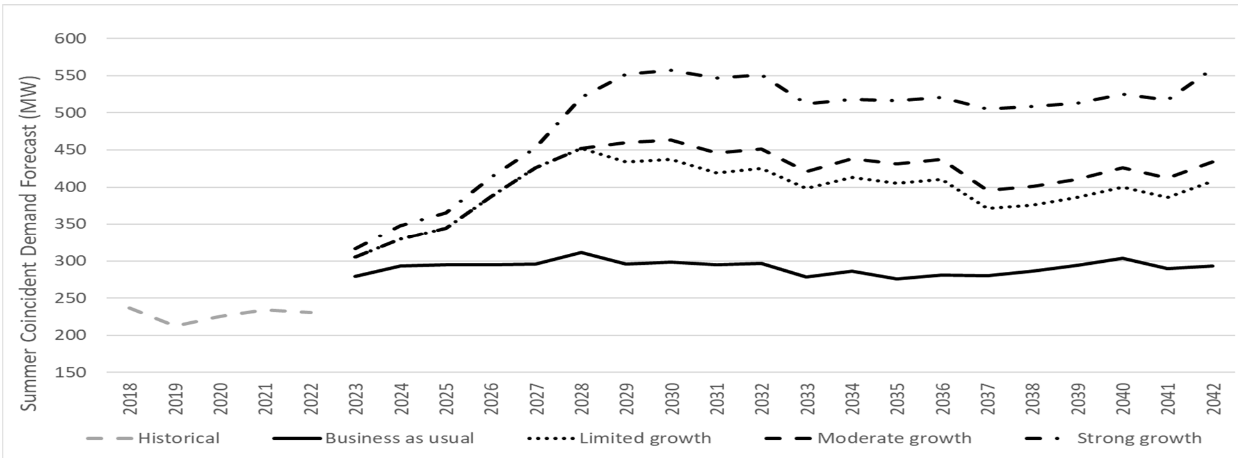

Figure 2 | Summer Peak Demand Forecast Scenarios for the West of Thunder Bay Region[12]

3.3 Capacity Needs

To assess the implications of this growth, it is necessary to understand the Region's electricity system. The next sections discuss the relevant limiting transmission interfaces within the Region, describe the capability of the existing system, and identify the timing and size of the Region's capacity needs.

3.3.1 The Region's Electricity System and Transmission Interfaces

Figure 3 below identifies the Region's key transmission lines, sub-systems, and interties with Manitoba and Minnesota. The proposed new lines that form the Project are also shown in the diagram using dotted lines.

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[10] While the Region is winter peaking, as will be described below, lower equipment thermal limits and local generation availability in the summer result in a greater need in the summer than in the winter.

[11] The extent of future demand growth (i.e., whether a specific Limited, Moderate, or Strong growth scenario materializes) is not relevant to the IESO's recommendation for the Project. As will be demonstrated, there is a need in all scenarios, and the Project satisfies the need and can be demonstrated to be the only feasible alternative in all growth scenarios.

[12] The historical data has not been weather corrected, whereas the LDC portion of the forecasted demand is corrected to reflect extreme weather as required by IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC). This is one reason why the forecasted demand appears higher than the historical demand trend. Outages to industrial customers may also be reflected in the historical demand.

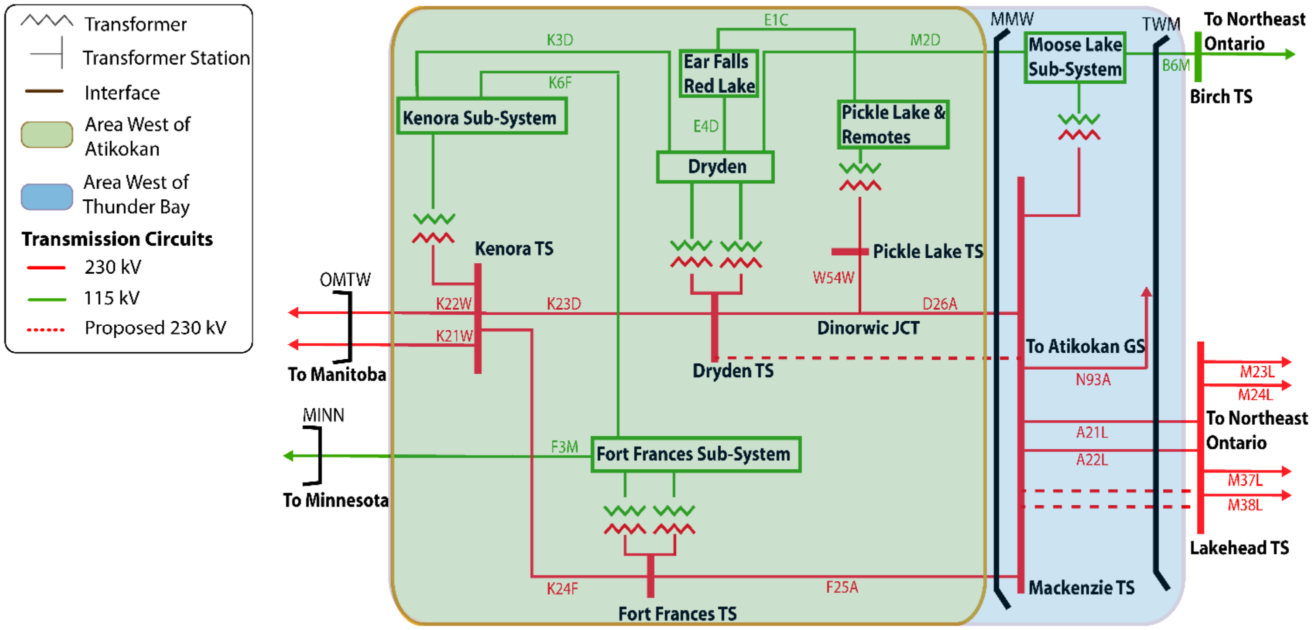

Figure 3 | West of Thunder Bay Transmission System

The bulk system that transmits power across the Region consists of a network of 230 kV lines. To the east, two 230 kV circuits sharing a common tower line connect Lakehead TS in Thunder Bay and Mackenzie TS in Atikokan. At Mackenzie TS, the system branches into two single-circuit 230 kV lines that run to Fort Frances and Dryden, and then converge at Kenora. Underlying this bulk system are 115 kV lines that parallel the bulk system and form sub-systems that supply demand and connect local generation.

Local generation in the Region consists primarily of run-of-river hydroelectric facilities and biomass generation. When available, a substantial portion of the Region's demand can be supplied from these resources. However, the Region is subject to periodic droughts, limiting hydroelectric generation capacity, and the biomass generation in the area is fuel-limited. The balance of the Region's supply needs is met by transfers across the transmission system. During periods of high electricity demand and/or low local generation output, power flows westbound into the Region from the Thunder Bay area and/or imports may be scheduled from Manitoba and/or Minnesota.[13]

3.3.2 Limiting Transmission Interfaces

The IESO conducted power systems studies to assess the ability of the Region's electricity system to supply the forecasted demand. These system studies were performed in accordance with applicable planning criteria, namely: the NERC TPL-001 "Transmission System Planning Performance Requirements" (TPL-001), NPCC Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System" (Directory #1), and IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC).

[13] Conversely, during periods of low electrical demand and/or high local generation output, excess power flows eastbound out of the Region or is exported through economic intertie transactions to Manitoba or Minnesota.

Based on the results of the system studies, the IESO has identified two transmission interfaces within the Region that are expected to be limiting in the near term if no system reinforcement is made:

- The "Transfer West into Mackenzie" (TWM) interface, defined as the flow west into Mackenzie TS on the 230kV circuits A21L and A22L plus flow west into Moose Lake TS on the 115kV circuit B6M. This interface transfers power into the Region from the rest of the Ontario system.
- The "Mackenzie Moose Lake Flow West" (MMW) interface, defined as the flow west from Mackenzie TS on the 230 kV circuits D26A and F25A plus flow west from Moose Lake TS on the 115 kV circuit M2D. This interface transfers power westward from Atikokan.

The TWM and MMW interfaces, their associated transmission circuits, and the areas they supply are shown inFigure 3 above. The TWM interface supplies the area west of, but not including, Thunder Bay. The MMW interface supplies the area west of, but not including, Atikokan; this is a subset of the area supplied by the TWM interface.

3.3.3 Timing and Duration of Need

The system studies established the "Load Meeting Capability" ("LMC") associated with the TWM and MMW interfaces based on existing electricity infrastructure. The LMC represents the amount of electricity demand that can be supplied by the system while meeting applicable planning criteria. The LMC is a function of both the dependable capacity of local generation in the area and the capability of the transmission system. For both interfaces, dependable local generation capacity is insufficient to supply the area's electricity demand and the balance is made up by transfers into the area on the respective TWM and MMW interfaces.

Both the TWM and MMW interfaces are limited by the thermal capability of their associated 115 kV circuits upon the loss of the respective parallel 230 kV system elements. Because equipment thermal ratings are lower in the summer, and the output of local hydroelectric generation is also lower in the summer, the IESO calculated separate summer and winter LMCs for each area (see Table 2 below).

Table 2 | Area LMCs in the Region

Area	**Associated Transmission Interface**	**Area Summer LMC (MW)[14]**	**Area Winter LMC (MW)[14]**
West of Thunder Bay	TWM	257	365
West of Atikokan	MMW	305	385

While the majority of the existing and forecast demand in the Region affects both interfaces, there are some loads that, due to their location between Thunder Bay and Atikokan, contribute to loading on the TWM interface but not the MMW interface (seeFigure 3).[15] Accordingly, the LMC for each

[14] 150 MW of load rejection as allowed by ORTAC criteria was assumed to be available as a post-contingency control action in the derivation of the LMCs for the existing system.

[15] Similarly, there is a small amount of local generation that contributes to the LMC associated with the TWM interface but not the MMW interface.

interface was compared to a corresponding area demand forecast to determine when each interface reaches its capability.

While the Region is winter peaking, due to the high proportion of industrial demand in the Region, the demand profile is relatively flat with limited seasonal variation. At the same time, for the reasons stated above, the LMCs are lower in the summer for both interfaces. As a result, while electricity demand is forecast to be higher in the winter, the need for supply capacity is greater and emerges sooner in summer than in winter for both areas.

Figure 4 below shows the summer LMC associated with the TWM interface, along with the summer peak demand forecast scenarios for the area west of Thunder Bay, which is supplied by this interface. Where a demand forecast line exceeds the LMC, there is a need for additional supply capacity under that forecast scenario.

Based on the historical demand (also shown in Figure 4) the TWM interface is already very close to capacity and even a small amount of demand growth would cause the LMC to be exceeded. Based on forecasted demand for this interface, all demand forecast scenarios (including Business as Usual) indicate a need in the near term. Moreover, as Figure 4 shows, in all scenarios except Business as Usual, the need continues to grow and peaks in the late 2020’s or early 2030’s. Table 3 below shows the size of the highest capacity need for each scenario and the year it is forecast to be reached. The highest capacity need is the largest gap between forecasted demand and LMC over the 20-year forecast time horizon.

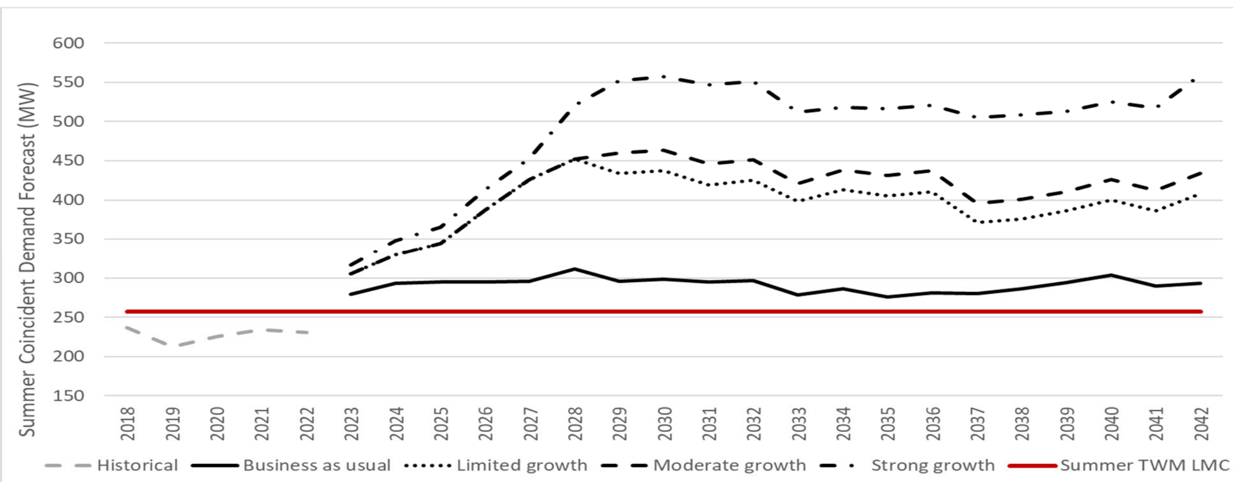

Figure 4 | Summer LMC and Demand Forecast Scenarios for the TWM Interface

The peaks from Figure 4 are described in Table 3 below.

Table 3 | Maximum TWM Summer Capacity Need by Scenario

Scenario	Highest Forecast Summer Peak Demand	Size of Highest Capacity Need[16]	Year of Highest Capacity Need
Business As Usual	311 MW	54 MW	2028
Limited Growth	447 MW	190 MW	2028
Moderate Growth	463 MW	206 MW	2030
Strong Growth	559 MW	302 MW	2042

Figure 5 below shows the summer LMC associated with the MMW interface along with the summer peak demand forecast scenarios for the subset of electricity demand (located west of Atikokan) that affects this interface. This area has a higher LMC than that supplied by the TWM interface and can accommodate a higher level of demand growth before its limit is reached. A need does not materialize for this interface before 2042 under the Business as Usual scenario. A need emerges in 2024 or 2025 under all forecast scenarios, except for Business as Usual, which is provided as reference and not as a likely future for the Region. Table 4 below shows the size of the highest capacity need for each scenario and the year it is forecast to be reached.

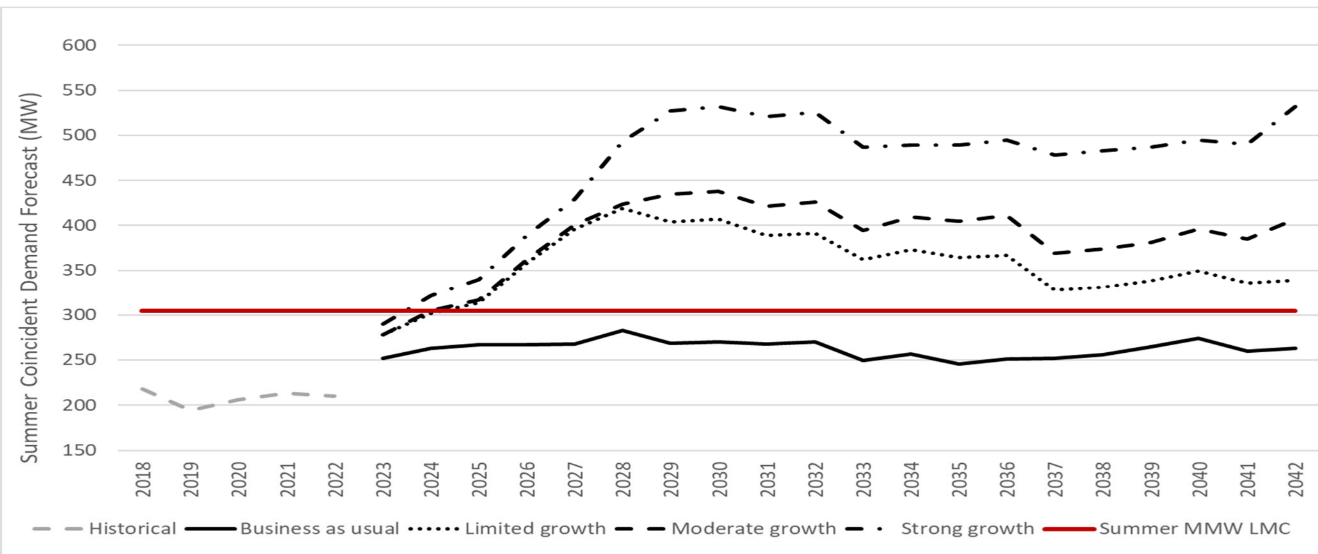

Figure 5 | Summer LMC and Demand Forecast Scenarios for the MMW Interface

The peaks from Figure 5 are described in Table 4 below.

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[16] 150 MW of load rejection as allowed by ORTAC criteria was assumed to be available as a post-contingency control action in the derivation of the LMCs for the existing system.

Table 4 | Maximum MMW Summer Capacity Need by Scenario

Scenario	Highest Forecast Summer Peak Demand	Size of Highest Capacity NeedError! Bookmark not defined.	Year of Highest Capacity Need
Business As Usual	283 MW	-	2028
Limited Growth	419 MW	114 MW	2028
Moderate Growth	438 MW	133 MW	2030
Strong Growth	532 MW	227 MW	2030/2042

While the summer peak demand defines the highest needs, capacity needs are prevalent throughout the year because demand in the Region is winter peaking and consists of a high proportion of relatively flat industrial demand. The needs based on the winter LMCs and winter peak demand forecasts on both interfaces are presented in Appendix A.

To illustrate the profile of the Region's capacity needs, Figure 6 below presents the hourly electricity demand forecast for the year 2030 for the Moderate Growth scenario in the Region and compares it to the TWM interface area's summer and winter LMCs. Based on this example, the need varies by season, but is present over all hours of the year. The long duration of the need is an important factor in the consideration of the alternatives discussed in the next section.

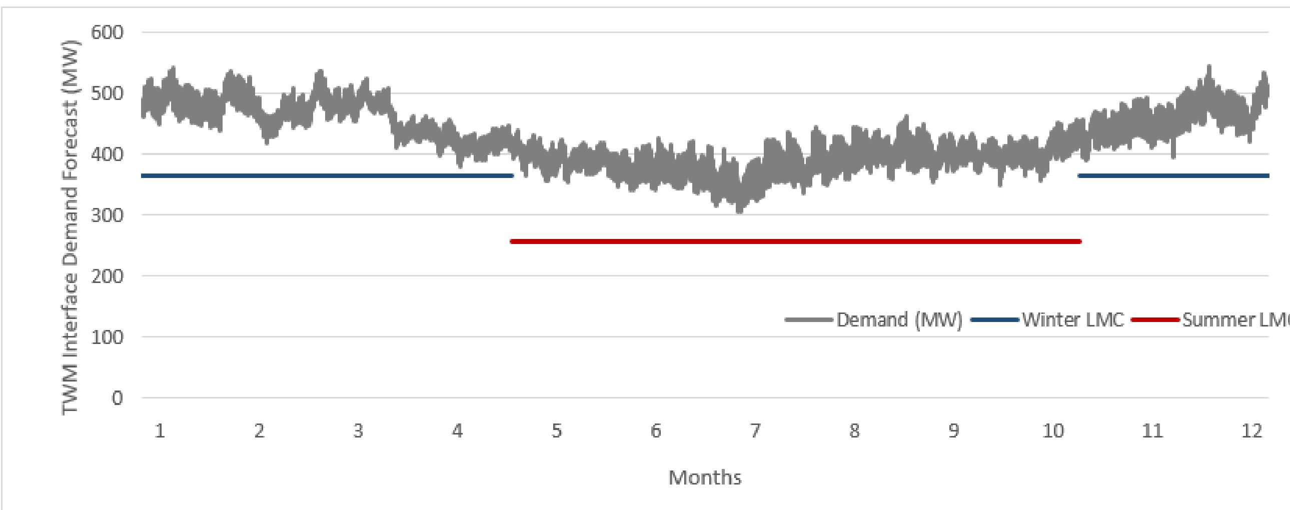

Figure 6 | West of Thunder Bay 2030 Moderate Growth Hourly Demand and Summer/Winter LMCs

4. Alternatives Considered

The IESO considered several alternatives to address the needs arising under each of the Region's demand forecast scenarios, including transmission reinforcement, incremental conservation and demand management (CDM), new non-emitting supply resources (including storage), and new gas-fired generation.

To assess the alternatives, the IESO first applied a screening test to determine whether the option could feasibly address the size and timing of the required need as identified by the IESO's forecast scenarios, and whether the alternative could be implemented. Alternatives that could not meet these requirements were screened out from further consideration. As detailed below, the transmission reinforcement was the only alternative deemed to be both feasible and implementable.

Even though the other alternatives were screened out, the IESO nonetheless performed an economic evaluation to assess the cost performance of the transmission alternative against a conceptual gas-fired generation alternative. Gas-fired generation was selected as a non-wires benchmark for this analysis based on its technical characteristics in relation to the characteristics of the need, and its competitive cost as compared to non-wires alternatives.

The alternatives considered, the IESO's assessment of their feasibility to meet the timing and size of the need, and implementation considerations are discussed below.

4.1 Transmission Reinforcement Alternative

The transmission reinforcement considered in this assessment is the proposed Project. The Project would address the identified needs in section 3.3 by reinforcing the TWM and MMW interfaces, expanding supply capability into the Region, and could be deployed to meet the timing of the need.[17]

Phase 1 of the Project would expand the TWM interface by adding two parallel 230 kV circuits, and Phase 2 would expand the MMW interface by adding one parallel 230 kV circuit (seeFigure 3). The Project would also involve work at the Lakehead, Mackenzie and Dryden transformer stations (seeFigure 3) to terminate the new lines and add static reactive support.

With the implementation of the Project, the Region would have enough capacity to supply demand growth up to and including the highest forecast summer peak demand under the Business As Usual, Limited Growth and Moderate Growth scenarios. If additional growth beyond the Moderate Growth forecast occurs, it is expected that dynamic reactive support in addition to the Project will be required. With the implementation of the Project and the addition of the dynamic reactive support, initial system studies indicate that the majority of the demand growth forecasted in the Strong

[17] Hydro One has already completed substantial development work for the Project, shortening the lead time to implement the transmission alternative. The scope of development work includes preliminary design/engineering, cost estimation, public engagement/consultation, routing and siting and the Environmental Assessment.

Growth scenario could be supplied.[18] If a Strong Growth scenario were to be realized, further system expansion would need to be explored that builds on the Project.

The number, size and location of dynamic reactive devices required—as well as the exact amount of load that can be supplied before they are needed – will depend on the amount and location of electricity demand growth. Based on recent similar projects, the IESO anticipates this additional infrastructure could cost between $100-150 million to deploy (i.e., in addition to the cost of the Project itself). The IESO will continue to monitor the timing and location of demand growth and, if necessary, will recommend the size and location(s) of the required reactive support accordingly.

As indicated in section 3.3, based on the historical demand the TWM interface is already very close to capacity. Based on forecasted demand for this interface, all demand forecast scenarios (including Business as Usual) indicate a need in the near term. The Project's Phase 1 is expected to be in-service by the end of 2025 and Phase 2 by the end of 2027. In the interim, the IESO will monitor the demand growth and take appropriate operational actions.

Overall, the Project improves system capability and is technically feasible of meeting the Region's supply capacity needs. The investment also creates the necessary foundation to support a scenario where the Region experiences higher than Moderate Growth.

4.2 Conservation and Demand Management (CDM)

The impact on electricity demand of the current 2021-2024 CDM Framework as well as assumed program renewals post-2024 amounts to approximately 20 MW. This was included in the LDC portion of the demand forecast (see section 3.2). The IESO's standard screening process for CDM was implemented to determine if targeted CDM incremental to that included in the demand forecast could be a feasible alternative to the Project. The screening process evaluated identified regional and bulk planning needs, stated in section 3.3, against a standard set of criteria, which are described further in Appendix C. These standard criteria are used as an initial assessment of the feasibility of employing incremental targeted CDM as a non-wires solution. CDM was screened out as an alternative largely due to size and timing of the need as further discussed in Appendix C. The forecasted pace of demand growth significantly outpaces the ability to acquire demand reduction through incremental CDM initiatives. As incremental CDM did not pass the initial screening process, the IESO did not further consider it as an alternative.

4.3 New Non-Emitting Supply Resources

The IESO investigated a variety of non-emitting resource options to address the need, however, they were screened out because they are not cost-effective when compared to the gas generation alternative, have longer development timelines and/or cannot meet the characteristics of the need as covered in Table 5 below.

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[18] Preliminary system studies suggest that the Project combined with additional reactive support could supply all but approximately 20-25 MW of the Strong Growth forecast. However, this result is dependant on the location and size of demand growth and further, more detailed study will be required to refine these results as these factors become known.

Table 5 | Screening of Non-Emitting Supply Resources

Resource	Rationale for Screening Out
New hydro-electric generation	Development of new hydroelectric generation cannot be built in time (typically 4 to 6 years, however, varies by site with the recent North Bala Small Hydro project taking 9 years to reach commercial operation) to address the need. No new hydroelectric projects large enough to meet the need are currently being studied or proposed in the Region.
Solar and Wind	Solar and wind production profiles do not meet the need requirement, which is relatively flat (i.e., with a constant energy requirement) throughout the year, whereas wind and solar output is intermittent. Details of the need is discussed in Section 3.3 and the need profile is illustrated in Figure 6.
Battery Energy Storage Systems ("BESS")	Demand requirements do not provide a sufficient number of hours to charge and dispatch. The need can exceed 40 hours consecutively in the winter season.
Hybrid Resources (BESS paired with non-emitting resources)	Hybrid resources are not a viable solution due to the large size of battery required (i.e. larger than the current long duration batteries commercially available exceeding 20 hours). Wind hybrids are also not a viable solution due to the magnitude of wind capacity that would be required. Solar hybrids are also not a viable solution due to the high electricity demand forecast in the winter and the low capacity factor of solar generation.
Small Modular Reactors ("SMRs")	Not commercially available until after 2029, as the pilot facility at Darlington will not commence operation until 2028. SMRs are costlier than the gas generation alternative included in the economic analysis below.
Hydrogen-fueled generation	Commercial-scale application of this technology is unproven and a supply chain for hydrogen fuel is not established. This technology could not feasibly be deployed in time to meet the need, and its cost and fuel availability is highly uncertain.
CDM paired with non-emitting resources	Incremental CDM cannot resolve the rationale by which different non-emitting resources were screened out (e.g. long development timelines, commercial unavailability, inability for batteries to recharge due to the long duration of the need, etc.). While incremental targeted CDM is generally capable of impacting need characteristics to an extent, the large size of the identified need, near-term timing, and long duration, limit how much additional CDM could address supply resource exclusion rationale.

4.4 New Gas-Fired Generation

While gas-fired generation has been screened out as a viable alternative (as further described in this section), an economic analysis comparing gas-fired generation to the proposed project has been provided for benchmarking and illustration purposes (see section 5). Gas-fired generation was selected as the benchmark because it can technically meet the characteristics of the identified capacity need and is cost-effective.

In the current, rapidly changing policy and market environment, there are several risks inherent to a gas generation option that have led the IESO to eliminate it as a viable alternative:

- There are no current proposals or solid interest in building a Combined Cycle Gas Turbine ("CCGT") gas generator in the area which requires lead times of at least 3 years, thus there is a significant risk that it could not be developed as quickly as the transmission alternative (which has already undergone significant development work) due to uncertainties related to permitting, environmental assessments, and supply chain issues.
- There may be limited local support for an emitting resource in an environment moving toward de-carbonization.
- Required gas delivery and management services may be unavailable or prohibitively expensive, impacting reliability or cost. The actual cost to build in the required location may exceed generic cost estimates.
- Recent policy direction to pursue other resources add to uncertainty around the future of gas generation in Ontario.[19]

[19] Refer to *Powering Ontario's Growth* which outlines the steps to meet the needs of the 2030's and beyond and create an emissions-free electricity system (https://www.ontario.ca/page/powering-ontarios-growth)

5. Economic Assessment

The IESO conducted an economic assessment to compare a conceptual gas-fired generation alternative to the Project. Although the LTEP identified the Project in stages, and the IESO's recommendations to proceed with construction were made individually for Phase 1 and Phase 2 based on the forecasts at the time of these recommendations, this analysis considers the Project as a whole (i.e., both Phase 1 and Phase 2). In part, this reflects that both phases are being presented together in a single Leave to Construct application. More importantly, the majority of the forecast electricity demand growth in the region is located such that it drives the need for both phases of the Project. Similarly, a single supply resource sited in the right location could be an alternative to both phases. Therefore, it makes sense to consider the Project as a whole in the evaluation.

Natural gas generation was selected as the non-wires proxy for this assessment for its technical capabilities of addressing the needs and its low cost relative to other the non-wires alternatives that have been screened out.[20]

The assessment was conducted for each demand forecast scenario, to test the economics under a variety of outcomes. The generation was sized to match the size and profile of the need under each demand forecast scenario. A range of CCGT options were considered, with the specific technology size selected for each forecast scenario according to the peak capacity need and the number of hours it would be expected to run. Key economic assessment assumptions are described below.

Expected Lifetimes

The analysis was conducted for a 70-year period, to reflect the expected lifetime of the transmission option. The gas generation was assumed to be replaced like-for-like at the end of its expected useful lifetime (30 years) to enable a comparison with the expected lifetime of transmission.

Costs

The capital cost estimate for the Project was provided by Hydro One and is consistent with the information provided in the leave to construct application (i.e., $1.2 billion including line and station costs). Capital cost estimates for the gas generation alternative were based on benchmark capital and operating cost characteristics for each CCGT resource size, whereby the overnight capital cost ranges from $1,830/kW to $3,350/kW, based on an independent consultant report conducted for the IESO.[21]

Ongoing Operating and Maintenance ("O&M") costs were also included for both transmission and gas generation alternatives. The transmission O&M costs were estimated to be 1% of capital costs based on historical transmission cost builds. The generation O&M are obtained from a consultant report

[20] A hybrid non-emitting resource alternative in which gas generation is installed initially but is then replaced with SMRs after 17 years was also considered. This option is costlier than a gas-only scenario and performs worse in the economic analysis against the transmission alternative.

[21] This is a commercially purchased report to the IESO on costs of gas generation in Ontario and is not available publically.

independently conducted for the IESO which is the same benchmark consultant report used for the capital cost assumptions for the varying gas plant sizes.

Capacity Value

The gas-generation alternative was not assumed to provide any system capacity value due to eastbound constraints on several key interfaces between the Region and southern Ontario, including within the Region itself, that "bottle" existing generation in the Northwest.

Calculation of Net Present Value ("NPV")

Using the above inputs, a net present value (NPV $2022) was calculated for each of the options at a real Social Discount Rate of 4% to reflect the value of social infrastructure projects today. This social discount rate is consistent with that used by provincial ministries for assessments. Varying this rate does not impact the preference for transmission over the gas generation alternative because the same rate applies to both alternatives.

Economic Analysis Results

Table 6 below provides the results of the economic analysis. As noted in section 4.1, it is expected that dynamic reactive support will be required in addition to the Project if demand growth exceeds a Moderate Growth scenario and this would cost roughly $100-150 million.[22]

Table 6 | Economic Assessment of Transmission and Local Gas Generation Resource

Demand Scenario	Generation Resource Technology	Generation Resource Size (MW)[23]	Cost of Generation Alternative (NPV $2022M)[24]	Cost of Transmission Alternative (NPV $2022M)	Cost Advantage of Transmission Relative to Generation (NPV $2022M)
Business As Usual	CCGT	204	$2,635	$2,500	$135
Limited Growth	CCGT	340	$4,165	$3,350	$815
Moderate Growth	CCGT	356	$4,950	$3,855	$1,095
Strong Growth	CCGT	452	$6,765	$4,845	$1,920

As noted above, it is expected that dynamic reactive support will be required in addition to the Project if demand growth exceeds a Moderate Growth scenario and this would cost roughly $100-150 million. Based on this economic assessment, the difference in the NPV of the transmission alternative relative to the gas generation alternative is large enough that transmission is still cost-effective when this additional requirement is considered.

[22] The actual cost will depend on the number, size and location of devices. This is a ballpark estimate based on recent similar project cost estimates.

[23] Generation was sized to not rely on load rejection after system reinforcement.

[24] As per deliverability assessment, system benefit of a new local generation in the NW is zero percent

Based on the results shown in Table 6, the Project is cost-effective relative to a conceptual gas-generation alternative under all four demand forecast scenarios. Additional details on the economic analysis assumptions are provided in Appendix E.

6. Rationale for the Waasigan Project

The need identified in the Region is based on an outlook for growth based largely on the development of new mining projects and the electrification of existing mining activities in the Region.

The Region's electricity system today is very close to its capacity and, due to the size of proposed mining projects, if even one of the larger projects develops and seeks grid connection in the Region, there will be an immediate need for additional supply capacity. The risk associated with not building that capacity now is that new customers may not be able to connect or reliability in the Region may be degraded. Both these outcomes can be expected to stifle further growth.

Local stakeholders and communities have expressed support over the years for transmission expansion to enable growth and economic potential in the Region, citing that one of the reasons holding back new industrial development is a lack of available electricity supply. Furthermore, the Ontario Ministry of Energy has recently directed the IESO to accelerate the development of new transmission infrastructure in Northern Ontario[25].

The Project is the recommended alternative as it improves system capability and is technically feasible in meeting the Region's supply capacity needs up to a Moderate Growth scenario, while also providing a solid foundation to support the Strong Growth forecast scenario. Furthermore, it is the most cost-effective alternative in every scenario when compared to a benchmark gas generation alternative.

The Project, in addition to addressing the identified needs, would provide additional system benefits.[26] While this evidence has focused on constraints on westbound transfers into the Region, eastbound transfers out of the Region are also constrained today. This does not pose a customer reliability risk, but it does have an economic impact as generation resources sited in the Region, as well as imports from Manitoba or Minnesota, that would otherwise be economic are often constrained down to respect system operating limits. This has also limited the development of new generation resources in the Region that would add congestion to the system. The Project would increase transfer capability out of the Region, alleviating this constraint. Combined with other transmission reinforcements that have recently come in service (i.e., East-West Tie expansion)[27] or are planned (i.e., Northeast Bulk transmission reinforcement)[28], the Project could help to unlock future resource

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[25] https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-the-Minister-of-Energy-20230710-Powering-Ontarios-Growth.ashx

[26] These benefits are qualitative in nature and are not captured in the economic analysis.

[27] https://www.ieso.ca/en/get-involved/regional-planning/northwest-ontario/bulk-planning

[28] https://ieso.ca/en/Get-Involved/Regional-Planning/Northeast-Ontario/Bulk-Planning

development potential in the Region. If demand growth continues and further system expansion is needed in the future, additional transmission capability could also enable a wider set of resource alternatives to viably meet the needs, because they could have greater system benefits.

Taking all the above considerations into account, the IESO recommends the Project as the only alternative that is feasible and implementable to supply forecast electricity demand growth in the Region, and that performs well in an economic evaluation against the conceptual alternative of a gas-fired generating facility.

Appendix A: Winter Capacity Needs

The winter demand forecast scenarios and LMCs for the TWM and MMW interfaces are shown in Figure 7 and Figure 8 below. The size of the winter capacity need for the TWM and MMW interfaces under each forecast scenario are shown in Table 7 and Table 8 below.

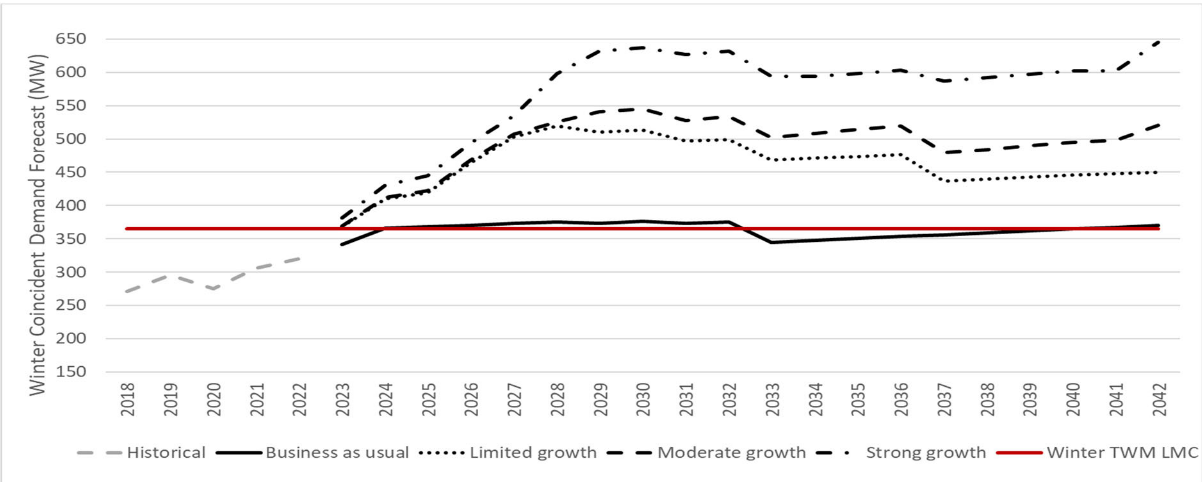

Figure 7 | Winter LMC and Demand Forecast Scenarios for the TWM Interface

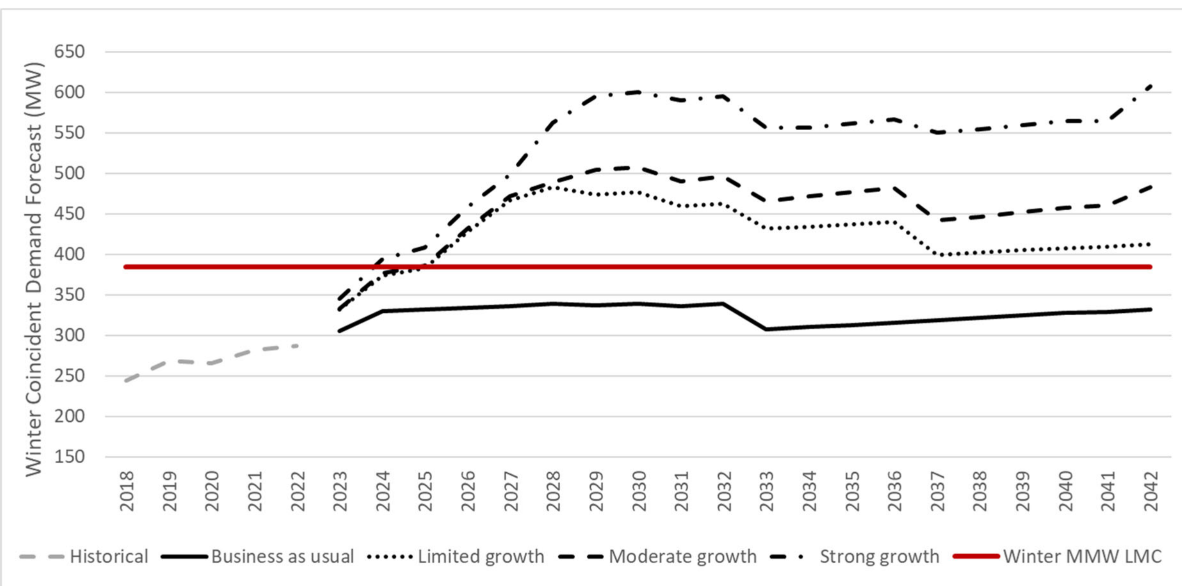

Figure 8 | Winter LMC and Demand Forecast Scenarios for the MMW Interface

Table 7| Maximum TWM Winter Capacity Need by Scenario

Scenario	Highest Forecast Winter Peak Demand	Size of Highest Capacity Need[29]	Year of Highest Capacity Need
Business As Usual	376 MW	11 MW	2030
Limited Growth	520 MW	155 MW	2028
Moderate Growth	545 MW	180 MW	2030
Strong Growth	645 MW	280 MW	2042

Table 8| Maximum MMW Winter Capacity Need by Scenario

Scenario	Highest Forecast Summer Peak Demand	Size of Highest Capacity Need[29]	Year of Highest Capacity Need
Business As Usual	340 MW	-	2030
Limited Growth	483 MW	98 MW	2028
Moderate Growth	508 MW	123 MW	2030
Strong Growth	607 MW	222 MW	2042

[29] 150 MW of load rejection was assumed to be available as a post-contingency control action in the derivation of the LMCs for the existing system.

Appendix B: Mines Included in the IESO's Project-Based Forecast

Table 9 |Existing Mines

Mine Name	Owner	Location	End Date
Musselwhite	Newmont Goldcorp	Pickle Lake	2030
Rainy River	New Gold	Fort Frances	2032
Red Lake Complex	Evolution Mining	Red Lake	2040
Pure Gold (Madsen)	Pure Gold Mining	Red Lake	2033

Table 10 |Future Mines

Project Name	Owner	Location	Expected In-service Date
Battle North (Bateman)	Evolution Mining	Red Lake	2023
Hammond Reef	Agnico Eagle	Atikokan	2026
Springpole	First Mining Gold	Cat Lake	2025
Goliath	Treasure Metals	Dryden	2025
PAK Lithium	Frontier Lithium	Red Lake	2026
Separation Rapids	Avalon Advanced Metals	Kenora	2026
Cameron	First Mining Gold	Nest Falls	2027
Great Bear	Kinross Gold	Red Lake	2024

Appendix C: Incremental Targeted CDM Analysis Details

The IESO considers several standard criteria in evaluating whether incremental targeted CDM is a potential solution to an identified regional or bulk planning need. Based on these criteria, the IESO firmly ruled out incremental targeted CDM solution as a feasible solution to meet the Region's identified capacity needs, particularly due to the timing, absolute size of need, and size of the need relative to total demand (see Screening Criteria #1-3 below). Per standard regional planning practice, as the CDM solution did not pass this screening stage, a regional achievable potential estimate was not produced.

Details of the IESO's assessment that led to the decision to rule CDM out as an alternative to the Project are provided below.

Screening Criteria #1: Timing of need

Description: Due to the time required to design and launch targeted CDM initiatives and the gradual, cumulative nature by which CDM initiatives deliver peak demand relief, it is not feasible to address near-term needs with targeted CDM. Generally, needs in 5-10 years are considered optimal candidates for targeted CDM solutions.

Exceptions may be made where planning needs are immediate (e.g. load may exceed the rated LMC of the existing wires infrastructure today under certain conditions) and targeted CDM can contribute to managing reliability risk while a longer lead-time wires solution is implemented.

Regional Need (Timing):

Scenario	Need timing
Business As Usual	2023
Limited Growth	2023
Moderate Growth	2023
Strong Growth	2023

Analysis: For scenarios that show a need, the need is in the near future which challenges the feasibility of a CDM non-wires solution.

Screening Criteria #2: Size of need

Description: Through the 2021-2024 Conservation and Demand Management (CDM) Framework's Local Initiatives Program, which is the primary mechanism available for targeting incremental CDM to address regional needs, the IESO is able to target incremental CDM (above and beyond the province-wide CDM programs) to specific geographic areas with identified regional or bulk planning needs. This program is currently the primary mechanism available for targeting incremental CDM. The program has a peak demand savings target of 96.4 MW and an associated budget of $139.7M for the four-year term of the framework.

Regional Need Timing):

Scenario	Size of need (Year 1)
Business As Usual	172 MW
Limited Growth	198 MW
Moderate Growth	198 MW
Strong Growth	210 MW

Analysis: Notwithstanding existing target and budget commitments, the needs under all three scenarios significantly exceed the Local Initiative Program's available target and budget for incremental targeted CDM.

Screening Criteria #3: Size of need as a percentage of demand forecast

Description: Informed by the results of recent CDM Achievable Potential Studies, CDM programs are not expected to be able to deliver more than a 2% reduction in peak demand on an annual basis. Consequently, targeted CDM is unlikely to be a feasible solution where needs are growing rapidly and represent more than 2% of the total demand forecast.

Regional Need (% of Forecast Demand):

Scenario	2023 Need as Percentage of 2023 Forecasted Demand
Business As Usual	62%
Limited Growth	65%
Moderate Growth	65%
Strong Growth	66%

Analysis: The pace of demand growth in the Region vastly outstrips the ability to manage peak demand through targeted CDM without continued reliance on load rejection. Targeted CDM is not a viable non-wires solution.

Screening Criteria #4: Coincidence with provincial system peak

Description: Targeting regional needs that occur during the provincial system's summer peak demand period (which primarily drives provincial system capacity needs) maximizes the value of the targeted CDM to the provincial system and, by extension, provincial ratepayers. The Local Initiatives

Program requires that local programs be cost-effective based on provincial system benefits alone, reflecting that these initiatives are funded by all provincial ratepayers.

West of Thunder Bay Need: Needs forecasted to appear in both summer and winter.

Analysis: Generally, regional need coincidence with provincial system peak means a targeted CDM solution would contribute to meeting provincial capacity needs. However; transmission constraints between the Northwest and load centres in Southern Ontario may limit the impact of local incremental CDM on provincial system needs (see discussion of "bottling" transmission constraints in the assessment of new gas-fired generation as wires alternatives). Additionally, note that dual-season needs present additional challenges from a regional achievable potential and program design perspective (particularly due to implications for air-conditioning measures).

Screening Criteria #5: Community and utility support

Description: Strong support from local communities and utilities for targeted CDM enhances the likelihood of achieving material peak demand savings. Local utility support is required to define the geographic boundaries of the area served by the relevant transmission infrastructure and to provide customer information necessary for effective program design.

West of Thunder Bay Need: Unclear support for targeted CDM across the Region. Demonstrated strong support for a wires solution from certain communities and mining customers (which represent significant share of current and forecasted demand). Synergy North has expressed interest in exploring non-wires alternatives including incremental CDM to address an anticipated local need in Kenora identified in the Northwest IRRP, which falls within the Region but represents a small portion of the area's demand.

Analysis: Strong support for a wires solution from certain communities and major customers may challenge design and delivery of targeted CDM initiatives.

Screen Criteria #6: Other relevant factors

Description: The characteristics of Ontario's electricity planning regions and sub-regions vary widely by customer composition, population density, community priorities, etc. Consequently, it may be appropriate to consider relevant context-specific factors in certain circumstances.

West of Thunder Bay Need: The study area is notable in the extent to which current and forecasted future demand is driven by mines and other very large industrial customers. These large "lumpy" loads translate into large "lumpy" CDM opportunities.

Analysis: Areas like the study area where a relatively small number of customers represent a large share of demand may represent greater risk for successful attainment of peak demand reduction through targeted CDM programs. This is because program success becomes contingent on decision-making by a limited pool of customers instead of a large and diverse pool of customers for which planners can more reasonably make generalized assumptions about program participation.

Appendix D: Posterity Group's Electric Vehicle & Mining Sector Market Study Final Report

In 2022, the IESO retained the Posterity Group (and its specialist subcontractors) to undertake a variety of research regarding forecasting long-term provincial demand from the mining and Electric Vehicle (EV) sectors, including producing sectoral demand forecasts under different scenarios. The IESO has leveraged certain findings from this research to inform development of the "Moderate Growth" and "Strong Growth" demand forecast scenarios for the Region, such as assumptions about mine electrification and longer-term mineral production. The IESO opted to leverage certain findings instead of adopting Posterity Group's forecasts in their entirety as:

1. New information about specific mining projects became available after the conclusion of the Posterity Group project's data collection phase, and
2. The priority of the Posterity Group project was to enhance the IESO's mining sector demand forecast at the provincial-scale and over a twenty-year timeframe. To this end, Posterity Group's report makes assumptions about general trends impacting demand which may not accurately scale to a smaller region and shorter timeframe, and hence local intelligence was prioritized in the development of the demand forecast scenarios for the Region.

The mining sector content of the *Electric Vehicle & Mining Sector Market Study Final Report* is included in this submission as an attachment. The Electric Vehicle sector content has largely been redacted as it is not relevant to this submission.

Appendix E – Economic Assumptions

The following is a list of the assumptions made in the economic analysis comparing the Project to a conceptual gas-generation alternative:

1. The NPV of the cash flows is expressed in 2022 CAD.
2. The CAD/US exchange rate was assumed to be 1.30 for the study period.
3. Natural gas price forecast is as per Sproule Outlook @ Dawn.
4. Marginal Cost forecast for transmission energy cost is as per the IESO's 2022 Annual Planning Outlook (APO).
5. The NPV analysis was conducted using a 4% real social discount rate, consistent with the rate used by the provincial ministries for assessments. A long-term annual inflation rate of 2% is assumed.
6. The life of the transformer station upgrades was assumed to be 45 years; the life of the transmission lines was assumed to be 70 years; and the life of a gas generator was assumed to be 30 years.
7. Development timeline for gas-fired generation assumed to be 3 years.
8. The size of the resource option was determined by a deterministic capacity assessment. A gas alternative was identified as one of the lowest-cost resource alternatives for the Waasigan region, based on escalating values from a previous study independently conducted for the IESO.[30]
9. Carbon pricing assumptions are based on the proposed Federal carbon price increase that escalates to \$170/tCO2e by 2030. Thereafter, the \$170/tCO2e assumption is held constant in real dollars for the forecast period. The benchmark (tCO2e/GWh) for new gas facilities is assumed to be eliminated by 2030.
10. The assessment was performed from an electricity consumer perspective and included all costs incurred by project developers, which were assumed to be passed on to consumers.

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

Appendix F – Posterity Group Report

POSTERITY GROUP

Electric Vehicle & Mining Sector Market Study

Final Report

Date: February 9, 2023

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Contents

1 Introduction

The Ontario Independent Electricity System Operator (IESO) procured Posterity Group (PG) to validate IESO's existing electricity demand forecast methods for the electric vehicle (EV) and mining sectors in Ontario, to identify opportunities for enhancing these forecasts, and to produce such enhanced forecasts. These forecasts are used for bulk transmission system planning and to help inform provincial stakeholder dialogue that underpins energy policy and planning decisions in Ontario. To conduct the analysis, PG assembled a consulting team that includes Transition Accelerator (TA), an energy system transition expert with experience in the EV sector, and EELO Solutions (a mining industry expert).

The mining sector is a significant contributor to Ontario's economy and represents a significant share of Ontario's industrial electricity demand. Information about future known projects suggests electricity demand attributable to this sector will grow in the short to medium. Forecast uncertainty exists beyond this known projects horizon. Some research and stakeholders indicate that global energy system decarbonization efforts will increase demand for minerals and that this increase will be reflected in further growth of the Ontario mining sector in the long term.

[redacted]

PG builds on IESO's existing forecast methods by employing a combination of econometrics and bottom-up forecasting in order to produce a set of forecast scenarios. PG gathered input data for the analysis by conducting primary and secondary research and interviewing key stakeholders for the mining and EV sectors. These methods and resulting scenarios provide a structured framework for thinking about how future electricity demand can behave. Due to the long-term forecast horizon, the individual scenario results are subject to forecast uncertainty. For this reason, PG prepared a PowerBI dashboard for IESO that enables running sensitivities on the scenario results. This approach does not assign probabilities to the individual scenarios. Experience from other jurisdictions suggests that probability assignments may be possible via a parametric analysis. This involves running the analysis numerous times, each time with slightly altered input assumptions, and examining how the analysis results cluster. Denser clusters of forecast trajectories denote higher probabilities. To derive a meaningful signal from a parametric analysis, the frequency of individual input assumptions across all parametric model runs must also contain meaningful information (rather than assuming that assumptions change randomly from one model run to another). Developing such meaningful input information poses a challenge for long forecast horizons (since they entail significant uncertainty about future events). PG has used Delphi panels of experts to produce such input information for clients in other jurisdictions. Such a panel of experts approach is also common outside the energy forecasting domain.

Section 2 of this report summarizes the scenario results and outlines key uncertainties and opportunities for further research. Section 3 details the mining sector analysis and includes a description of the forecast methods PG used, the scenario construction, the steps used to prepare the quantitative analysis model, and the annual and peak demand results. Section 4 provides these details for the EV sector.

2 Results Summary

This section provides an overview of the scenarios within the Mining and EV models and highlights the keys results from each of the models. Full results and analysis can be viewed in Sections 3.5 and 4.5.

The mining forecast model was run for three different scenarios, each representing different pathways and plotlines for the mining sector in Ontario between 2021 and 2050. The Active Electrification & High Production scenario, representing the high load scenario, expects the mining sector to reach the net zero goals laid out by the Ontario government and increase production to match the global demand expected to accompany the energy transition (including early infrastructure investment timing for the Ring of Fire resource basin). The Reference Case & Ring of Fire scenario, representing the medium load scenario, assumes that Ontario will continue its current energy and industrial policy trajectories and expects a later infrastructure investment timeframe for the Ring of Fire. Lastly, the Economic Uncertainty and Global Competition scenario represents the low load scenario and assumes a lower mineral demand, little investments from mining projects to transition towards net zero technologies and no infrastructure investment in the Ring of Fire before 2050.

[redacted]

2.1 Annual Consumption

Exhibit 1 – Annual Mining Consumption by Scenario

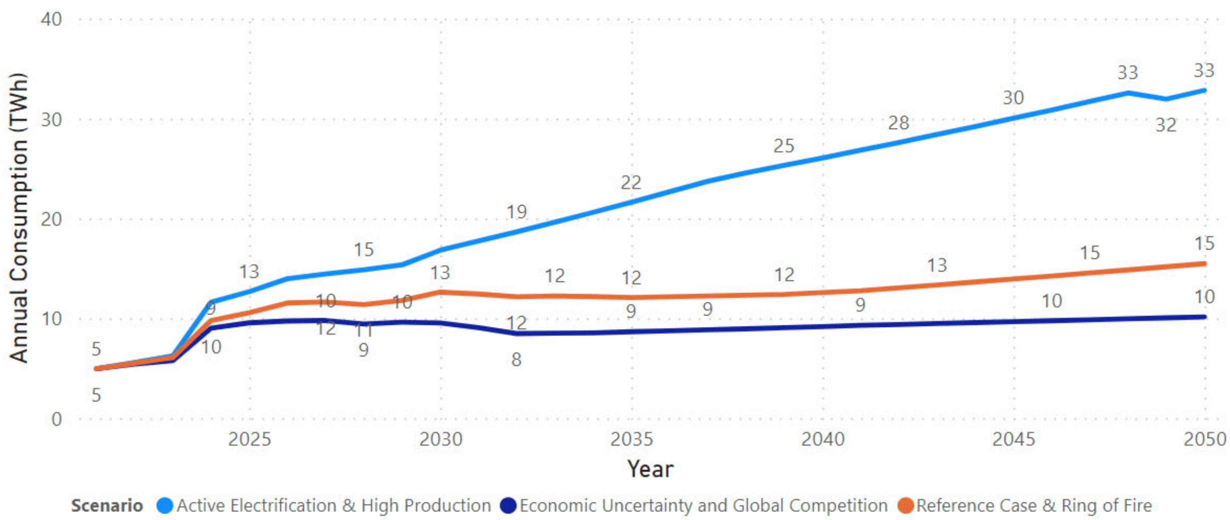

Exhibit 1 displays the forecasted annual consumption for each of the three scenarios in the mining model between 2021 and 2050. Due to its more aggressive mineral demand and net zero technology adoption assumptions, the Active Electrification & High Production scenario estimates an annual consumption of roughly 33 TWh by 2050. This more than doubles the estimate for the Reference Case & Ring of Fire scenario, which is expected to have an annual consumption of roughly 15 TWh by 2050. The Economic Uncertainty and Global Competition scenario has the lowest forecasted annual consumption by 2050 at roughly 10 TWh.

While the annual consumption is estimated to have been roughly 5 TWh for all scenarios in 2021, a better indicator of the long-term growth that is to be expected in the mining sector would be to compare the annual consumption forecasts in 2050 to the consumption expected between 2026 and 2030. The annual consumption between 2026 and 2030 signifies the peak of the known projects that are currently in construction or set to come into production in the next few years. From this, it can be seen that the Active Electrification & High Production scenario continues on this upward trend, the Reference Case & Ring of Fire scenario slows down to a gradual increase in consumption out to 2050 and the Economic Uncertainty and Global Competition scenario essentially plateaus and stays at a relatively constant consumption level moving into the future.

[redacted]

[redacted]

2.2 Peak Demand

Exhibit 3 – Mining Peak Demand by Scenario

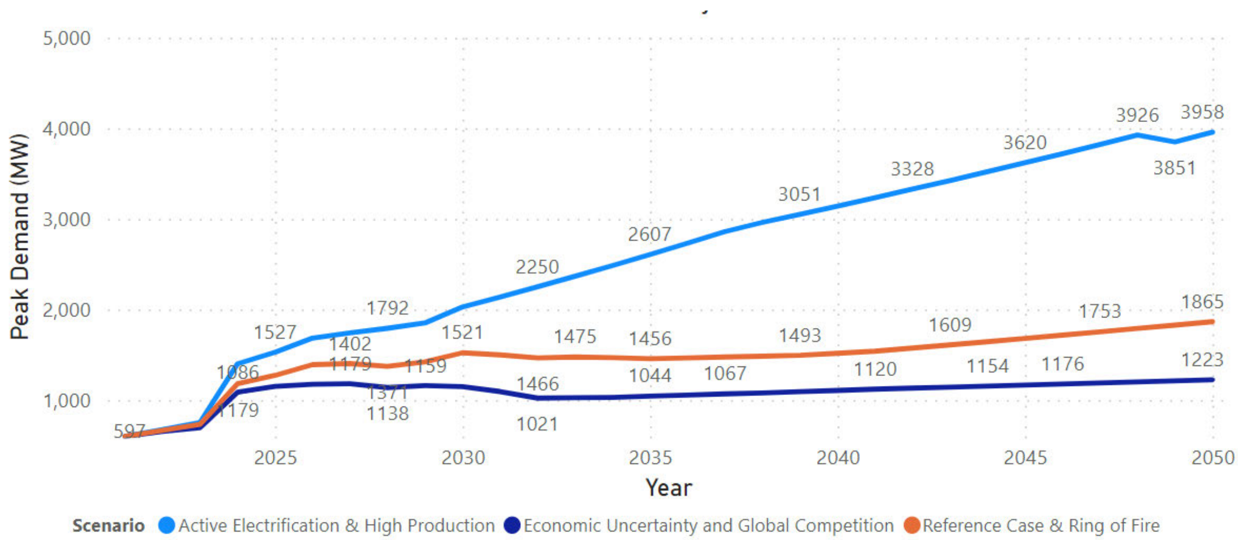

Exhibit 3 displays the forecasted peak demand for each of the three scenarios in the mining model between 2021 and 2050. The expected peak demand in 2050 is approximately 4,000 MW for the Active Electrification & High Production scenario, approximately 1,900 MW for the Reference Case & Ring of Fire scenario and approximately 1,200 MW for the Economic Uncertainty and Global Competition scenario. Since the peak demand and annual consumption values can be derived from one another by applying a peak factor, Exhibit 1 and 3 have identical shapes and will display identical characteristics.

[redacted]

[redacted]

In addition to peak demand values across the forecasted period, the 8760 load profiles for both the mining and EV model, broken down by regions, are provided in supplementary Excel workbooks. Since mining load is generally very flat, the mining model only used the load shape that was provided by the IESO. [redacted]

2.3 Uncertainties

The mining and EV forecast incorporates the latest information made available to PG, including data that had been sourced up until January 2023. The electrification of the mining and transportation sectors are gaining momentum and evolving rapidly through a combination of technological innovation, government policies, and changing consumer/shareholder attitudes. As new data evolves over time, the forecast will need to be updated in order to accurately capture the direction of the two sectors in Ontario. Specific aspects of uncertainty within the model and opportunities for further research can be viewed in Sections 3.5.4 and 4.5.3.

3 Mining Sector

3.1 Forecast Method

PG initiated the analysis by reviewing IESO's existing forecast methods and gathering third-party inputs on best practices. This process yielded the following insights.

IESO provided guidance on how several aspects of the forecast methodology should behave:

- Maintain a project-based forecast approach in the short-term forecast horizon (<=5 years).

[redacted]

- In the short-term forecast horizon, maintain sub-regional granularity for known projects (to help inform transmission planners).
- Maintain flexibility in the results layer for updating frequently changing inputs.
- Include functionality for estimating uncertain electric loads from previously unknown projects both within and outside the Ring of Fire resource basin.

Findings from third-party utility forecasts provide additional guidance:

- Project probability-based methods are best practice for mining forecasts.
- Project probability-based forecasts can be supplemented by reference to third-party mining production forecasts to account for uncertainty beyond the short term.
- Consider binary rather than probability-based forecast load assignment for a forecast horizon of <=3 years when you are determining new project start-ups or project closures (closure risk should be included in the forecast).

Mining industry experts who are familiar with IESO's forecast methods, highlight the following considerations for an updated forecast methodology:

- Predicting mine lifetimes is difficult since operators often extend projects depending on commodity price trends.
- Mine capital is globally flighty and makes investment decisions based on numerous factors, so assuming that Ontario will maintain a specific share of global mining production may be unrealistic.
- Consider simplifying the constituent likelihood parameters for the probability-based forecast.

PG's experience from preparing long-term forecasts for numerous clients across multiple sectors of the economy reinforces findings from the other data sources:

- Simplifying and better defining (or contextualizing) the process for assigning likelihood factors can reduce noise when forecasters decide how to assign load probabilities (i.e., creating a somewhat simpler and very prescriptive likelihood rating matrix may be useful).
- Relying on publicly available third-party forecasts for method inputs can reduce complexity.

Based on these insights, PG (in consultation with IESO) developed the following three uncertainty categories that each are subject to different analysis drivers and methods:

- Known Projects – Future mining projects or expansions that are concrete and are accompanied by supporting information.
- Unknown Projects outside Ring of Fire – Potential future mining projects outside the Ring of Fire resource basin that are not concrete and thus lack supporting project-specific information.
- Unknown Projects in Ring of Fire – Potential future mining projects in the Ring of Fire resource basin that are not concrete and thus lack supporting project-specific information.

The following sources of uncertainty apply across each uncertainty category and the short- versus the medium- and long-term forecast horizons:

Exhibit 5 – Sources of Forecast Uncertainty

Uncertainty Category	Short Term (Forecast Horizon <= 5 Years)	Medium & Long Term (Forecast Horizon >5 Years)
Known Projects	• Commodity price • Funding status • Anticipated in-service date • Development process stage	• Commodity price • Electricity intensity • Electric load shape
Unknown Projects (Outside Ring of Fire)	• N/A – projects would be known if they had reasonable probability of being realized within the short term	• Increase/decrease in mining production • Maximum resource base • Electricity intensity • Electric load shape
Unknown Projects in Ring of Fire	• N/A – projects would be known if they had reasonable probability of being realized within the short term	• Increase/decrease in mining production • Maximum resource base • Electricity intensity • Electric load shape • Availability of public infrastructure that supports development of mining projects in the resource basin (e.g., roads and power transmission lines)

PG developed a combination of forecast methods to capitalize on the strengths of IESO's current forecast method, while also meeting requests for greater forecast functionality and implementing identified opportunities for improvement. Exhibit 2 below outlines the proposed combination of methods across each combination of uncertainty category and forecast horizon.

Exhibit 6 – Combination of Forecast Methods

Uncertainty Category	Short Term (Forecast Horizon <= 5 Years)	Medium & Long Term (Forecast Horizon >5 Years)	Comments
Known Projects	• Continue project-probability based method • Remove anticipated in-service date for assigning project probabilities – simply assign load to the most likely start date • Simplify development stages – Pre-System Impact Assessment (SIA)/Technical Feasibility Study (TFS), SIA/TFS received, construction and production • Use binary rather than probability-based decisions for forecast horizon <= 1 years if dealing with project opening/closure	• Supplement short-term load data with two additional factors 1 Range of electricity intensity on new projects 2 Range of electricity load shapes for new and existing projects	• Shareholder-owned mines must prepare NI43-101 disclosure reports for new projects or project expansions; these reports may provide additional information that IESO can use for future forecasts (in addition to the data it obtains from its mine engagement processes). The disclosure reports can be accessed by doing an internet search on the relevant mining operator name and SEDAR (System for Electronic Document Analysis and Retrieval). • We did not find any reliable correlation between commodity price trends and known project activity; as such, we excluded this uncertainty driver from the forecast methods. • As further explained in Section 3.2.3, we did not find sufficient evidence to warrant disaggregating load shapes across segments, regions, and forecast years – however, this functionality does exist

Uncertainty Category	Short Term (Forecast Horizon <= 5 Years)	Medium & Long Term (Forecast Horizon >5 Years)	Comments
			in the forecast model if sufficient empirical evidence becomes known.
Unknown Projects (Outside Ring of Fire)	• N/A – projects would be known if they had reasonable probability of being realized within the short term	• Rely on a third-party mining production forecast as a proxy for mining activity • Use the scenario range of electricity intensity and load shapes to examine how energy demand may behave on the basis of the selected production trends	
Unknown Projects in Ring of Fire	• N/A – projects would be known if they had reasonable probability of being realized within the short term	• Rely on a third-party mining production forecast as a proxy for mining activity • Use the scenario range of electricity intensity and load shapes to examine how energy demand may behave on the basis of the selected production trends • Assign the resulting energy demand across years in the time horizon by relying on a range of assumptions for when public infrastructure investment decisions will occur and how quickly mining projects may start production after these investments	

3.2 Data Acquisition

PG conducted primary research, secondary research, interviewed key mining sector stakeholders and experts, and circulated a survey to the energy committee members of the Ontario Mining Association (OMA) to prepare input information for the analysis. The following types of information were derived from different input categories:

- Production forecast by mineral type – Secondary research on future mineral demand due to the transition to clean energy via the International Energy Agency (IEA) and S&P Global employment forecasts.
- Historical mining production trends – Secondary research on natural resource reserves data from Statistics Canada.
- Mining electricity intensity – Primary research on historic IESO load data, analysis of an IESO electrification case study, interviews with mine operators and industry experts, and the OMA survey.
- Mining electricity load shapes – Primary research on historic IESO load data, and interviews with mine operators and industry experts.
- Known Projects characteristics – IESO engagement with mine operators, interviews with mine operators, and the OMA survey.

3.2.1 Impact of Economy-Wide Electrification on Demand for Mining Products & Mining Electrical Load

Multiple sources suggest that the global push for renewable technologies and EVs will increase the demand for minerals such as copper, lithium and nickel over the coming decades because renewable energy technologies generally require more minerals to build than their fossil-fuel based counterparts. Minerals mined in high frequency in Ontario, such as nickel and copper, are expected to see a growth in global demand in 2040 relative to 2020 by as much as seven and two times, respectively, given currently stated policies.[3] Lithium, a mineral used in batteries for EVs and grid energy storage, is expected to see the largest growth of all minerals in demand. According to stakeholder interviews, numerous manufacturing plants in Ontario that have been announced will need sources of lithium, so there is an incentive for these end users to support the development of new and existing mines.

3.2.2 Impact of Electrification & Fuel Switching in the Mining Sector

Information gathered from stakeholder interviews suggests that mining companies have expressed interest in moving towards net zero operations through electrification, as electricity is almost always the cheapest energy source available. Even during economic downturns, shareholder and economic pressure will drive mining operations to turn towards electrification if the option is available.[4] If cheap electricity via the grid is not available to mines, many will explore the option of generating their own electricity, particularly through solar and wind, before reverting to the use of more expensive options such as natural gas or diesel. Therefore, a lack of access to electricity provided by the grid will add to the cost of mining project which could potentially prevent them from receiving investor approval.

Electrification in the mining sector is expected to be a gradual process as technologies become more prevalent and feasible within the industry although there could be delays due to competing demand for batteries and long-haul vehicles in other sectors. However, with access to affordable electricity, mining

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[3] https://www.iea.org/reports/the-role-of-critical-minerals-in-clean-energy-transitions/executive-summary

[4] Aside from global economic factors, the global investment regime is becoming more sensitive to environmental impacts, so some shareholders would favour low carbon energy investments even if these were not the cheapest energy source.

companies have a vested interest to transition more of their operations to be powered by electricity as this will lower their operating costs along with their greenhouse gas (GHG) emissions.

3.2.3 Insights on the Evolution of Mining Electric Load Shapes

Throughout all research and discussions with key mining sector stakeholders, the consensus is that mines will generally operate at full capacity for as much of the day as possible, including weekends. As there is a large up-front monetary and time investment before any mining production can begin, companies will try to operate their mining projects as much as they can to recoup the initial costs and begin to make a profit. This results in a load shape that is essentially flat with no large peaks or troughs.

Additionally, there is no evidence to suggest that mass electrification will drastically change the load shape from its current flat profile as it will always be in the mines' best interest to be operating at full capacity. Because of this, the current load shape employed by the IESO for mining operations is reasonable to be used for all current and future mining projects within this analysis.

3.3 Forecast Scenarios

The forecast methods and data acquired during research yield the following critical uncertainties that distinguish forecast scenarios from each other.

3.3.1 Electricity Intensity (Impacts Known and Unknown Projects)

Each scenario will use one of the following input assumptions:

- Meeting 2050 Targets – Electricity intensity evolves in alignment with 100% of mines reaching net zero carbon emissions by 2050. This aligns with the federal government's commitment to reach net zero carbon emissions by 2050.
- Stated Objectives – Electricity intensity evolves in alignment with 40% of mines reaching net zero carbon emissions by 2050. This aligns with the more than half of Ontario mines that have currently set carbon reduction targets and the almost 40% of mines having established long term net zero targets.[5]
- Business as Usual (BAU) – Electricity intensity evolves in alignment with 20% of mines reaching net zero carbon emissions by 2050. Even in the business as usual setting, shareholder interest in saving costs and reducing environmental impacts is expected to drive a certain proportion of mines in Ontario to adopt electrification technologies and practices.

Using input from mine operators, industry experts, and forecasters, the increase in electricity demand going from a mine using currently available and conventional technologies in the base year (2021) to a fully electric net zero operating mine is estimated to be the following:

- Underground Mine: Increase of 44% (Factor = 1.44)
- Open Pit Mine: Increase of 104% (Factor = 2.04)

Underground mines are expected to experience less of an increase in electricity demand with electrification since there is already more equipment that has been electrified and the electrification of previously diesel fueled underground haul fleets results in a decrease in the amount of electricity needed

[5] https://oma.on.ca/en/ontario-mining/2022_OMA_Economic_Research_Report.pdf

for ventilation. Open pit mines typically rely on more conventional diesel fueled equipment and thus a shift towards a fully electric mine results in a larger increase in electricity when compared to underground mines.

Based on data from IESO's existing mining forecast, we found that 63% of the known mines in Ontario are underground mines and 37% are open pit mines. Lacking any additional concrete evidence, this proportion of underground to open pit mines was used for all years within the forecast, regardless of region, mineral type and whether the projects were known or unknown. Therefore, the inputs for this critical uncertainty break down as follows:

1. Meeting 2050 Targets: 100% of mines in Ontario reach net zero by 2050. This results in an increase of electricity intensity of 66.6% (factor of 1.666).
2. Stated Objectives: 40% of mines in Ontario reach net zero by 2050. This results in an increase of electricity intensity of 26.6% (factor of 1.266).
3. BAU: 20% of mines in Ontario reach net zero by 2050. This results in an increase of electricity intensity of 13.3% (factor of 1.133).

Without additional information on the adoption rates of electrification technologies, the electricity intensity factors were assumed to linearly increase from 1, in 2021, to the factor calculated for 2050, simulating a gradual increase in electrification over the forecast horizon. While this approach might not provide the greatest accuracy over the short-term horizon when analysing individual mining projects, it still provides valuable insights when mining projects are studied in aggregate, even within smaller regions. This is because even if specific mining projects do not electrify at all over this shorter time scale, there will be other mining projects that might electrify more end uses, thus balancing out the average electricity intensity increase.

3.3.2 Forecast Mineral Production Level (Impacts Currently Unknown Projects Emerging in the Future)

Each scenario will use one of the following input assumptions:

- High – Assumes an acceleration of the historical trend by taking into account international data for what volume of minerals will be needed to drive the energy transition (batteries, grid updates, turbines etc.), provincial trends, and, for base metals, Ontario's historical production peak.
- BAU – Previously unknown mines are added to the known mines in alignment with how the historical production level has grown and how mining employment forecasts depict the sector.
- Low – Previously unknown mines are added to the known mines in alignment with how the historical production level has grown and how mining employment forecasts depict the sector. *The BAU and Low forecasts differentiate from each other by using different years as the reference year when applying the employment forecast trends.*

As shown in Exhibit 3, the mechanics of the production forecast critical uncertainty differ by mineral type.

Exhibit 7 – Production Forecast Mechanics by Mineral Type

Forecast Scenario	Gold	Base Metals
High	The general production trend since 1978 for gold in Ontario increases over time. Electricity demand forecasts from the Known Projects (IESO's High and Reference Case[6]) however were both significantly above the trendline produced from the historical data. Electricity demand for gold mines in IESO's Known Projects forecast peaks in 2026. With the assumption that past 2026, there are additional unknown mines that continue to increase demand, a trendline of the increase from 2021 to 2026 can be extended out to 2050. This however leads to more than a four-and-a-half-fold increase in production between 2021 and 2050 which appears unreasonably high. In comparison, when the historical production data is extrapolated to 2050, the less than two-fold increase seen in production was assessed to be too conservative for a High scenario. As such and lacking any concrete alternative input data outside the Known Projects horizon, PG uses the average of the historical trend and the trendline from the IESO Known Projects forecast as the High scenario input. This results in an estimated increase in gold production between 2021 and 2050 of roughly 225%. Production is assumed to linearly increase to this value from the peak production seen in the IESO's Known Projects forecast in 2026.	As opposed to the general historical trend seen in gold production, the trendline for the historical base metal production in Ontario dating back to 1978 points downwards. However, multiple sources have expressed that global demand for these minerals will greatly increase in the coming years, driven by the increase in electric vehicles and other renewable energy technologies. One such report from the International Energy Agency (IEA) states that demand for copper and nickel by 2040 could be two and seven times larger, respectively, than it was in 2020.[7] For the High input assumption, this increase in demand was assumed to correlate to an equal increase in production and thus the linear trendline was overlayed on the production data, extending out from 2020 to 2050. IESO's High scenario for Known Projects forecast follows a similar trend to that of the increase in mineral demand outlined by the IEA. The High scenario for known mines flattens out in 2030, but third-party data (such as the IEA report) suggests that demand for base metals globally will increase beyond the Known Projects horizon. While Ontario's share of production to meet this demand is unknown, the High input assumption demonstrates what such a production trend could look like. As such, the High input assumption calculates the production trend from 2021 to 2030 and extends this until the projected production reaches the

[6] The High case includes all mines with all probabilities whereas the Reference case only includes mines that had been assigned a one or two probability rating.

[7] https://www.iea.org/reports/the-role-of-critical-minerals-in-clean-energy-transitions/executive-summary

Forecast Scenario	Gold	Base Metals
		historical provincial maximum. After reaching this maximum, production levels flatten out until 2050, resulting in an increase of production between 2021 and 2050 of approximately 210%.
BAU	To be consistent with the forecast methods for base metal mines, PG does not propose to use the historical production data trendline for the BAU forecast. The base metal historical trendline indicates a decrease in production which is deemed to be unlikely given the expected increase in demand for these minerals. IESO provided employment and Gross Domestic Product (GDP) forecasts for the mining sector in Ontario from S&P Global.[8] A positive correlation exists between historical employment rates and historical mining production. On this basis, PG proposes to use the forecasted growth in employment to set a BAU baseline.[9] By assuming that growth in production is proportional to employment growth, production growth can be forecasted out to 2050. Initial known production for gold in the BAU scenario follows IESO's Reference Case for Known Projects. To provide an intermediate view between the High production forecast and the Low production forecast, it was decided to use 2041 as the reference year for the production (due to employment) growth trend as there is a steep drop off in demand from Known Projects after this year.	For the BAU scenario, the same approach used for the gold production forecast was used for the base metal production forecast. The historical downward trend of production does not align with the expected increase in demand for these metals seen throughout research. As such, PG again uses the growth rate of the S&P Global employment forecast. Like the gold forecast, the BAU input assumption for base metals also follows IESO's Reference Case Known Projects forecast before transitioning to the employment growth trend (using 2041 as the reference year). This leads to a production growth of roughly 110% between 2041 and 2050.

[8] S&P Global forecasts were only provided until 2041 so the forecast was linearly extrapolated to 2050 using the forecasted data between 2021 and 2041.
[9] Forecasted GDP growth was initially considered to be a more accurate proxy for production growth but an increase in GDP of roughly 2.5% between 2021 and 2050 was deemed to be too low, compared to the increase in employment of roughly 35% between 2021 and 2050, given the historical trends and the already-known mining demand that is expected to be installed over the next 20 years.

Forecast Scenario	Gold	Base Metals
	[10] This results in a forecast production increase of roughly 67% between 2021 and 2050.	
Low	The Low production forecast employs the same employment forecast for the mining sector in Ontario from S&P Global but uses 2021 as the reference year instead of 2041. Between 2021 and 2031, the production from Known Projects in the Low scenario is larger than the production due to employment increases which signifies that there are no additional unknown projects. From 2032 onwards, the production due to employment growth trend is larger than the known production and thus, this trend takes over total production forecast until 2050. This results in a forecast production increase of roughly 35% between 2021 and 2050.	The same approach employed for gold production was used for the Low production forecast for base metals. For the base metals, the production due to employment increases did not overtake the known project production until 2034 so the employment trend takes over later than seen for gold production. However, this also results in a forecast production increase of roughly 35% between 2021 and 2050.

3.3.3 Ring of Fire Infrastructure Investment Timing (Impacts Whether Any Electrically Powered Projects Will Emerge in the Ring of Fire)

Each scenario will use one of the following input assumptions:

- Early – Public infrastructure to connect the Ring of Fire is built soon (building transmission infrastructure takes at least 5 years, so the earliest possible date would be 2028 if a decision is made in 2023 – 2030 is a more conservative assumption because IESO estimates 5-7 years development time, and no decision is publicly on the horizon).
- Late – Public infrastructure to connect the Ring of Fire is built later in the forecast horizon (2040 is a reasonable assumption to contrast with 2030 for the Early input assumption).
- None – No public infrastructure is built to enable resource exploration in the Ring of Fire.

Since the Ring of Fire consists of mainly base metals (including large deposits of chromite which is in high demand for stainless steel), production in the Ring of Fire is assumed to grow at the same rate of increase as the High scenario base metal mine production from the rest of the province, between 2021 and 2050. Since the base metal production is assumed to plateau before 2050 once it reaches its historical high point, the rate of production increase seen in the Ring of Fire is not as steep as the initial increase in

[10] Using 2041 as the reference year means that the production in any given year after 2041 is estimated to be the increase in forecasted employment between that year and 2041 multiplied by the production in 2041.

production for base metals outside the Ring of Fire, which is expected to be driven by the increase in global demand for such metals. While both the Early and Late timeline scenarios are assumed to have the same rate of production growth, the difference in production start dates results in the Early timeline scenario forecasting about 90% more Ring of Fire production than the Late timeline scenario by 2050.

3.3.4 Project Probabilities (Impacts Known Projects in the Short and Long Terms)

Each scenario will use one of the following input assumptions:

- High – Probabilities are based on IESO's median project probability assignment matrix and include projects with all likelihoods.
- BAU – Probabilities are based on IESO's median project probability assignment matrix and only include projects with likelihoods of one and two (most likely projects). [11]
- Low – Probabilities are based on IESO's low project probability assignment matrix and only include projects with likelihoods of one and two (most likely projects).

In the IESO's model, each known mining project is assigned a likelihood or probability between one and four which represents the likelihood of electricity demand materializing at the facility. On this scale, one represents the most likely projects and four represents the least likely projects. This approach was replicated for this analysis with some minor simplifications.

- Initial probabilities are assigned based on anticipated service date:
    - In service or one years in the future: 1
    - In service two to three years in the future: 2
    - In service four or more years in the future: 3 or 4 (depending on the stage of the mine)
- Probabilities for mining projects that are four or more years away from being in service are amended based on the stage of the project. Project stages take the commodity prices and funding of the project into account so they represent a good aggregation proxy for these two other factors when assigning probabilities. [12]
    - The SIA/TFS stage is the last stage before construction begins on the mining project. Therefore, any mine that has reached this stage is assigned a probability of three.
    - Any mining project that has not reached the SIA/TFS stage is assigned a probability of four.

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[11] An exception to this is made for known projects in the Ring of Fire as they have probabilities of three and four but are included in this scenario.

[12] No reliable trends or correlations were found when overlaying commodity prices and commodity production. Generally, the commodity price will factor into whether a mine will go through the initial stages of exploration to construction, but once enough money has been invested, mines are likely to continue production, even with decreases in commodity prices. Additionally, the potential use of futures contracts to guarantee revenue, and differences in both operations and mineral ore grade across individual mines, mean that "floor prices", for which it is no longer economical for mines to continue operating, were difficult to determine. This reinforced the decision to roll commodity price up into the project stage when assigning probability values (since the project stage is assumed to inherently capture information about commodity prices that led to the resulting project stage).

- Lastly, expansions or extensions of known mining projects are assigned one probability point higher than their original mines. Since four is the highest probability factor that can be assigned, expansions or extensions of future projects that have already been assigned a four will also be assigned a four.

All the known mining projects were assigned a probability using the criteria described above, except for a select few mines that had contacted the IESO directly with more up-to-date information which prompted the IESO to make manual probability updates. These manual updates were also reflected in PG's model.

Based on the probability, the peak electricity demand of the mine is multiplied by a factor to reflect the certainty of the load materializing. These factors are different for each scenario and can be seen in the exhibit below.

Exhibit 8 – Probability Assignment Matrix

Probability	Probability Factors		
	High	BAU	Low
1 – Most Likely	1	1	1
2 – Likely	0.8	0.8	0.5
3 – Less Likely	0.5	0	0
4 – Least Likely	0.2	0	0

3.3.5 Scenario Plotlines and Sensitivity Analysis

The analysis combines the critical uncertainties into the following scenarios to enable an informed consideration of electricity demand across possible alternate futures.

Exhibit 9 – Mining Sector Scenario Plotlines

ID	Scenario 1	Scenario 2	Scenario 3
Name	Active Electrification & High Production	Reference Case & Ring of Fire	Economic Uncertainty and Global Competition
Plotline	Ontario executes on 2050 decarbonization targets and adopts active industrial policies to support local production of inputs to the energy transition	Ontario continues its current energy and industrial policy trajectory and decides in the late forecast horizon to enable resource exploitation in the Ring of Fire	Global economic uncertainty dampens upward trends on mineral demand; Ontario faces competition from other jurisdictions for mine siting and development
Electricity Intensity	Meeting 2050 Targets	Stated Objectives	BAU

Forecast Mineral Production Level	High	BAU	Low
Ring of Fire Infrastructure Investment Timing	Early	Late	None
Project Probabilities	High	BAU	Low

The PowerBI results presentation dashboard allows IESO to run sensitivities on the following items for each scenario:

- Assign a multiplier for known projects in the short and long term as a proxy for changes to project characteristics, such as probability and projected demand.
- Forecast mineral production level by mineral type.
- Year in which mining production in the Ring of Fire begins (the sensitivity analysis allows for expediting or delaying the introduction of mining production in the Ring of Fire by up to five years).
- Electricity intensity for known and unknown mining projects.

3.4 Modelling Steps

Based on the selected forecast methods, data acquisition steps, and scenario definitions, PG can produce alternate future scenarios of the mining sector across the entirety of Northern Ontario spanning from 2021 to 2050. This includes the known current and future projects, as well as estimates of electricity demand requirements and the number of unknown future projects. This section describes the steps taken to produce the Ontario-wide mining forecast from 2021 to 2050 and how the model architecture was set up to produce these results.

3.4.1 Model Architecture

The first step in creating the model was to set up the model architecture in a way that the downstream results could easily be presented and such that the model integrated easily with the assumptions described in Section 3.3. This includes making sure regions align with those outlined in the IESO's mining forecast and setting up the different segments of the model so that they represent all the different types of mining projects within Ontario. Exhibit 6 below displays all the regions analysed within this model as well as their IESO Zone.

Exhibit 10 – Geographic Resolution

IESO Zone	Region
Northeast Ontario	• East Lake Superior (ELS) • Northeast of Sudbury (NEoS) • Sudbury/Algoma
Northwest Ontario	• Greenstone/Thunder Bay (TB) • Dryden • Pickle Lake • Marathon • West of Thunder Bay (WoTB) • Remote Communities

Individual mining projects, as well as future unknown mining projects (further explained in Section 3.4.3 below), were represented as segments within this model. Each segment has several different attributes that describes all the relevant characteristics of the project and allow for results to be easily rolled up into different categories for visualization purposes. These attributes include whether the project is a mine or smelter, whether the project is known or unknown, which type of mineral is being mined and whether the project is to operate within the Ring of Fire. These attributes can be viewed in Exhibit 7 below.

Exhibit 11 – Project Attributes

Mine Name	Mine/Smelter	Known/Unknown	Mineral Type[13]	Ring of Fire (Y/N)
Each segment is defined by the name of the mining project(s) that it	• Mine • Smelter	• Known • Unknown	• Gold • Base Metal	• Yes • No

[13] Mineral Type was limited to gold, base metal, and base metal (Ring of Fire) to align with the forecast methods outlined in Section 3.1. The Smelter category was added to differentiate smelters from mines in the results.

Mine Name	Mine/Smelter	Known/Unknown	Mineral Type[13]	Ring of Fire (Y/N)
represents, for example: Bell Creek Mine			• Base Metal (Ring of Fire) • Smelter	

The analysis model is capable of differentiating energy demand by end use and has been set up to do so. However, the current end use breakdown simply contains placeholder information that can be replaced in the future if concrete metered data from the IESO service territory emerges over time that will allow differentiating mine energy demand by end use.

3.4.2 Known Projects

After setting up the model architecture, the next step is to generate input values for each of the segments to reproduce the base year (2021) demand from IESO's existing mining forecast. This is achieved by using the information from all the known mining projects in the IESO's mining forecast and attributing that data to the corresponding segments in our model. This includes matching the electricity demand as well as the project likelihoods and probability factors used by the IESO. The only difference in Known Projects between the PG model and IESO's is the addition of The Great Bear Project, the inclusion of the Crawford Nickel-Cobalt Sulphide project in the Reference Case & Ring of Fire (Medium) Scenario and the shifting of the known Ring of Fire project timelines, as described in Section 3.3.3. Since these projects do not start until after 2021, the base year peak demand seen in our model matches the peak demand seen in 2021 in the IESO's model at 596.9 MW across the entire province.

As the IESO mining model only extends until 2041, information on the Known Projects had to be estimated until 2050 for this new iteration of the model. There are several projects from the IESO model that are not expected to become operational until the 2030s that would likely continue operating beyond the 2041 limit presented in that model. The average operating lifespan of a mine in Canada is estimated to be 15 to 20 years,[14] and given the propensity of mines to extend or expand their operations, it was decided to use 20 years as the rule of thumb for mine lifetimes, regardless of mineral type. As such, any mine that is expected to be less than 20 years old in 2041 was extended so that it would reach the 20-year lifetime after 2041[15].

IESO's forecast also includes two smelters, the Crawford Smelter and the Algoma Steel Electric Arc Furnace (EAF) Smelter. Since the Crawford Smelter is tied to the Crawford Nickel-Cobalt Sulphide project, the lifetime and project likelihood were aligned with those used for the mine. The Algoma Steel EAF did not have an associated mine and no lifetime stated so an estimate of 40 years was used for this case, in accordance with the typical lifetimes of similar plants.[16] The Algoma Steel EAF Smelter was included in all three scenarios whereas the Crawford Smelter was only included in the Active Electrification & High Production (High) Scenario. As the aim of the forecast focused mainly on mining projects, the two known smelters from the IESO's forecast were the only smelters that were included within the analysis.

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[14] https://ontarionature.org/wp-content/uploads/2017/10/mining-in-ontario-web.pdf

[15] The Moneta Project and the Crawford Nickel-Cobalt Sulphide Project are the exception to this approach as they were explicitly said to have lifetimes longer than 20 years.

[16] https://www.jstor.org/stable/pdf/resrep15596.9.pdf

3.4.3 Unknown Projects

The number of Known Projects decreases later in the forecast horizon because there is less certainty projects will materialize and less information available on future projects. The total number of projects and electricity demand will not necessarily decrease in the future, however, as there are numerous currently Unknown Projects that could emerge in the future.

Where for the Known Projects, individual mines were used as model segments, for the Unknown Projects, unknown mines segments were categorized by region and mineral type. This way, a general estimate could be made given previous knowledge of similar known mines in the same region and mineral type. Because of this, one unknown mines segment could represent multiple future mines, whereas all known mines segments just represent one individual mining project. Exhibit 8 below outlines the unknown mines segments.

Exhibit 12 – Unknown Projects Segments

Gold Mines	Base Metal (BM) Mines	Ring of Fire Base Metal (BM) Mines
• Future Gold Mines – ELS • Future Gold Mines – NEoS • Future Gold Mines – Sudbury/Algoma • Future Gold Mines – Greenstone/TB • Future Gold Mines – Dryden • Future Gold Mines – Pickle Lake • Future Gold Mines – Marathon • Future Gold Mines – WoTB	• Future BM Mines – ELS • Future BM Mines – NEoS • Future BM Mines – Sudbury/Algoma • Future BM Mines – Greenstone/TB • Future BM Mines – Dryden • Future BM Mines – Pickle Lake • Future BM Mines – Marathon • Future BM Mines – WoTB	• Future Ring of Fire BM Mine – Remote Communities

The total unknown electricity demand was calculated by subtracting the known mining demand from the estimated total mining demand forecast described in Section 3.3. Since the segments representing the known mining projects were also categorized by region and mineral type, information on the proportions of known mines by region and mineral type was used to calculate the unknown mining demand for each of the segments outlined above in Exhibit 8. The proportion of mining demand by region for each mineral type was calculated at the peak of known mining demand, which was 2026 for gold mines and 2030 for base metal mines. All Ring of Fire Base Metal mines reside in one region (Remote Communities) so this step was not necessary for that mineral type.

An example of this calculation is provided below for the Future Gold Mines in the East Lake Superior (ELS) region in 2030.

$$MW_{known\ gold,2030} = 714.5MW, \qquad MW_{gold\ forecast,2030} = 816.2MW, \qquad \%_{gold,ELS,peak} = 8.52\%$$

$$MW_{Future\ Gold,ELS,2030} = \%_{gold,ELS,peak} \times MW_{unknown\ gold,2030}$$

$$MW_{Future\ Gold,ELS,2030} = 8.52\%(816.2MW - 714.5MW) = 8.67MW$$

Where,

$MW_{known\ gold,2030}$ is the known gold mining demand across all regions in 2030,

$MW_{gold\ forecast,2030}$ is the total forecasted gold mining demand across all regions in 2030 and

$\%_{gold,ELS,peak}$ is the proportion of the total gold mining demand attributed to the ELS region in the peak year of known mine production (2026 for gold mines).

After calculating the estimated unknown mining electricity demand, the number of mines that make up the demand for each of the "Future Mines" segments was calculated. This was achieved by dividing the unknown demand by the typical demand per mine calculated for the known mining projects of similar mineral type and region. This was also done using the years in which the demand from known mining projects was at its peak for each mineral type (2026 for gold mines and 2030 for base metal mines). Since there is no information on the Ring of Fire prior to the introduction of the future mines, as Known Projects become operational in the same year as the unknown ones, the demand per mine for base metals across the entire province was used to determine the number of mines in the Ring of Fire. Once calculated, all unknown mine totals were rounded up to the nearest whole mine.

The example from above for Future Gold Mines in the East Lake Superior (ELS) region in 2030 is continued below to illustrate how the number of unknown mines was calculated.

$$MW_{known\ gold,ELS,peak} = 60.9MW, \qquad Mines_{known\ gold,ELS,peak} = 4\ mines,$$
$$MW_{Future\ Gold,ELS,2030} = 8.67MW$$

$$Mines_{Future\ Gold,ELS,2030} = \frac{MW_{Future\ Gold,ELS,2030}}{(Demand\ per\ Mine)_{known\ gold,ELS,peak}}$$

$$Mines_{Future\ Gold,ELS,2030} = MW_{Future\ Gold,ELS,2030}\frac{Mines_{known\ gold,ELS,peak}}{MW_{known\ gold,ELS,peak}}$$

$$Mines_{Future\ Gold,ELS,2030} = 8.67MW\frac{4\ mines}{60.9MW} = 0.57\ mines = 1\ mine$$ [17]

Where,

$Mines_{Future\ Gold,ELS,2030}$ is the unknown gold mining demand in the ELS region in 2030,

$MW_{known\ gold,ELS,peak}$ is the known gold mining demand in the ELS regions in peak year of known mine production (2026 for gold mines) and

$Mines_{known\ gold,ELS,peak}$ is the number of known gold mining projects in the ELS regions in peak year of known mine production (2026 for gold mines).

PG used the approach outlined above to calculate the estimated mining demand and number of mining projects for all the unknown segments displayed in Exhibit 8.

[17] All values from this calculation are rounded up to the nearest whole mine.

3.4.4 Finalizing Inputs and Producing Results

Once the electricity demand for all segments within the model was calculated, the electricity intensity factors and a peak factor were applied before the inputs were finalized for model execution. With the increase in electrification in the mining sector, the electricity demand is expected to increase as well. To model this behavior, the electricity intensity factors estimated in Section 3.3.1, for each of the three scenarios, were multiplied with the demand calculated in Sections 3.4.2 and 3.4.3.

Additionally, the PG Navigator Energy and Emissions Simulation Engine (Navigator) is designed to produce annual consumption outputs and then calculate peak hourly demand or 8760 demand profiles given a peak factor or 8760 load profile, respectively. Therefore, a peak factor, which was calculated from the generic load shape provided by IESO,[18] was applied to the demand inputs after the electricity intensity factor had been applied to transform the inputs to reflect annual consumption.

Finalized values were inputted into the model to produce the following three results categories:

Consumption and Peak Demand Comparison

This model run produced outputs in terms of annual consumption and peak hourly demand for each of the segments analysed within the model. This was done for each of the three scenarios. The annual consumption was calculated using the inputs discussed within this section and the peak hourly demand was calculated by dividing by the peak factor previously applied. The results of this model run were imported into a PowerBI dashboard to allow for visualization by region and mineral type. This dashboard includes several different sensitivity parameters to allow users to adjust the end results given different circumstances. Since the results are aggregated, a coincidence factor of 0.9 was applied on the outputted peak demand, as was done in the IESO's forecast.

Individual Peak Demand Results by Mining Project

Using the outputs from the previous set of results, the peak demand for each individual mining project could be compiled and presented by scenario. Since the demand is no longer presented in aggregate, the coincidence factor of 0.9 was not applied to these results to get a more accurate view of each individual project's demand. These results were also presented with the applicable mining load profile so that 8760 demand profiles can be generated for any given project if desired.

Aggregate 8760 Demand Profiles by Region

This set of results produced the 8760 load profiles for four categories for each of the three scenarios: all of Northern Ontario, Northwestern Ontario, Northeastern Ontario and just the Ring of Fire. In the same way as for the previous results, the inputs were used to produce outputs in terms of annual consumption, to which the mining load profile provided by the IESO was applied. For typical load shapes that show significant differences between weekend and weekday energy consumption, the load profile is pre-processed to correctly align with the weekdays for each year within the forecast period. Since the load shape for mining was found to be generally flat across the entire profile, this step was skipped.[19] As the peak demand results are presented in aggregate, the coincidence factor of 0.9 was applied.

[18] The peak factor is calculated by taking the inverse of the maximum hour from the nondimensionalized load profile.
[19] Deviations from the mean energy consumption values per day were between -1.4% and 3.0% which suggests that consumption does not strongly depend on the day of the week.

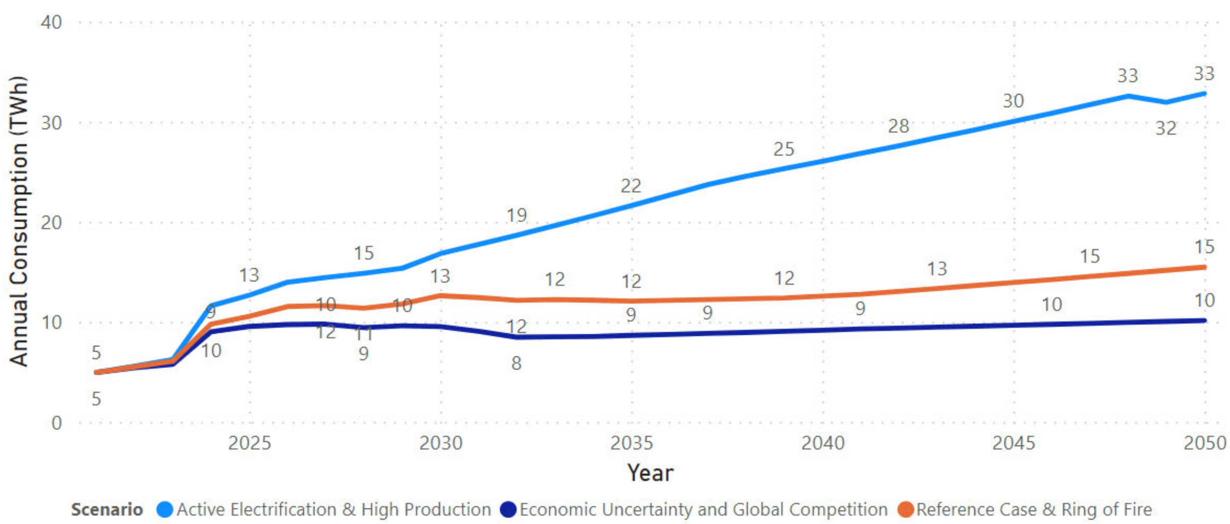
3.5 Mining Forecast Results

This section displays the results of the Ontario-wide mining forecast from 2021 to 2050 described in the sections above. The annual consumption and the peak demand for each of the three scenarios outlined in Exhibit 5 are presented in Section 3.5.1 and 3.5.2, respectively. The results of this model are compared to those presented in IESO's 2022 Annual Planning Outlook (APO) in Section 3.5.3. Lastly, any uncertainties or research gaps within the model are highlighted in Section 3.5.4.

3.5.1 Annual Consumption

The annual forecasted consumption for the mining sector in Ontario can be viewed in Exhibit 9.

Exhibit 13 – Annual Consumption by Scenario



The Active Electrification & High Production scenario is expected to have the largest annual consumption throughout the forecast period, reaching an estimated annual consumption of about 33 TWh in 2050. This is largely due to the more aggressive mineral demand forecasts used within the scenario, resulting in more unknown mining projects, the inclusion of two major smelting projects, and an applied electricity intensity factor of 1.66 (which reflects that 100% of mining projects are expected to operate at net zero emissions by 2050). These factors, along with the earlier introduction of mining production in the Ring of Fire (by 2030), result in the almost continuous upward trajectory of annual consumption seen in the forecast and an increase in annual consumption between 2021 and 2050 of over 550%.

The Reference Case & Ring of Fire scenario sees a much smaller increase in annual consumption, with an expected annual consumption of approximately 15 TWh by 2050. While this corresponds to an increase in consumption of roughly 210% between 2021 and 2050, the increase in consumption of approximately 23% between 2030 (during which the peak consumption for known mining projects in this scenario occurs) and 2050 shows that the increase is driven much less by the introduction of new, currently unknown projects. The Reference Case & Ring of Fire scenario is dictated largely by the consumption from known projects, with only slight increases resulting from the expected increases in employment in the sector, the delayed introduction of production in the Ring of Fire (in 2040) and the projection that 40% of mining projects will reach net zero emissions by 2050.

Lastly, the Economic Uncertainty and Global Competition scenario has the lowest expected annual consumption in 2050 with approximately 10 TWh. Again, while the expected increase in consumption between 2021 and 2050 is roughly 105%, there is a very small increase between 2027 (the peak year for consumption from known projects for this scenario) and 2050 of about 4%. This suggests that while there is expected to be an initial increase in annual consumption due to known projects that are anticipated to begin production in the near future, this trend will not continue and the number of new mines and their annual consumption will begin to decrease after 2027, before slightly increasing again from 2032 onwards. Additionally, the lack of mining production in the Ring of Fire and the lower electricity intensity increases (only 20% of mines are assumed to reach net zero by 2050) result in this scenario not seeing as much of an increase in consumption in the later years of the forecast when compared to the other two scenarios.

Exhibits 10, 11 and 12 illustrate the annual consumption for each of the three scenarios individually. They also break the consumption down by IESO zone to describe the annual consumption for mining projects in the North East and North West zones of Ontario. In all three scenarios, the majority of consumption comes from the North East zone, in part, due to large projects such as the Algoma Steel Electric Arc EAF Smelter, the Crawford Smelter and the Crawford Nickel-Cobalt Sulphide mine residing in this zone.[20]

Exhibit 14 – Annual Consumption: Active Electrification & High Production Scenario

[20] The large increase in consumption seen between 2023 and 2024 is due to the introduction of these projects in 2024.

Exhibit 15 – Annual Consumption: Reference Case & Ring of Fire Scenario

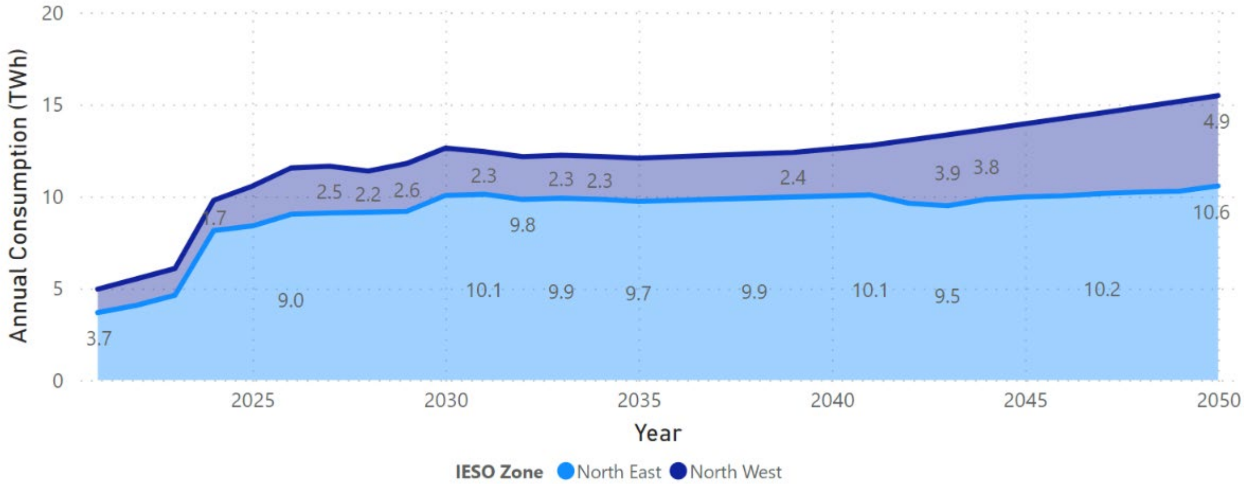
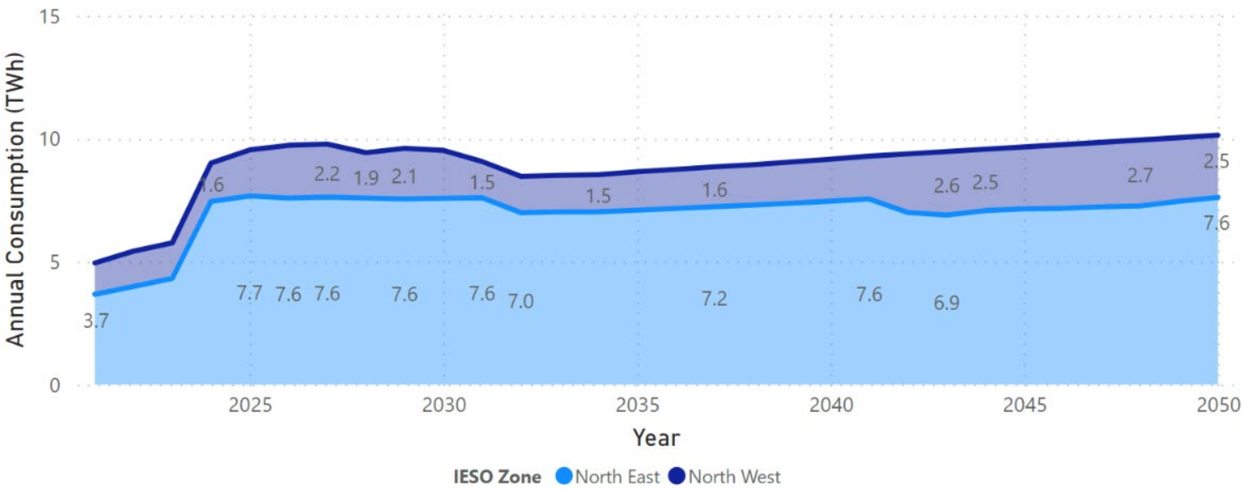


Exhibit 16 – Annual Consumption: Economic Uncertainty and Global Competition Scenario

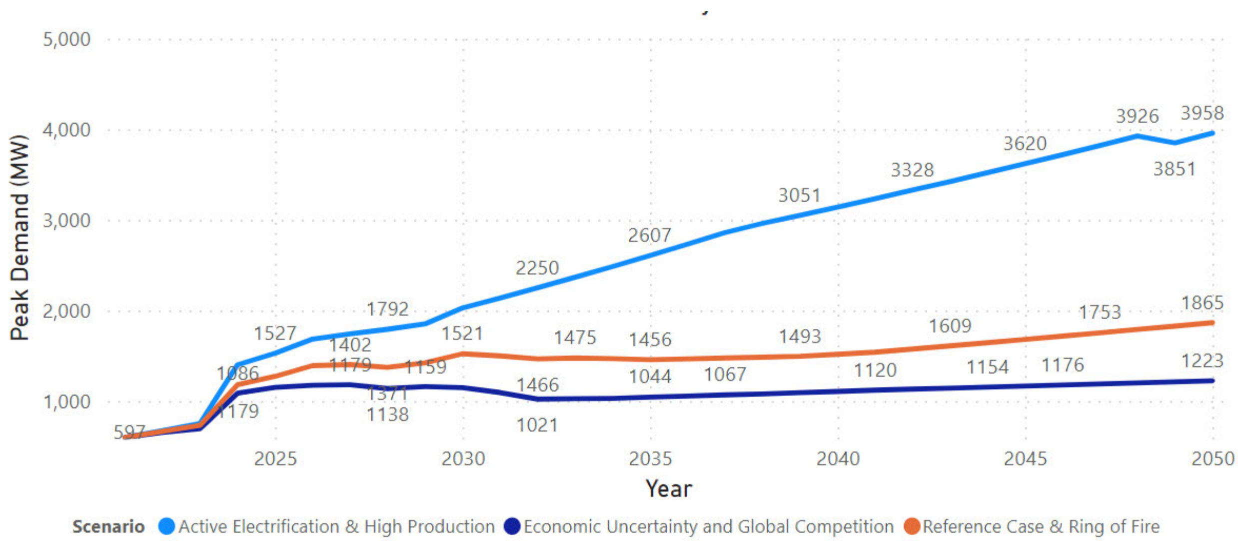


The Active Electrification & High Production and the Reference Case & Ring of Fire scenarios see an increase in consumption in the North West zone in the later years of the forecast with the introduction of mining production in the Ring of Fire. Making up for 3.3 TWh in the Active Electrification & High Production scenario and 1.32 TWh in the Reference Case & Ring of Fire scenario, projects in the Ring of Fire account for roughly 10% and 8.5% of the annual consumption by 2050 for their scenarios, respectively.

3.5.2 Peak Demand

The peak demand forecasted for the mining sector in Ontario can be viewed in Exhibit 13.

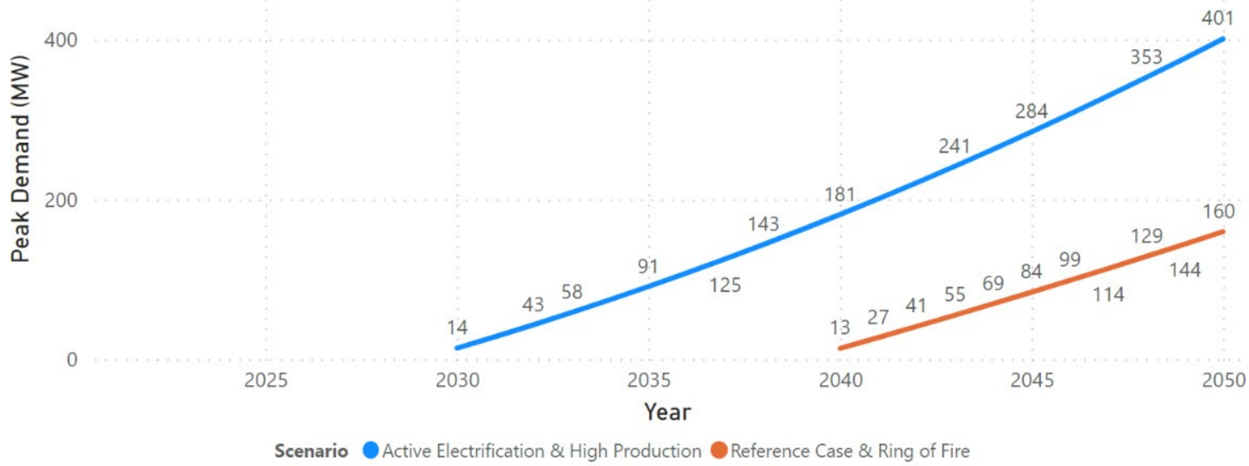
Exhibit 17 – Peak Demand by Scenario



Since the annual consumption was calculated by applying a constant peak factor to the peak demand (and the peak demand can be calculated by applying the inverse of said constant peak factor to the annual consumption), the shape of the peak demand forecast is identical to the shape of the annual consumption forecast. Exhibit 13 illustrates that the expected peak demand in 2050 is approximately 4,000 MW for the Active Electrification & High Production scenario, approximately 1,900 MW for the Reference Case & Ring of Fire scenario and approximately 1,200 MW for the Economic Uncertainty and Global Competition scenario.

For the Ring of Fire, the peak demand for the Active Electrification & High Production and the Reference Case & Ring of Fire scenarios in 2050 is estimated to be approximately 400 MW and 160 MW, respectively, as seen in Exhibit 14. The effect of the higher electricity intensity assumed for the Active Electrification & High Production scenario, with a projected 100% of mines reaching net zero by 2050, can also be viewed in how the forecast lines curve upwards at different rates. Combined with the 10-year head start in mining production in the region, this results in a difference of roughly two and a half times between the two scenarios. With the potential resource basins in the Ring of Fire expected to be large, this illustrates that concrete information on the start dates of the infrastructure and mining operations in that region can be a significant factor for forecasting the overall mining demand across the province.

Exhibit 18 – Ring of Fire Peak Demand by Scenario



Exhibits 15, 16 and 17 display the peak demand forecasts for each of the three scenarios individually, illustrating the breakdown by the North East and North West IESO zones. The use of the constant peak factor to convert forecast values between annual consumption and peak demand means that the characteristics of the peak demand forecast will match those displayed for annual consumption in Exhibits 10, 11 and 12.

Exhibit 19 – Peak Demand: Active Electrification & High Production Scenario

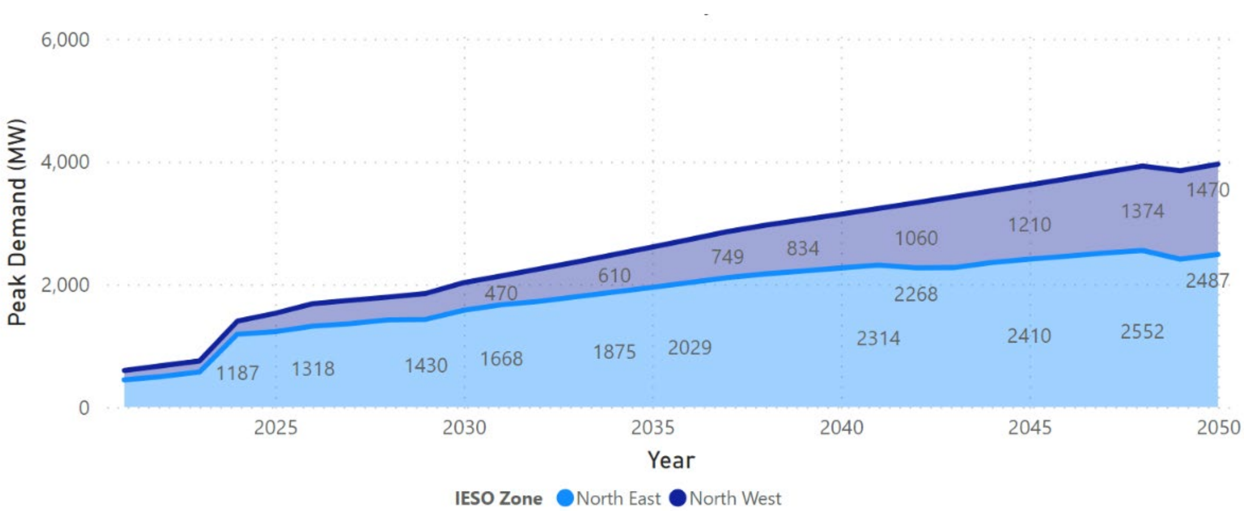


Exhibit 20 – Peak Demand: Reference Case & Ring of Fire Scenario

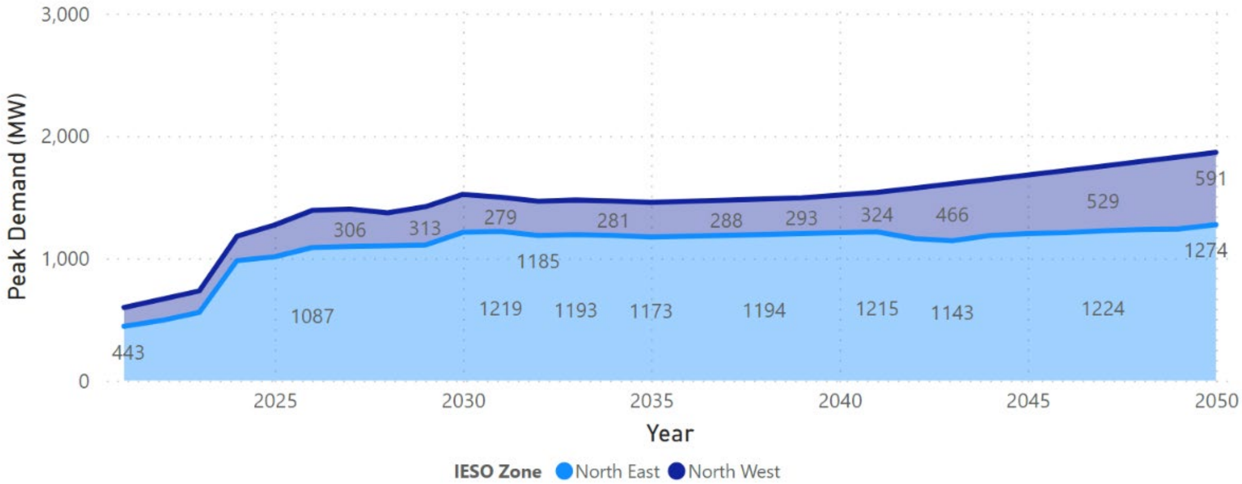
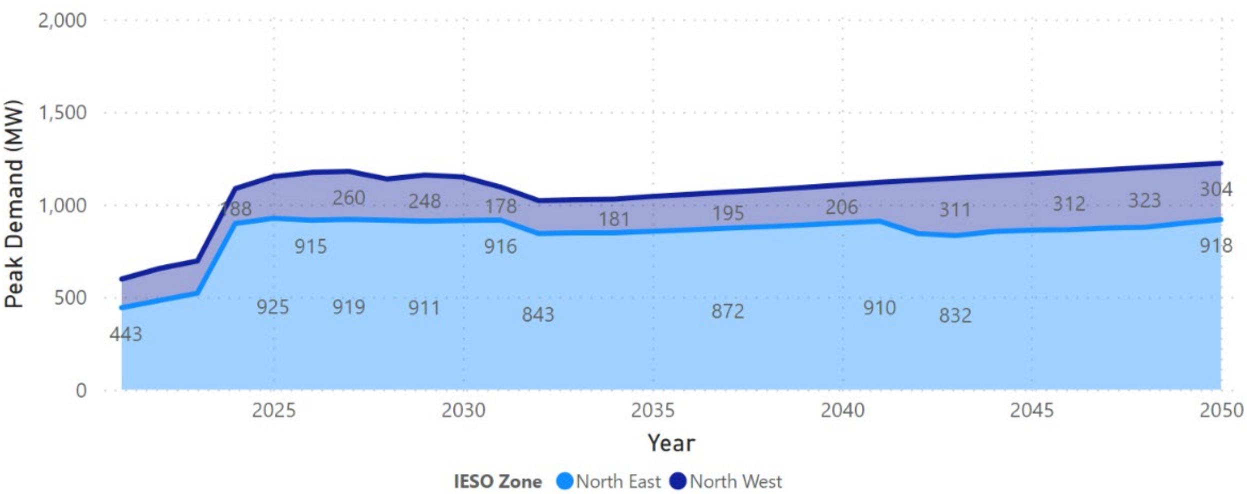


Exhibit 21 – Peak Demand: Economic Uncertainty and Global Competition Scenario



In addition to peak demand values, the 8760 load profiles for all of Ontario, each of the IESO zones (North East and North West) and for the Ring of Fire were calculated and are provided in supplementary Excel workbooks. The mining load shape provided by the IESO was used to calculate the 8760 load profiles, along with the annual consumption values for each of the regions. Given that mines tend to run at full capacity as much as they can and the flattening effect this has on the load shapes, the average demand for any given mine can also be calculated to be approximately 85% of the peak demand.

3.5.3 Comparison to IESO's Existing Forecasts

The results of this forecast can be compared to the results of the forecast from the IESO's 2022 Annual Planning Outlook (APO). Before a direct comparison is made, some differences between the two forecasts should be noted:

- PG's forecast includes unknown projects, which are not included in the 2022 APO. This includes additional unknown projects in the Ring of Fire. The IESO's forecast only includes known projects, for which information and certainty begins to decrease after 5+ years into the forecast period. The inclusion of unknown projects in PG's forecast increases the overall demand (specifically in later years of the forecast) at varying degrees depending on the scenario. This is most apparent in the Active Electrification & High Production scenario, where the large number of unknown projects due to the increase in demand for gold and base metals drive the continuous upward trends in electricity consumption and peak demand. The other two scenarios are less influenced by unknown projects, especially before 2041, as the production forecasts are more modest, so the differences between them and the IESO's 2022 APO forecast are dictated in more equal proportions by the factors listed below.

- PG's forecast includes increased electricity intensity factors to simulate mining projects transitioning to net zero technologies. This also increases the overall demand forecasted (specifically in later years of the forecast) at varying degrees depending on the scenario.
- Based on information provided by the IESO, it is assumed that the 2022 APO mining sector forecast only includes the Crawford Smelter, since it is associated with the Crawford Nickel-Cobalt Sulphide mine. The Algoma Steel EAF Smelter is assumed to be included in the primary metals forecast, and thus not accounted for in the mining forecast portion of the 2022 APO.
- PG's forecast has also included updated information and new mines that were not included in the 2022 APO forecast. An example of this is the inclusion of the Great Bear Project mine in the Dryden region.

Given these differences, when comparing the PG mining model and the 2022 APO results, the 2022 APO mining forecast generally fits between the Reference Case & Ring of Fire and the Economic Uncertainty and Global Competition scenarios. The APO forecast starts above the Reference Case & Ring of Fire scenario in 2024[21], before intersecting with it between 2027 and 2028, at which point it remains between the two PG scenarios. The APO forecast peaks in 2026 and begins to decline after that, all the way until 2041. The APO's exclusion of unknown projects likely is the main reason why the APO forecast and the Reference Case & Ring of Fire scenario slowly diverge from each other.

3.5.4 Uncertainties and Research Opportunities

The mining forecast incorporates the latest information made available to PG, including data that had been sourced up until January 2023. As new data evolves over time, the forecast will need to be updated in order to accurately capture the direction of the mining sector in Ontario. Specific aspects of uncertainty within the model are highlighted below:

- Load Shape – We examined existing demand, conducted desktop research and stakeholder interviews but this still leaves uncertainty about what load shapes for mining end uses will look like as mines transition towards electricity as a power source. Future onsite measurements may help reduce such uncertainty as projects transition towards 100% net zero.
- Electricity Intensity – We conducted desktop research, examined data from individual projects, and gathered advice from industry experts, but this does not replace onsite data on end use electricity intensity as mines actually transition towards 100% net zero, specifically as questions

[21] This is assumed to be due to the inclusion of the Crawford Smelter in the 2022 APO forecast and not in PG's Reference Case & Ring of Fire scenario.

around self-generation remain. The trajectory towards net zero also depends on government policy and shareholder demand for such a transition and can be subject to change in the future.

- Production levels – We used S&P Global employment forecasts and third-party research on demand for minerals during the energy transition but numerous policy and macroeconomic factors that continuously evolve over time will determine future mining investments in Ontario.

Additionally, there are other factors (e.g., social license to develop and operate projects, relationships with local communities) outside the ones modelled here that may impact mining project development and lifecycles in Ontario – by necessity a model is a simplification of reality and should be viewed as a structured framework for thinking about what the future might look like rather than an immutable prediction of what will occur.

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Appendix A Mining Sector Interview Guide

Introduction

The IESO is seeking to validate and enhance its long-term electricity load forecast for the mining sector to prepare for an expected increase in demand in this market due to ongoing mine expansion and electrification efforts. The IESO has hired Posterity Group to review and identify opportunities to update these forecast efforts.

In support of this work, we would like to schedule a time to call you and discuss various factors that are expected to affect mining electrical load. Interview questions will be provided in advance and the interview is expected to take no longer than 45 minutes.

Please note that information collected during this call may be publicly disclosed for the purposes of:

i) Articulating the assumptions that inform the final load forecast.

ii) Providing additional detail on the load forecast in public regulatory forums as required to support any relevant Leave to Construct proceedings before the Ontario Energy Board.

For any public disclosures, we will not attribute information collected to individual interviewees and will disclose aggregate information only.

If you would like to speak to an IESO representative about this study, please contact:
Tom Aagaard, *Tom.Aagaard@ieso.ca*.

Please see below for the interview topics and questions that we expect to cover in order to gather your input. While these questions are comprehensive, our interview approach allows us to focus on items that that are in your particular areas of expertise.

Response Segmentation

- What is your key area of focus within your organization (e.g., energy, technology, innovation, government relations)?

Economic Condition Assumptions Influencing Mining Load Growth

- What key (global) macroeconomic factors do you expect will influence mining production output in Ontario over the next 5, 10, and 20 years?
- How do you expect these factors will behave over time and under different assumptions about resource policy (do you see any forks in the road)?

Constraints Influencing Facility Development/Electrification Timelines

- Other than existing grid capacity constraints, what technical or policy considerations exist that could slow down or prevent expanded mining production or electrification of mining operations?
- To what extent and when do you expect these considerations to apply under different assumptions about resource policy (do you see any forks in the road)?

End Use Electrification Drivers

- What mining and mineral processing energy end uses (e.g., material movement, process heating, ventilation) are expected to be electrified and what considerations will drive these electrification decisions?
- Do any factors exist that would delay or prevent electrification of mining/mineral processing end uses (how strong are these expected to be over time)?
- To what extent does the availability of sufficient electric grid power drive end use electrification decisions when compared with other factors (e.g., end use technology maturity, cost, change management)?

Typical End Use and/or Mine Site Load Profiles

- How do you expect overall mining and mineral processing end use load profiles will change over time from the currently observed patterns?
- How do you expect technology innovation will shape the efficiency of mining and mineral processing electricity end uses over time?
- To what extent and under what circumstances will self-generation meet mining and mineral processing electricity demand over time?

Interview Close

Additional requests:

- Load profile data, if available
- Other relevant studies or data

THANK YOU FOR YOUR TIME

[redacted]

[redacted]

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Connecting Today.
Powering Tomorrow.

PROJECT CATEGORIZATION

The Board's filing guidelines require that projects be categorized to distinguish between a project that is a "must-do", which is beyond the control of the applicant ("non-discretionary"), from a project that is at the discretion of the applicant ("discretionary"). Non-discretionary projects may be triggered or determined by such things as:

a) mandatory requirement to satisfy reliability standards set by authorities including NPCC/NERC or by 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, the Project is considered non-discretionary. The Waasigan Project is being undertaken to comply with a mandatory requirement to satisfy obligations specified by the OEB in Hydro One's transmission licence and as directed by the Provincial government's OIC, as authority described in **Exhibit B, Tab 3, Schedule 1**.

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COST BENEFIT ANALYSIS AND OPTIONS

Based on the OIC issued by the Minister of Energy and the IESO's analysis, as provided and outlined in the Need Evidence at **Exhibit B, Tab 3, Schedule 1**, there are no non-wires alternatives to the Phase 1 and/or Phase 2 scopes of work for which Hydro One is seeking OEB leave to construct approval in this Application.

ALTERNATIVES

1.0 ROUTE ALTERNATIVES

Alternative routes for the transmission line were identified as part of the Project's development work. The alternative routes considered were:

1. between Thunder Bay and Atikokan;
2. in the Atikokan area;
3. north of Atikokan to Wabigoon Lake; and
4. between Wabigoon Lake and Dryden.

In January 2023 Hydro One publicly released a preliminary preferred Project route for review and comment. During this route development and evaluation period a community group made up of members of the Kaministiquia community expressed concerns about a portion of that line route. The Kaministiquia community requested Hydro One evaluate a new alternative route for a section of the Phase 1, located between Shuniah to Atikokan. Hydro One subsequently undertook and completed a detailed review and analysis of the alternative proposed by Kaministiquia community members. All alternative route assessments undertaken by Hydro One determined that the Project's preliminary preferred route, as included in this Application, best balances Indigenous culture, values and land use, natural environment, socio-economic environment, and technical and cost considerations.

2.0 TRANSMISSION LINE ALTERNATIVES

Conductor Size Alternative Analysis

Hydro One undertook an analysis of the conductor size alternatives that would, a) meet the supply forecast needs in the west of Thunder Bay area and, b) would also be the optimal conductor size and rating, based on the expected load scenario in terms of line losses. The conductor alternatives evaluated were:

1. Alternative 1 - ACSR 795 kcmil conductor
2. Alternative 2 - ACSR 997 kcmil conductor
3. Alternative 3 - ACSR 1192 kcmil conductor
4. Alternative 4 - ACSR 1443 kcmil conductor

Hydro One conducted an NPV analysis using *Alternative 1* as the base conductor, and then compared the other alternatives to *Alternative 1* evaluating incremental capital cost and line loss reduction, to determine which conductor alternative provided the best incremental NPV result. This ensured that the conductor chosen would be prudent to the rate payer, in terms of line loss considerations.

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. Consistent with Hydro One's Transmission Line Loss Guideline[1], Hydro One's screening tool[2] was used to determine which alternative was optimal. The results and analysis are summarized below in Table 1.

[1] EB-2021-0110 – Exhibit B, Tab 2, Schedule 1, Attachment 4, Appendix A – August 5, 2021.
[2] Used for line loss evaluation in the prior EB-2022-0140 Hydro One s.92 Application approved by the OEB.

Table 1 - Analysis of Conductor Alternatives

	Incremental NPV			
	Alt # 1 795 kcmil	**Alt # 2 997 kcmil**	**Alt # 3 1192 kcmil**	**Alt # 4 1443 kcmil**
Incremental Capital Cost[3] ($M's)	0.0	5.0	9.5	12.5
Incremental OM&A ($M's)	0.0	0.0	0.0	0.0
Annual Losses (MWh)	11,961.4	9,751.1	8,413.8	6,942.8

While *Alternative 1* is the lowest cost based on incremental capital costs, transmission line losses were also deemed to be material. Given the line loss differential between the alternatives, Hydro One conducted a detailed 50-year NPV analysis, using a 5.65% discount rate for the incremental costs/losses of the alternatives, to evaluate which conductor alternative provided the best incremental NPV result. An incremental NPV sensitivity analysis was also done using varying values for the price of energy.

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

[3] The incremental capital cost for each alternative with respect to Alternative 1 (i.e. by using the 795 kcmil conductor at the base scenario).

Table 2 - Incremental NPV of Alternatives

	Alt # 1 795 kcmil	**Alt # 2 997 kcmil**	**Alt # 3 1192 kcmil**	**Alt # 4 1443 kcmil**
Incremental Capital Cost ($M's)	0.0	5.0	9.5	12.5
	Incremental Net Present Value ($M)			
Energy Price ($/MWh)	**Alt # 1 795 kcmil**	**Alt # 2 997 kcmil**	**Alt # 3 1192 kcmil**	**Alt # 4 1443 kcmil**
$47.30[4]	0.0	-1.7	-3.9	-4.8
$80.00[5]	0.0	0.1	-1.1	-0.8
$120.00[6]	0.0	2.3	2.4	4.1

The results show that *Alternative 1* has the lowest incremental NPV based on capital costs alone, and *Alternative 1* also has the lowest incremental NPV if losses are included at an HOEP of $47.30/MWh. The results of the incremental NPV energy price sensitivity analysis provided above outlines that for the incremental costs of the *Alternative 2* to be at least economically neutral to the rate payer, the average annual increase to HOEP would have to approximately $30/MWh greater than the HOEP of $47.30/MWh.

Based on the analysis, *Alternative 1* is selected as the preferred and recommended alternative.

---

[4] Losses calculated based on 2022 average HOEP of 47.3/MWh forecast (per the IESO's 2022 Planning Outlook Report). Hydro One does not have any basis to deviate from the HOEP and it is the only current settlement mechanism to recover transmission line loss costs.
[5] At $78/MWh *Alternative 1* and *Alternative 2* intersect.
[6] $120/MWh was a price level requested for analysis by intervenors in past Hydro One s.92 filings.

QUANTITATIVE AND QUALITATIVE BENEFITS OF THE PROJECT

QUANTITATIVE BENEFITS

Detailed system benefits expected to be delivered by the Project are predominantly documented in this Application's Project need evidence, which is found at **Exhibit B, Tab 3, Schedule 1**, including information regarding quantitative benefits, as outlined in the IESO Report Titled, *Waasigan Transmission Line Project: Need, Alternatives, and Recommendation Report* at **Exhibit B, Tab 3, Schedule 1, Attachment 9**.

Hydro One conducted economic analysis to investigate the quantitative impacts with respect to the size of the conductor that will be used for the Project and its anticipated effects with regards to transmission line losses. The NPV of the energy price sensitivity analysis confirms that the 795 kcmil conductor is the most appropriate and beneficial conductor size to meet the needs of the Project. The assessment of the benefits of alternative conductor sizes and the results thereof are included in in **Exhibit B, Tab 5, Schedule 1,** and the economic impacts of the Project's Phase 1 and Phase 2 components (preferred alternatives) that Hydro One is seeking approval for are presented in **Exhibit B, Tab 9, Schedule 1**.

QUALITATIVE BENEFITS

The Waasigan Project is anticipated to bring economic benefits to the province, as supported by the Government and the IESO and outlined in the Project's need evidence at **Exhibit B, Tab 3, Schedule 1**. In that evidence, both the Government and the IESO expect the Project to deliver further macro-economic benefit to the province via the increased electrification the Project will ultimately result in. As outlined in the 2017 LTEP[1], the need for the Waasigan Project[2], "is needed to support growth and maintain a reliable electricity supply to areas west of Atikokan"[3]. The new transmission line facilities

[1] 2017 LTEP - Delivering Fairness and Choice (ontario.ca)
[2] Then known as the 'Northwest Bulk Transmission Line Project'.
[3] 2017 LTEP - Delivering Fairness and Choice (ontario.ca)

will help to meet the anticipated increase in the area's overall demand as electrification of the economy increases. The increased electrical supply, which the Waasigan Project will address, is driven primarily by anticipated future growth in the mining and forestry industries and serve customers growing needs with clean and renewable sources, along with enhancing the potential for development and connection of renewable energy facilities via this additional transmission path.

The Project will ensure load in the west of Thunder Bay region can be adequately supplied post December 2025 (Phase 1) and December 2027 (Phase 2). The Project's Phase 1 and Phase 2 elements will also improve the reliability and quality of energy supply by providing an additional transmission path for system generation to be delivered to the region. Also, as recommended by the IESO, Phase 2 will be routed near Dinorwic Junction to facilitate potential future system reinforcements north of Dryden[4]**.**

The Project will bring both short term and long-term employment, training, and business opportunities to the region. This includes opportunities for both Indigenous and non-Indigenous communities and businesses to benefit from the construction, operation, and maintenance of the Project. Hydro One is collaborating with Indigenous communities in the region to understand their interests and aspirations in the future of Ontario's electricity grid. To advance action on reconciliation and ensure the completion of the Project to meet Provincial energy needs, it is being constructed in partnership with nine First Nations in the region, who will have the opportunity to invest in a 50 per cent equity stake in the transmission line component of the Project. Through an industry-leading approach partnership, the Project will advance to meet Provincial energy needs while providing innovative and lasting benefits to Indigenous communities in procurement, employment, economic benefits and investment opportunities.

[4] Exhibit B, Tab 3, Schedule 1, Attachment 8 Pg. 3

APPORTIONING PROJECT COSTS & RISKS

1.0 PROJECT COST INFORMATION

The following exhibit will provide information and detail regarding the cost elements of the Project in total, and by phases, the following table is a summary of that information.

Table 1 - Summary of Project Costs by Line, Station and Project Phase

($M's)	Phase 1	Phase 2	Total
Line Cost	$546.1	$447.6	$993.7
Station Costs	$155.0	$51.3	$206.3
Total Cost	$701.1	$498.9	$1,200.0

The costs tables below are separated into Phase 1 and Phase 2 of the Project, due to the in-service timing of each.

PHASE 1 – 230 KV DOUBLE-CIRCUIT TRANSMISSION LINE BETWEEN LAKEHEAD TS AND MACKENZIE TS

The estimated capital cost of Phase 1 is shown below, separated by line and station categories:

Table 2 - Phase 1 Line Cost

	Estimated Cost ($M's)
Materials	108.6
Labour	142.0
Equipment Rental & Contractor Costs	150.9
Sundry	7.7
Contingencies	57.2

Overhead[1]	16.3
Capitalized Interest[2]	28.7
Real Estate	34.7
Total Line Work	**$546.1**

Table 3 - Phase 1 Station Cost

	Estimated Cost ($M's)
Materials	56.4
Labour	50.4
Equipment Rental & Contractor Costs	16.2
Sundry	3.2
Contingencies	17.4
Overhead [1]	4.4
Capitalized Interest [2]	7.0
Total Station Work	**$155.0**

PHASE 2 – 230 KV SINGLE-CIRCUIT TRANSMISSION LINE BETWEEN MACKENZIE TS AND DRYDEN TS

The estimated capital cost of Phase 2 is shown below, separated by line and station categories:

[1] Overhead Costs allocated to the Project are for Common Corporate Costs. These costs are charged to capital projects through an overhead capitalization rate. As such they are considered "Indirect Overhead".
[2] Capitalized Interest 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.

Table 4 - Phase 2 Line Cost

	Estimated Cost ($M's)
Materials	88.9
Labour	122.5
Equipment Rental & Contractor Costs	125.1
Sundry	6.8
Contingencies	42.7
Overhead[1]	13.5
Capitalized Interest[2]	24.3
Real Estate	23.7
Total Line Work	**$447.6**

Table 5 - Phase 2 Station Cost

	Estimated Cost ($M's)
Materials	14.8
Labour	18.7
Equipment Rental & Contractor Costs	6.4
Sundry	1.3
Contingencies	6.3
Overhead [1]	1.4
Capitalized Interest [2]	2.4
Total Station Work	**51.3**

The costs for both Phase 1 and Phase 2 work provided above allows for the schedule of approval, design and construction activities provided in **Exhibit B, Tab 11, Schedule 1**.

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

The preferred route for the Project has been established and the final EA is being prepared to submit to the MECP for a decision. To date, a significant number of appraisals for the real estate component of the estimate have been finalized, as further described in **Exhibit E, Tab 1, Schedule 1.** Hydro One has achieved voluntary early access agreements on 79% of the properties affected by the corridor.

The Project lines estimate is based on a fixed price EPC contract that was underpinned by two years of early contractor involvement that allowed two EPC contractors to be involved with the development of Project definition and scoping. Hydro One then issued an RFP, where two qualified EPC contractors provided a fixed price to construct the transmission line of the Project. This procurement process allowed the EPC contractors to obtain competitive market pricing from their suppliers and vendors and to identify and evaluate, engineering, procurement, construction, risks and opportunities during the development of their respective offers. Thus, the cost estimate reflects current market-tested EPC pricing to deliver the Project, along with corresponding risk that will be transferred to the EPC contractor.

2.0 DELIVERY OF NEW LARGE-SCALE TRANSMISSION PROJECTS

To construct the large number of new transmission line projects required in Ontario, Hydro One has undertaken several new initiatives to deliver these projects in a cost-effective, efficient, and timely manner. For instance:

i. Hydro One has implemented a policy that provides 50/50 equity opportunities to First Nations for greenfield transmission line projects forecast to cost greater than $100 million. This Policy enables Hydro One to advance reconciliation as well as

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[3] An estimate range of -20%/+30%

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

build mutually beneficial, collaborative, and long-lasting relationships with Indigenous communities impacted by large transmission line projects.

ii. In EB-2021-0169, Hydro One applied to the OEB and was granted approval for the ATP Account to track costs for transmission line projects that are expected to be owned by a new transmission partnership. This allows Hydro One to commence development activities at an earlier stage, when key project deliverables are still unknown (e.g. project route, preliminary engineering, land acquisition requirements) that are required to produce a project cost estimate.

Another initiative developed by Hydro One to augment its ability to deliver these new transmission projects is to utilize an Early Contractor Involvement delivery model. The ECI delivery model engages the services of an external engineering firm and the services of EPC contractors (referred to here-on as “ECI-EPC”). This initiative allows the ECI-EPC contractor to be engaged at an earlier stage of development (typically at a preliminary budgetary estimate stage rather than near the end of detailed estimating or at construction initiation). As such, the ECI-EPC contractor performs many of the development functions that under the standard Hydro One EPC delivery model would be performed internally by Hydro One.

Hydro One developed the ECI-EPC model for execution and construction of the types of large-scale projects that Hydro One anticipates being added to Ontario’s transmission system in the future.

3.0 IMPACT OF ECI-EPC MODEL ON OVERHEAD CAPITALIZATION

A portion of Hydro One’s overheads are allocated to capital expenditures as recognition of the amount of indirect support required to support Project capital work. These allocated costs (overheads) are additional to any directly attributable costs.

Based on Atrium Economics' recommendation[5], Hydro One is implementing a new overhead capitalization approach to their Project execution model for large-scale projects, such as the Waasigan Project. Hydro One engaged Atrium Economics to review Hydro One's current overhead capitalization methodology to determine if adjustments were warranted for the new execution model. To be consistent with Hydro One's existing overhead capitalization guiding methodology and principles, Atrium Economics' conclusion and subsequent recommendation is that a refinement is warranted when calculating Hydro One's overhead rate for projects subject to the ECI-EPC delivery model. The basis for an update to Hydro One's overhead allocation rate is that fewer indirect resources (i.e., overheads) from Hydro One are required to support the Project because these overheads are being incurred by the ECI-EPC. Furthermore, Atrium Economics[6] has also highlighted the following.

- ECI-EPC executed projects are multi-year and significantly larger in scale, and cost, compared to most of Hydro One's transmission projects contemplated in its TSP. As a result, many Hydro One Common Corporate functions in support of the ECI-EPC Projects are being directly assigned from common corporate costs centers versus being allocated through an overhead allocation rate.

- The recommended overhead rate that Hydro One should use is a blended overhead rate determined by the weighted average portion of projects costs which (i) are non-ECI-EPC and should attract the standard Transmission overhead rate as they rely on corporate support functions, and (ii) are ECI-EPC and do not rely on Corporate support functions as discussed above.

[5] Based on the findings contained in the Atrium Economics' Report 'Overhead Capitalization Methodology for ECI-EPC Contracted Projects' included at Exhibit B, Tab 7, Schedule 1, Attachment 1 to this Application.
[6] A report from Atrium Economics is expected to be issued to Hydro One in August 2023, and will be included as supplemental evidence to this Application at that time. The filing of the report with this Application's evidence is expected to occur prior to the OEB's first Procedural Order being issued.

Accordingly, Hydro One has implemented these recommendations in the Waasigan Project's cost estimate.

4.0 IMPACT OF METHODOLOGY ON THE WAASIGAN PROJECT

The recommended calculation of an ECI-EPC project's overhead rates is to adopt the blended overhead rate described above. Specific annual rates are disclosed in Table 6 below. This rate will be reviewed annually as part of the annual Integrated Business Planning process.

The Waasigan Project is the first of several future projects that will use the ECI-EPC overhead capitalization methodology. Hydro One intends to use the following overhead capitalization rate for these types of projects, including the Waasigan Project. Due to the ECI-EPC projects spanning multiple years, a 5-year weighted average rounded overhead rate will be applied to these types of projects' annual capital expenditures.

Table 6 - Hydro One's Overhead Capitalization Rate for ECI-EPC Projects

ECI-EPC Projects	2023	2024	2025	2026	2027	5-year avg	Rounded
Blended Overhead Rate	2.6%	2.6%	2.4%	2.5%	2.6%	**2.5%**	**3.0%**

5.0 RISKS AND CONTINGENCIES

As with most projects, there are risks associated with estimating costs. Hydro One's cost estimate includes an allowance for contingencies in recognition of these risks.

The top three Project risks are outlined below. These risks are the major contributors to the total contingency suggested for this project:

- Land Acquisition – Risk of owners not accepting Hydro One's voluntary agreements, which may lead to expropriation.
- Engagement and Consultation – Risks associated with local government and/or leadership changes that would affect relationships and agreements.

- Approvals, Permits and Authorizations – Risk of delay when obtaining the necessary approvals, permits and authorizations, such as the EA, S.92 Leave to Construct and archaeology.

Cost contingencies that have not been included, due to the unlikelihood or uncertainty of occurrence, include:
- Labour disputes;
- Safety or environmental incidents;
- Significant changes in costs of materials outside the control of Hydro One since the estimate preparation; and
- Any other unforeseen and potentially significant event/occurrence.

6.0 COST OF COMPARABLE PROJECTS - LINES

The OEB's *Filing Requirements for Electricity Transmission Applications, Chapter 4*, requires the Applicant to provide information about a cost comparable project constructed by the Applicant. Table 7 below presents the cost, construction, and technical comparisons of the lines scope of the Project to that of the recently in-serviced Hawthorne to Merivale, Powering South Nepean, WATR Projects constructed by Hydro One, and a fourth project, East-West-Tie which was constructed by Upper Canada 2 Transmission, Inc. These projects were selected as reasonable comparators because they are double-circuit 230 kV transmission lines, they utilize similar conductor types, and they are either completely, or predominantly built using steel lattice structures. The scopes of these projects are summarized below:

- **Hawthorne to Merivale Reconductoring Project:** Upgrading of two 230 kV transmission circuits connecting Hawthorne TS and Merivale TS, in the City of Ottawa by reconductoring the existing single conductor per phase 230 kV M30A and M31A circuits with a dual-bundled (two conductors per phase) circuit configuration over a distance of approximately 11.9 km. The two circuits are each carried on separate, and adjacent, towers along the Hawthorne TS to Merivale TS corridor route. Leave to construct approval for this project was provided under OEB docket EB-2020-0265.

- **Power South Nepean Project**: Upgrading an existing 115 kV single-circuit transmission line to construct a new 230 kV double-circuit transmission line (approximately 12.2 km) to address capacity needs in the South Nepean Area of Ottawa. The new 230 kV double-circuit line transmission replaced approximately 10.9 km of the existing 115 kV single-circuit transmission line (S7M) from West Hunt Club Road to Cambrian Road and extended an approximate 1.3 km from Cambrian Road to the new MTS. Leave to construct approval for this project was provided under OEB docket EB-2019-0077.

- **WATR:** Upgrading approximately 13.6 km of double circuit 230 kV line to replace an existing double circuit 115 kV line between Ingersoll TS and Woodstock TS utilizing a combination of steel lattice towers and steel pole structures. The WATR project lands consisted of a mix of provincially owned properties, easement rights on private properties and municipal road corridors. The project went into service in March 2012. Leave to construct approval for this project was provided under OEB docket EB-2007-0027.

- **East West Tie:** Construction of a new 450 km long transmission line spanning 235 km from Lakehead TS to Marathon TS, and then continuing another 215 km from Marathon TS, around Pukaskwa National Park to Wawa TS (owned by Upper Canada Transmission 2, Inc.). Leave to construct approval for elements of this project was provided under OEB docket EB-2017-0182.

Table 7, below, has been adjusted to show comparable projects in 2026 dollars utilizing inflation values for future years consistent with the inflation parameters provided by the OEB. For the purposes of the comparison, Hydro One has excluded real estate costs from the Project and comparable projects. When considering the cost per km ratio for all other transmission line costs in Table 7, the comparable projects demonstrate that the estimate for the Project is within a reasonable range to that of comparable transmission line works. However, there are some primary factors contributing to, in some instances, a higher project cost. The primary two are described below as;

1. *Procurement Costs*: Procurement challenges are being experienced globally by the industry. For example, for project procurement, much has changed in the industry since the comparable projects procurement activities were undertaken. As described in Hydro One's OEB-approved 2023-27 revenue requirement application[7], external pressures on the industry have caused significant price increases across the industry. The price of essential commodities has a significant impact on project costs. Equipment purchased to construct transmission lines (e.g., steel towers, conductors and miscellaneous hardware) is heavily impacted by certain raw material indices. Essential commodities such as copper, aluminum and steel have undergone price increases and supply shortages. For reference, from January 2021 to January 2022, the price of copper has increased by 27.1%, aluminum has increased by 41.6% and steel has increased by 111.6%[8].

2. *Engagement and Consultation*: A significant difference between this Project and the comparators is the magnitude of engagement and consultation required both on the development and execution of the Project. The Project has been required to undertake a multi-year comprehensive Environmental Assessment and consultation with 21 Indigenous communities and organizations. Engagement has been extensive while also having to adapt throughout the process to the restrictions of COVID-19.

[7] EB-2021-0110 – Exhibit O, Tab 1, Schedule 2 – Filed March 31, 2022.
[8] Based on the following indices for copper, aluminum, and steel, respectively: Copper (New York), Aluminum N. America, and Steel Plate N. America from January 2021 to January 2022.

Table 7 - Costs of Comparable Lines Projects - Lines

Project (Costs are in $M's)	Hawthorne x Merivale Conductor Upgrade	South Nepean DETL Estimate South Nepean Trans Reinforcement	WATR Ingersoll x Karn x Woodstock	Upper Canada Transmission Inc. East-West Tie Line	Waasigan Transmission Lines Project
Circuit Nomenclature	M30A/M31A	S7M/E34M	M32W/M31W + K12/K7	M37L/M38L	A30L/A31L (Phase 1) D32A (Phase 2)
Voltage	230 kV	230 kV	230 kV	230 kV	230 kV
Structure Type	Steel Lattice	Steel Lattice (10%) Steel Pole (73%), BPE/BPD (17%)	Steel Lattice (83%) Steel Pole (10%), BPE/BPD (7%)	Steel Lattice	Steel Lattice Towers
Circuit Type	Double	Double	Double	Double	Double/Single[9]
Conductor	1192 kcmil	997 kcmil	1443 kcmil	1192 kcmil	795 kcmil
Location	Eastern Ontario, Rural	Eastern Ontario, Rural	Southern Ontario, Rural	Northern Ontario, Rural	Northern Ontario, Rural
In-Service Year	June 2023	November 2021	March 2012	2022	2025/2027
Estimate/Actual	Actual	Actual	Actual	Estimate[10]	Estimated
Cost ($M's)	$39.4	$51.3	$35.6	$935.9	$992.7
Less;					
Real Estate	0.9	2.2	0.5	23.3	62.5[11]
Bypass	N/A	1.4	4.3	N/A	N/A
Micropiles	N/A	6.7	N/A	N/A	N/A
Adjusted Costs	38.5	40.9	30.8	912.6	934.3
Escalation Adjustment[12]	5.4	8.8	13.7	169.88	N/A
Escalated Total Project Cost	43.9	49.7	44.5	1,082.5	N/A
Length	12.0	12.2	13.6	450	360
Cost per Km	**3.7**	**4.1**	**3.3**	**2.4**	**2.6**

[9] Double circuit length is 190km, single circuit length is 170km.
[10] Per report from Upper Canada Transmission for the *East-West Tie Line Quarterly Construction Progress Report* dated January 20, 2023. Docket EB-2017-0182.
[11] This amount includes the direct real estate costs identified in Table 1 ($69,683) plus contingency carried for expropriation, interest and overhead.
[12] Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.

7.0 COST OF COMPARABLE PROJECTS - STATIONS

For station cost comparison purposes, Table 8 and Table 9 below illustrate the cost, construction, and technical comparisons of the Waasigan station upgrade works for Phase 1 and Phase 2 respectively. Unlike making a line comparison, where a per-kilometer cost can be derived, the same methodology and inferences for stations' scopes of work cannot always be achieved. There are several major differentiating factors, based on the unique site and station configuration, that make comparing station cost components as a one-to-one comparison difficult. Notwithstanding this, the East West Tie Station Project is a project Hydro One recently completed that most closely aligns to Phase 1 of the Project, while Holland TS and Beach TS are the recent completed projects that most closely align to Phase 2 of the Project, for cost comparison purposes.

With respect to Phase 1 of the Project the East West Tie Station Project included work at three stations: Wawa TS, Marathon TS, and Lakehead TS. Costs, construction and technical comparisons are within Table 8 below.

Table 8 - Costs of Comparable Station Projects (Phase 1)

Project (Cost $M's)	**Wawa TS**	**Marathon TS**	**Lakehead TS**	**Lakehead TS Phase 1**	**Mackenzie TS Phase 1**
Technical	(6) 230kV Circuit Breakers, (19) Disconnect Switches, (5) CVTs, AC/DC Station Service, (1) P&C Building	(12) 230kV Circuit Breakers, (2) Reactors, (36) Disconnect Switches, (8) CVTs, AC/DC Station Service, (1) P&C Building	(8) 230kV Circuit Breakers, (1) Reactors, (20) Disconnect Switches, (8) CVTs, AC/DC Station Service, (1) P&C Building	(4) 230kV Circuit Breakers, (1) Reactors, (10) Disconnect Switches, (3) CVTs, AC/DC Station Service, (1) P&C Building	(5) 230kV Circuit Breakers, (2) Reactors, (14) Disconnect Switches, (6) CVTs, AC/DC Station Service, (1) P&C Building
Project Surroundings	Northern Ontario, Rural	Northern Ontario, Rural	Northern Ontario, Rural	Northern Ontario, Rural	Northern Ontario, Rural
In-Service Date	March 2022	March 2022	March 2022	December 2025	December 2025
Estimate or Actual	Actual	Actual	Actual	Estimate	Estimate
OEB-Approved Cost Estimate	Combined total of $157.3			-	-

Total Project Cost	$51.7 M[13]	$71.8	$57.7	$66.3	$88.7
Less Adjustments					
Less: Land Cost	N/A	N/A	N/A	N/A	N/A
Less: Line Entrance	N/A	N/A	N/A	3.7	0.8
Adjusted cost	**$51.7**	**$71.8**	**$57.7**	**$62.6**	**$87.9**
Escalation Adjustment[14]	**$7.2**	**$10.0**	**$8.0**	**N/A**	**N/A**
Total Comparable Project Costs	**$58.9**	**$81.8**	**$65.7**	**$62.6**	**$87.9**

With respect to Phase 2, Table 9 below illustrates the cost, construction, and technical comparisons of the Project to Holland TS and Beach TS projects.

Table 9 - Costs of Comparable Station Projects (Phase 2)

Project	Holland TS	Beach TS	Mackenzie TS Phase 2	Dryden TS Phase 2
Technical	(2) 230kV Circuit Breakers, (4) Disconnect Switches. (6) Line disconnect switches, (3) CVTs, AC/DC Service Station, P&C Building	(2) 230kV Breakers, (4) Disconnect Switches, (2) Line Disconnect Switches, AC/DC Station Service,	(1) 230lV Circuit Breaker, (2) Disconnect Switches,(1) Line Disconnect Switch, (1) CVT	(2) 230kV Circuit Breakers, (4) Disconnect Switches, (1) Line Disconnect Switch, (3) CVTs, AC/DC Station Service, 230kV Yard Expansion, Space Provision for (1) 40Mvar Reactor and components
Project Surroundings	Central Ontario, Rural	Southern Ontario, Rural	Northern Ontario, Rural	Northern Ontario, Rural
In-Service Date	December 2017	June 2016	December 2027	December 2027

[13] Together the three EWT Project stations total to Hydro One's, East-West Tie Station Project – EB-2017-0194 - Quarterly Report, Period Ending March 31, 2022 dated June 21, 2022, of $181.2M.
[14] Inflation adjustment factors used for comparator projects are consistent with the OEB inflation parameters described in EB-2021-0212 and the OEB letter titled '2023 Inflation Parameters' distributed October 2022.

Estimate or Actual	Actual	Actual	Estimate	Estimate
OEB-Approved Cost Estimate	N/A[15]	N/A[16]	-	-
Total Project Cost	$26.8	$21.5	$15.1	$36.2
Less Adjustments				
Less: Land Cost	N/A	N/A	N/A	N/A
Less: Line Entrance	N/A	N/A	1.2	0.0
Adjusted cost	**$26.8**	**$21.5**	**$14.0**	**$36.2**
Escalation Adjustment[17]	**$9.0**	**$7.0**	**N/A**	**N/A**
Total Comparable Project Costs	**$35.8**	**$28.5**	**$14.0**	**$36.2**

The major differences contributing to the price variation of these station projects include:

- Procurement: As a result of a several global factors that were not present for the comparative projects (i.e.; COVID-19, supply chain and the war in Ukraine), inflation in 2022 and 2023 resulted in significant price increases for major components, materials and equipment. In addition, the industry is experiencing additional risks associated with procurement including the need for longer lead times, material supply shortages, increased manufacturing pressure; all of which impact project costs.

[15] This project was encompassed within a previous Hydro One revenue requirement application. The project was not subject to leave to construct approval by the OEB. Therefore, the specific investment does not have a discrete OEB approval to appropriately reference for the purposes of this comparison.
[16] This project was encompassed within a previous Hydro One revenue requirement application. The project was not subject to leave to construct approval by the OEB. Therefore, the specific investment does not have a discrete OEB approval to appropriately reference for the purposes of this comparison.
[17] Inflation adjustment factors used for comparator projects are consistent with the OEB inflation parameters described in EB-2021-0212 and the OEB letter titled ‘2023 Inflation Parameters’ distributed October 2022.

- Execution Methodology: The comparative projects were executed where design, procurement and construction were undertaken by Hydro One. Additionally, for the comparable projects, their scopes, schedules, and risk profiles allowed for this execution methodology to be the most effective means of project delivery. For this Project, a fixed price EPC execution methodology has been selected to best define and manage project scope, schedule and risk while also providing cost surety in the delivery of a project of this magnitude.

- Project Scope: For the stations being impacted by this Project, those stations require expansion of the existing footprint (all will occur on existing Hydro One owned property). As a result, the Project scope, when compared to the comparators, is notably dissimilar in physical site requirements, site preparation, grading, underground infrastructure, grounding and access requirements. This leads to added Project complexity, planning and site coordination.

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ATRIUM ECONOMICS' REPORT
- OVERHEAD CAPITALIZATION METHODOLOGY
FOR ECI-EPC CONTRACTED PROJECTS

ATRIUM ECONOMICS
CENTERED ON ENERGY

Hydro One Networks Inc.

Overhead Capitalization Methodology for ECI-EPC Contracted Projects

August 9, 2023

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1 Executive Summary

1.1 Introduction

Hydro One asked Atrium Economics, LLC ("Atrium") to provide guidance and advice on a methodology for appropriately recovering overhead capitalization ("OH Cap") costs for ECI-EPC Contracted Projects (as defined below) through the application of an Overhead Capitalization Rate ("OCR"). This report discusses the underlying theoretical, conceptual, and methodological procedures utilized by Hydro One in their current OH Cap methodology as approved by the Ontario Energy Board ("OEB") in Hydro One's Joint Transmission and Distribution Rate Application for 2023-2027 ("JRAP" or "2023-2027 Application")[1] and presents a recommended method of recovering OH Cap costs relating to ECI-EPC Contracted Projects, and discusses the implications of this approach.

1.2 Background

As of 2021, Hydro One is utilizing an Early Contractor Involvement ("ECI") delivery model for affiliate Transmission Line Projects[2] that engages the services of an external Owner's Engineer ("OE") and the services of Engineering, Procurement, and Construction ("EPC") contractor for each significant Transmission system expansion spanning multiple years ("ECI-EPC Contracted Projects" or "ECI-EPC Delivery Model"). These ECI-EPC Contracted Projects are contracted at a significantly earlier stage of development (typically at the budgetary estimate instead of the late detailed estimate or construction estimate stage); when compared to Hydro One's standard EPC delivery model ("Standard Delivery Model" or "Standard Hydro One Tx Projects") currently utilized for sustainment and natural growth of the Transmission System.[3] As such, under the ECI-EPC approach, the OE/EPC contractors perform many of the development functions that would be performed internally under the Standard Delivery Model. Hydro One uses the ECI-EPC Delivery Model for such projects instead of the Standard Delivery Model that supports delivering the primary transmission portfolio as these projects exceed Hydro One's current internal capacity built to support standard system requirements. Due to ECI, the ECI-

[1] EB-2021-0110

[2] "The OEB notes that the costs that are to be recorded in this account are for projects which are the subject of an Order in Council or direction from the Minister of Energy or a letter from the IESO." from Finding of Issue 1 on Page 7 of DECISION AND ORDER EB-2021-0169 issued October 7, 2021

[3] The Standard Delivery Model could also include instances where an EPC is not utilized.

EPC contractor will thoroughly understand the risks, costs, and challenges associated with the project, thus giving greater certainty to Hydro One on the overall schedule and cost.

Directed Transmission Line Projects that are expected to fall under the Affiliate Transmission Projects Regulatory Account established in EB-2021-0169 (the "ATP Account")[4], were not included in the JRAP and are anticipated to be performed under the ECI-EPC Delivery Model.

1.3 Principal Considerations & Conclusions

As explained in more detail in this report:

- Hydro One identified a need to review the appropriateness of its current method of recovering overhead costs from the ECI-EPC Contracted Projects.
- Hydro One retained Atrium to provide guidance and advice on reviewing the nature of shared services[5] provided by Hydro One for ECI-EPC Contracted Projects and provide a recommended methodology for appropriately recovering OH Cap costs for ECI-EPC Contracted Projects.
- Through the review, Atrium determined that the size and delivery model of Hydro One's ECI-EPC Contracted Projects warrants a refinement to the calculation of the OCR as the nature of the shared services provided by Hydro One are different than those provided under the Standard Delivery Model. As such, there are different implications on the common corporate costs incurred by Hydro One in support of these capital projects.
- Hydro One estimates that 79.5% of the costs associated with ECI-EPC Contracted Projects relate to external contractor payments, and 20.5% relate to internal Hydro One incurred costs.
- Through cost analyses, as detailed in Section 5 of this report, Atrium determined

[4] Various components of Station work with respect to the project may be executed using the ECI-EPC Delivery Model.

[5] Shared services means the centralized business operations that support multiple businesses, affiliated companies, or multiple parts of the same organization. Common corporate costs are costs incurred to provide shared services to Hydro One and its affiliate companies.

an appropriate OCR is 79.5% of the costs associated with external contractor payments, averaging 1.0% over five years.

- Atrium recommends applying the OCR rate that is currently applied to projects under the Standard Delivery Model to the 20.5% of project costs that relate to internal Hydro One incurred costs (i.e., not ECI-EPC costs).
- The resulting recommendation is for Hydro One to modify its current OH Cap recovery method for these ECI-EPC Contracted Projects such that the ECI-EPC Contracted Projects are subject to a blended OCR that reflects the appropriate burden placed on Hydro One's shared services.
- This blended rate is calculated using the OCR mentioned above (five-year average of 1.0%) weighted at 79.5% and the standard OCR, currently applied capital projects under the Standard Delivery Model, to capital weighted at 20.5%.
- Atrium recommends using a five-year average as it reflects these projects' long duration, and also recommends reviewing the five-year average annually. Refinements may be required for efficient and effective operational and accounting administration.

Atrium believes this recommended methodology for recovery of overhead costs associated with ECI-EPC Contracted Projects aligns with the criteria and methods currently employed by Hydro One to allocate costs incurred to provide shared services to Hydro One and its affiliate companies. Specifically, the ECI-EPC Contracted Projects overhead cost recovery methodology fairly attributes and recovers these costs from the ECI-EPC Contracted Projects, ensuring the prudent and fair cost allocation to Hydro One's ratepayers.

2 Guiding Principles of Cost Allocation

2.1 The Need for Cost Allocation

Activities require cost allocation when existing accounting methodologies do not include tracking costs for providing services to recipients. Tracking one's time is not always practical or preferred, as activity-based time tracking isn't always an efficient use of one's time and resources. In instances where activity-based time tracking is not preferable, utilizing cost allocation principles and methods is beneficial. For example, cost allocation is preferable to activity-based time for employees working on processes or projects that benefit multiple business entities simultaneously.

2.2 Principles Of Cost Allocation

With cost responsibility following cost causation as the guiding principle, company policy and allocation methodology should satisfy the following criteria:

- The method should be based on cost causation. Cost causation means a causal relationship exists between the basis used to allocate a cost and the cost incurred. Costs are recognized as being caused by a service or group of services if (i) the costs are brought into existence as a direct result of providing the service or group of services; or (ii) the costs are avoided if the service or group of services is not provided.
- If cost causation is inappropriate in a given situation, the method often utilized is benefits received (i.e., allocated to the business that received the benefits).
- Underlying data used for implementing the method should be obtained at a reasonable cost and be objectively verifiable in the initial and subsequent years.
- Estimates used for the allocation method should be unbiased, reasonably consistent with comparable data, and provided by employees familiar with the costs.

3 Hydro One's Current Corporate Overhead Recovery

3.1 Overview

Hydro One's Corporate Cost Allocation addresses the following considerations:

- Methods comply with the relevant provisions of the OEB Affiliate Relationships Code for Electricity Distributors and Transmitters.[6]
- Cost incurrence - The costs are needed to perform services the business requires.
- Cost allocation - The costs are appropriately allocated among businesses using cost drivers/allocation factors supported by principles of causality.
- Cost/benefit - The benefits received equal to or exceed the cost.

[6] Affiliate-Relationships-Code-ARC-Electricity-20100315.pdf (oeb.ca)

The Corporate Cost Allocation is detailed in Hydro One's 2023-27 Joint Rate Application (EB-2021-0110) within a Hydro One commissioned report by Black & Veatch relating to the Corporate Cost Allocation review undertaken in 2021.[7] This report finds the Corporate Cost Allocation continues to be appropriate for Hydro One because:

- It meets generally acceptable regulatory practices for cost allocation since it distributes costs based on cost causation, including the use of direct assignment when possible, and then using cost drivers.
- It has been accepted by the OEB.
- It has the support of Hydro One management and is understood and accepted by Hydro One, its affiliate companies, and the Transmission ("Tx") and Distribution ("Dx") businesses.
- It allows Hydro One, its affiliate companies, and the Tx and Dx businesses to determine precise charges by department and by activity. This transparency provides a basis for understanding the nature of the charges and value of the services received.
- It is well integrated with Hydro One's annual business planning process and produces reasonably stable results over time.
- It accommodates changes in Hydro One's organization and can be adapted easily to reflect those changes.

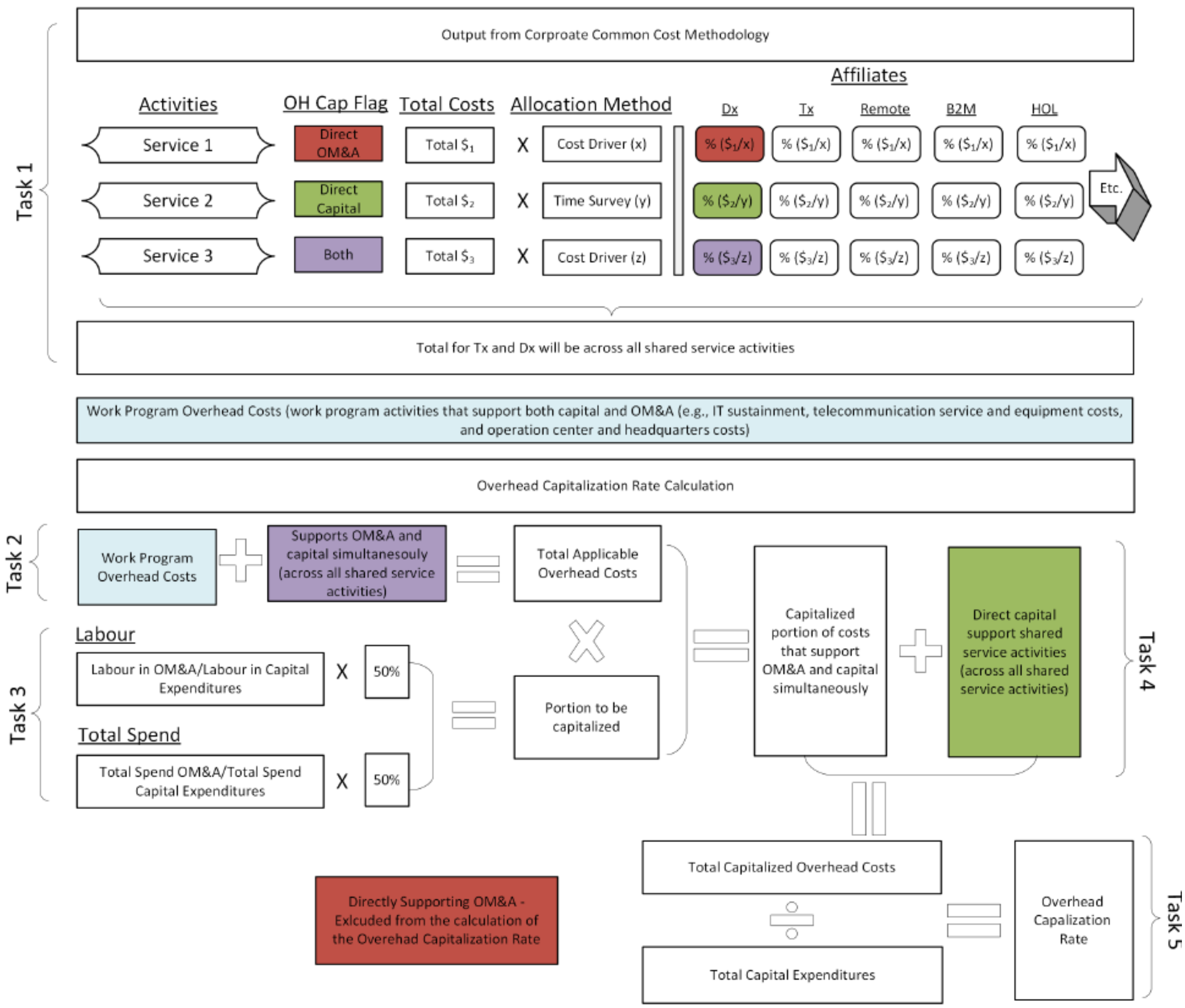
OCRs are percentages that are applied to the cost of Transmission and Distribution capital expenditures resulting in a portion of common corporate costs being included as part of capital expenditures for each business. The OCR is used to recover common corporate costs that are not directly recorded to capital expenditures due to the nature of the costs; either for employees who support capital expenditures but do not directly charge time to a specific capital project (assigned for less than three months or work on multiple projects simultaneously) or for employees who perform work that impacts both capital and OM&A projects.

The output from the Overhead Capitalization Rate Methodology consists of two percentages (Overhead Capitalization Rates for Tx and for Dx) that are applied to the costs of Tx and Dx

[7] Black & Veatch Report as filed in EB-2021-0110, Exhibit E-4-8, Attachment 1. Mr. Taylor of Atrium, in his former capacity with and as a subcontractor to B&V, has been the lead expert in connection with the B&V Report.

capital expenditures, as applicable, to recover the portion of common corporate costs that support capital expenditures for each business. This process is depicted in Figure 1 below.

Figure 1 – Overhead Capitalization Rate Methodology



4 Need for a Specific OCR for ECI-EPC Contracted Projects

Hydro One internally determines which projects will follow the ECI-EPC Delivery Model. Atrium's conclusion through interviews with Hydro One staff is that these ECI-EPC Contracted Projects are unique for several reasons: (i) their delivery model engages outsourced services much earlier in the project; (ii) they rely on outsourced services more fully and across more stages of the project; and (iii) their size and duration are higher than Standard Hydro One Tx

Projects. As such, the common corporate costs incurred by Hydro One to support these ECI-EPC Contracted Projects is of a different level than Standard Hydro One Tx Projects, as demonstrated by the following descriptions:

- A significant portion of each project's total cost relates to OE and ECI-EPC Contracted work (i.e.. Hydro One determined that 79.5% of the capital expenditures will be payments to external contractor and only 20.5% will relate to internal Hydro incurred costs).
- The EPC contractors are engaged much earlier in the process through Hydro One's ECI process and perform many of the development functions that, under the Standard Delivery Model, are undertaken internally by Hydro One.
- The projects are multi-year and significantly more extensive than most standard Transmission projects, which leads to a portion of Hydro One Common Corporate functions support being directly assigned from common corporate costs centers (e.g., most indigenous affairs, system planning, and land acquisition are all directly charging time to these projects).[8]
- For ECI-EPC Contracted Projects, the level of support provided by internal Hydro One functions per dollar of capital is significantly lower.[9]

5 Development of OCR Specific to ECI-EPC Contracted Projects

5.1 Review of Costs within OCR

One of the first steps conducted by Atrium was to review the Lines of Business that are designated as providing Common Corporate Costs directly to capital work or included as part of the overhead capital costs within the Overhead Capitalization Rate Methodology contained in Hydro One's 2023-2027 Application. The Applicable Capital Overhead costs are activities that

[8] As noted in the Black & Veatch Report as filed in EB-2021-0110, "In instances when costs associated with Common Corporate Costs can be directly attributed to work for a specific affiliate and are expected to be for a minimum period of three months, those costs are transferred via variable timesheets or automatic transfers."

[9] An estimated 23 Hydro One staff will be dedicated to ECI-EPC projects with ~$500M annual capital expenditures, compared to ~4,200 Hydro One transmission staff (OEB application EB-2021-0110, Appendix 2-K) supporting ~$1,500M annual capital expenditures (EB-2021-0110, O-01-02, Table 4).

support both OM&A and capital and are split between (a) costs that remain in OM&A and (b) costs that will be included in the Overhead Capitalization Rate calculation by multiplying the Total Applicable Overhead Costs by a ratio developed using a 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio.

Hydro One personnel indicated that employees within the Lines of Businesses included as Direct Capital in the Overhead Capitalization Rate Methodology will directly charge to these ECI-EPC Contracted Projects. These include Indigenous Relations, Planning, and System Control.

A second review was conducted to ascertain the methods used to assign the overhead capital costs to the Transmission business. Those allocation methods are provided below:

- Direct Assignment - Time Survey
- Capital, Labour, Revenue
- Headcount
- Internal - Total Cost Center Labour (non-labour)
- Program & Project Costs
- Project Costs Capital
- Union Employee Headcount
- Labour Costs
- Board of Directors Labour Costs
- Information System Direct Assignment
- Defined Contributions Headcount

While the Overhead Capitalization Rate Methodology uses cost drivers to allocate Direct Capital and Applicable Capital Overhead costs to the Transmission business, there is no separation between the projects within the Transmission business. However, information is available on the split of these cost drivers between ECI-EPC Contracted Projects and all other Standard Hydro One Tx Projects. This information was gathered and used to further disaggregate the allocation of Common Corporate Costs across different types of Transmission projects.

5.2 Disaggregate Transmission Related Direct Capital Costs & Applicable Capital Overhead Costs using Sub-Allocation Factors

As indicated above, the Common Corporate Costs allocated to the Transmission business relate to two distinct types of costs (1) Direct Capital - employees who support capital expenditures but do not directly charge time to a specific capital project, and (2) Overhead Capital - employees who perform work that impacts both capital and OM&A projects. The proposed method of developing an OCR for ECI-EPC Contracted Projects is first to disaggregate the Transmission related direct capital and overhead costs between those that support the ECI-EPC Contracted Projects and the Standard Hydro One Tx Projects. Sub-allocation factors were developed for each allocation method used in the Corporate & Shared Cost Allocation Methodology to disaggregate these costs. Figure 3 below maps the allocation factors used in the Corporate & Shared Cost Allocation Methodology to initially assign these costs to the Transmission business and the sub-allocation factors used to disaggregate costs between ECI-EPC Contracted and the Standard Hydro One Tx Projects. As mentioned above, most employees within the Line of Business (1) Indigenous Relations, (2) Planning, and (3) System Control are directly charging costs in support of these ECI-EPC Contracted Projects. These costs are allocated to the Transmission business using the allocation method 'Direct Assignment – Time Survey,' and the sub-allocation factor for these costs is 'Direct Assignment to Non-ECI.' There are additional costs within the allocation method 'Direct Assignment – Time Survey' relating to Facilities which was based on a headcount allocation between Transmission and Distribution, and the proposed method is to use Headcount as a sub-allocation factor for these Facilities' costs.

Figure 2 – Disaggregation of Tx Related Direct Capital Costs & Applicable Capital Overhead Costs

Allocation Method	Sub-Allocation Factor
Direct Assignment - Time Survey	Direct Assignment to Non -ECI, Headcount for Facilities
Capital, Labour, Revenue	Capital, Labour (50/50)
Headcount	Headcount
Internal - Total Cost Center Labour (non-labour)	Labour Costs
Program & Project Costs	Program & Project Costs
Project Costs Capital	Project Costs Capital
Union Employee Headcount	Union Employee Headcount
Labour Costs	Labour Costs
Board of Directors Labour Costs	Capital, Labour (50/50)
Information System Direct Assignment	Headcount
Defined Contributions Headcount	Headcount

Using a multi-factor allocation to allocate costs that cannot be directly charged and for which a single cost allocation factor cannot be easily identified is a widely respected and common practice across the utility industry. The Corporate & Shared Cost Allocation Methodology uses a three-factor formula, with each factor equally weighted, and is generally referred to as the Massachusetts Formula, where the three components of the factor are representative of (1) Capital, (2) Revenue, and (3) Labour. These costs are further disaggregated using a 50/50 weighting of capital and labour given the insufficiency of using revenue as a sub-allocation factor (i.e., ECI-EPC Contracted Projects may not have revenue for several years). The result of this process for the budget plan years (2023-2027) is a total Direct Capital and total Applicable Capital Overhead Costs associated with ECI-EPC Contracted Projects.

5.3 Calculate OCR for the Portion of ECI-EPC Contracted Projects Fully Outsourced to OEs and EPCs

The resulting total Direct Capital and total Applicable Capital Overhead Costs associated with ECI-EPC Contracted Projects are then utilized in an OCR Calculation identical to the OCR Calculation used for the Tx business as approved in Hydro One's 2023-2027 Application. The OCR Calculation is calibrated to contain inputs (e.g., total capital expenditures) relating only to ECI-EPC Contracted Projects. This aligns the numerator (i.e., the allocation of costs to these ECI-EPC Contracted Projects) with the denominator (i.e., total capital associated with ECI-EPC Contracted Projects). The resulting OCR for the 79.5% of costs associated with external contractor payments averaged 1.0% over five years.

5.4 Develop Blended Rate for ECI-EPC Contracted Projects

To account for the fact that 79.5% of the costs associated with ECI-EPC Contracted Projects relate to external contractor payments and 20.5% relate to internal Hydro One incurred costs, a blended rate was developed. This blended rate was calculated using the OCR for the 79.5% of costs associated with external contractor payments (described in Section 5.3) weighted at 79.5% and the standard delivery Tx OCR weighted at 20.5%. The results are shown in Figure 4 below.

Figure 3 – Blended OCR for ECI-EPC Contracted Projects

ECI-EPC Projects	2023	2024	2025	2026	2027	5-year avg	Rounded
Blended Overhead Rate	2.6%	2.6%	2.4%	2.5%	2.6%	2.5%	**3.0%**

Atrium reviewed the results of this updated OCR and evaluated the appropriateness of setting an annual OCR for ECI-EPC Contracted Projects compared to setting an OCR based on an average of overhead costs and capital expenditures. Atrium noted large deviations in forecasted capital expenditures associated with ECI-EPC Contracted Projects (e.g., the total capital expenditures for these projects can increase more than 100% without seeing a material change in overhead costs).[10] As such, Atrium suggested a five-year average should be used for the ECI-EPC OCR rate.

5.5 Application and Monitoring of the Overhead Capitalization Rates

The blended rates shown in Figure 4 are developed based on forecast numbers and other estimates. Hydro One reviews and adjusts the OCR periodically to reflect changes in capital spending and associated support costs. Capitalized overheads are trued-up (in-year) at year-end to reflect actual results for capital implemented under the Standard Delivery Model. Given the proposed multi-year average for the ECI-EPC Contracted Projects, Atrium recommends Hydro One annually evaluate the OCR calculation for each year and ascertain if the OCR for the 79.5% of costs associated with external contractor payments used in the blended rate should be updated.

6 Conclusions and Recommendations

Atrium recommends that Hydro One adopt a blended OCR based on the analyses conducted and described in Section 5 of this report. The recommended methodology and resulting OCR reflect the level of common corporate costs provided to these ECI-EPC Contracted Projects and are consistent with the following guiding regulatory principles:

- Defensible Cost Causation: To conform to regulatory principles, the methodology should show a causal link between recovery of overhead and facilitation costs and capital activity.
- Distinguishable Costs: The overhead costs should be distinguished from those directly charged to these projects (i.e., no duplication of costs and distinct sets of costs to be included in overhead).
- Transparency: The methodology and calculations should be easy to follow and understand by internal users and external reviewers.
- Stability: The methodology should remain stable from year-to-year and not result in disproportionately large variations.

[10] This underscores the nature of these projects; that early involvement of third-party EPC contractors can be leveraged to undertake large capital expenditure projects with little additional overhead costs being incurred directly by Hydro One.

- Accuracy of Underlying Data: Any data used in the methodology should be accurate and able to be relied upon for the purposes intended (i.e., provide an appropriate measure and reasonable approximation of the underlying volume of activity or output).
- Flexibility/Adaptability: The methodology should accommodate changes in organizational structure, availability of data, business processes, and information systems with reasonable ease. Where possible, the method should automatically adjust for changes in circumstances (i.e., reconciliation processes).
- Cost-effectiveness: Methodologies should be cost-effective to implement. Additional accuracy may require significant incremental cost; thus, an appropriate balance is required between precision and cost, in relation to both implementation and ongoing costs.

CONNECTION PROJECTS REQUIRING NETWORK REINFORCEMENT

This is not a connection project. Facilities being constructed 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

Project costs will be included in the network pool for cost classification. See **Exhibit B, Tab 2, Schedule 1**, for information on the proposed work. No customer contribution is required for the Project.

The discounted cash flow analysis shown in Tables 1 and 2, below, conclude that based on the estimated cost of $1,200 million[1], plus the assumed impact on the future capital cost allowance and Hydro One corporate income tax, the Project will have a negative net present value of $889.8 million. Incremental operating and maintenance costs of the Project were forecast using system average OM&A estimates for the station capital expenditures and 360 km of line connection facilities.

2.0 COST RESPONSIBILITY

Network Pool

The Waasigan Project will increase the load meeting capability of the region and will meet the region's summer supply capacity needs for the "Transfer West into Mackenzie" (TWM) interface of 206 MW based on a Moderate Growth scenario by releasing constraints on transfers into the region. The Project is a good foundation, and steppingstone, for additional load growth. The approximate 206 MW of potential growth can result in $13.3 million in annual incremental network revenue over a 25-year evaluation period using 2023 UTRs. This Project is not associated with any specific load increase or customer load application.

Lakehead TS, Mackenzie TS and Dryden TS are network stations hence the new circuits will be included in the Network Pool as they directly connect these stations and meet the

[1] Project cost of $1,200m with $1m that is forecasted to be project OM&A which is displayed as removal cost in the NPV report.

IESO's identified needs. No customer capital contribution is required, consistent with the provisions of Section 6.3.5 of the TSC.

3.0 RATE IMPACT ASSESSMENT

The analysis of the Network pool rate impacts has been carried out on all transmitters' revenue requirement for the year 2023, and the 2023 approved Ontario Transmission Rate Schedules[2]. The Network pool revenue requirements would be affected by the Project based on the Project cost allocation.

Network Pool

Based on the total Project's initial cost of $1,200 million and the associated network pool incremental cash flows, there will be a change in the network pool revenue requirement once the Project's impacts are reflected in the transmission rate base. The analysis shows phased in servicing for Phase 1 at December 15, 2025 and Phase 2 at December 15, 2027. The 2023 OEB approved Network rate of $5.37 kW/month increases to $5.71 kW/month by year 4, then decreases to $5.65 kW/month by year 25. The maximum revenue shortfall related to the proposed facilities will be $81.3 million in the year 2032. The detailed analysis illustrating the calculation of the incremental network revenue and rate impact is provided in Tables 3 and 4, below.

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

Based on the load forecast, initial capital costs and ongoing maintenance costs, adding the costs of the required facilities to the Network pool will cause a $0.56 per month increase in a typical residential customer's rates under the Regulated Price Plan. 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.

[2] OEB Decision and Rate Order 2023 Uniform Transmission Rates (EB-2023-0101)

A. Typical monthly bill	$135.28 per month
B. Transmission component of monthly bill	$15.33 per month
C. Line Connection Pool share of Transmission component	$1.49 per month
D. Transformation Connection Pool share of Transmission component	$5.05 per month
E. Network Connection Pool share of Transmission component	$8.8 per month
F. Impact on Line Connection Pool Provincial Uniform Rates	0.00%
G. Impact on Transformation Connection Pool Provincial Uniform Rates	0.00%
H. Impact on Network Connection Pool Provincial Uniform Rates	6.33%
I. Increase in Transmission costs for typical monthly bill (E x H)	$0.56 per month or $6.68 per year
J. Net increase on typical residential customer bill (I / A)	0.41%

1 **Table 1 - Net Present Value, Page 1**

			In-Service Date	<------- Project year ended - annualized from In-Service Date -------->											
		Month	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15
		Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
			0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast															
Load Forecast (MW)				206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0
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
				206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0
Tariff Applied ($/kW/Month)				5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37
Incremental Revenue - $M				13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
Removal Costs - $M			(1.0)												
On-going OM&A Costs - $M			0.0	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
Municipal Tax - $M				(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)
Net Revenue/(Costs) before taxes - $M			(1.0)	10.1	10.1	10.1	10.1	10.1	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Income Taxes			0.3	4.4	15.9	19.5	17.7	16.1	14.7	13.3	12.0	10.9	9.8	8.8	7.9
Operating Cash Flow (after taxes) - $M			(0.7)	14.5	26.0	29.5	27.8	26.2	24.3	23.0	21.7	20.5	19.5	18.5	17.6
		Cumulative PV @ 5.65%													
PV Operating Cash Flow (after taxes) - $M	**(A)**	**263.7**	**(0.7)**	**14.1**	**23.9**	**25.8**	**22.9**	**20.4**	**18.0**	**16.1**	**14.4**	**12.9**	**11.5**	**10.4**	**9.3**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(643.7)												
- Overheads			(20.7)												
- AFUDC			(35.7)												
Total upfront capital expenditures			**(700.2)**												
On-going capital expenditures				0.0	(498.8)	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			(459.3)												
Total capital expenditures - $M			**(1,159.5)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**6.0**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	**(B)**	**(1,153.5)**	**(1,153.5)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(889.8)**	**(1,154.2)**	**(1,140.1)**	**(1,116.2)**	**(1,090.5)**	**(1,067.5)**	**(1,047.1)**	**(1,029.1)**	**(1,013.1)**	**(998.7)**	**(985.8)**	**(974.3)**	**(963.9)**	**(954.6)**

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**
Discount Rate - %		**5.65%**
		$M
PV Incremental Revenue		180.3
PV OM&A Costs		(17.5)
PV Municipal Tax		(31.2)
PV Income Taxes		(34.9)
PV CCA Tax Shield		173.0
PV Capital - Upfront	(700.2)	
Add: PV Capital Contribution	**0.0**	(700.2)
PV Capital - On-going		(459.3)
PV Working Capital		(0.0)
PV Surplus / (Shortfall)		(889.8)
Profitability Index*		**0.2**

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:	15-Dec-25
Payback Year:	2050
No. of years required for payback:	25

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Table 2 - Net Present Value, Page 2

		<------ Project year ended - annualized from In-Service Date ------>												
Month		Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15
Year		2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
		13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast														
Load Forecast (MW)		206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0
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
		206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0
Tariff Applied ($/kW/Month)		5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37
Incremental Revenue - $M		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
Removal Costs - $M														
On-going OM&A Costs - $M		(1.3)	(1.3)	(1.3)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)
Municipal Tax - $M		(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)
Net Revenue/(Costs) before taxes - $M		9.7	9.7	9.7	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Income Taxes		7.0	6.3	5.6	5.0	4.4	3.8	3.3	2.9	2.4	2.0	1.7	1.3	1.0
Operating Cash Flow (after taxes) - $M		16.7	16.0	15.2	14.4	13.8	13.3	12.8	12.3	11.9	11.5	11.1	10.8	10.5
PV Operating Cash Flow (after taxes) - $M	**(A)**	**8.4**	**7.6**	**6.9**	**6.2**	**5.6**	**5.1**	**4.6**	**4.2**	**3.9**	**3.5**	**3.2**	**3.0**	**2.7**
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)**	**(946.2)**	**(938.6)**	**(931.7)**	**(925.6)**	**(920.0)**	**(914.9)**	**(910.3)**	**(906.1)**	**(902.2)**	**(898.7)**	**(895.5)**	**(892.5)**	**(889.8)**

Table 3 - Revenue Requirement and Network Pool Rate Impact, Page 1

Waasigan Transmission Line			Project YE 15-Dec 2026	15-Dec 2027	15-Dec 2028	15-Dec 2029	15-Dec 2030	15-Dec 2031	15-Dec 2032	15-Dec 2033	15-Dec 2034	15-Dec 2035	15-Dec 2036	15-Dec 2037
Calculation of Incremental Revenue Requirement ($000)			1	2	3	4	5	6	7	8	9	10	11	12
In-service date	15-Dec-25			15-Dec-27										
Capital Cost	700,166			498,838										
Less: Capital Contribution Required	-			-										
Net Project Capital Cost	700,166			498,838										
Average Rate Base			355,296	936,738	1,151,478	1,128,666	1,105,855	1,083,044	1,060,232	1,037,421	1,014,609	991,798	968,987	946,175
Incremental OM&A Costs			882	882	882	882	882	1,301	1,301	1,301	1,301	1,301	1,301	1,301
Grants in Lieu of Municipal tax			2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300
Depreciation			13,309	22,811	22,811	22,811	22,811	22,811	22,811	22,811	22,811	22,811	22,811	22,811
Interest and Return on Rate Base			22,539	59,423	73,045	71,598	70,151	68,704	67,257	65,810	64,363	62,916	61,469	60,022
Income Tax Provision			-3	-4,409	-6,340	-4,239	-2,331	-600	967	2,385	3,664	4,817	5,853	6,781
REVENUE REQUIREMENT PRE-TAX			**39,028**	**81,008**	**92,699**	**93,353**	**93,814**	**94,516**	**94,637**	**94,607**	**94,440**	**94,145**	**93,734**	**93,215**
Incremental Revenue			13,278	13,278	13,278	13,278	13,278	13,278	13,278	13,278	13,278	13,278	13,278	13,278
SUFFICIENCY/(DEFICIENCY)			**-25,750**	**-67,729**	**-79,421**	**-80,075**	**-80,535**	**-81,238**	**-81,358**	**-81,329**	**-81,162**	**-80,867**	**-80,456**	**-79,937**
		Base Year												
Network Pool Revenue Requirement including sufficiency/(deficiency)		1,273,479	1,312,506	1,354,486	1,366,178	1,366,831	1,367,292	1,367,995	1,368,115	1,368,086	1,367,918	1,367,624	1,367,212	1,366,694
Network MW		237,084	239,556	239,556	239,556	239,556	239,556	239,556	239,556	239,556	239,556	239,556	239,556	239,556
Network Pool Rate ($/kw/month)		5.37	5.48	5.65	5.70	5.71	5.71	5.71	5.71	5.71	5.71	5.71	5.71	5.71
Increase/(Decrease) in Network Pool Rate ($/kw/month), relative to base year			0.11	0.28	0.33	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34
RATE IMPACT relative to base year			**2.05%**	**5.21%**	**6.15%**	**6.33%**	**6.33%**	**6.33%**	**6.33%**	**6.33%**	**6.33%**	**6.33%**	**6.33%**	**6.33%**

Assumptions		
Incremental OM&A		Using system average OM&A estimates for the station capital expenditures and 360 km of line connection facilities
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%	2023 federal and provincial corporate income tax rate
Capital Cost Allowance	8.00%	100% Class 47 assets except for Land

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

Waasigan Transmission Line		15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec
		2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Calculation of Incremental Revenue Requirement ($000)		13	14	15	16	17	18	19	20	21	22	23	24	25
In-service date	15-Dec-25													
Capital Cost	700,166													
Less: Capital Contribution Required	-													
Net Project Capital Cost	700,166													
Average Rate Base		923,364	900,553	877,741	854,930	832,118	809,307	786,496	763,684	740,873	718,062	695,250	672,439	649,628
Incremental OM&A Costs		1,301	1,301	1,301	1,510	1,510	1,510	1,510	1,510	1,510	1,510	1,510	1,510	1,510
Grants in Lieu of Municipal tax		2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300
Depreciation		22,811	22,811	22,811	22,811	22,811	22,811	22,811	22,811	22,811	22,811	22,811	22,811	22,811
Interest and Return on Rate Base		58,575	57,127	55,680	54,233	52,786	51,339	49,892	48,445	46,998	45,551	44,104	42,657	41,210
Income Tax Provision		7,610	8,349	9,003	9,581	10,088	10,529	10,911	11,237	11,513	11,742	11,928	12,075	12,185
REVENUE REQUIREMENT PRE-TAX		**92,597**	**91,889**	**91,096**	**90,436**	**89,496**	**88,490**	**87,425**	**86,304**	**85,133**	**83,915**	**82,654**	**81,354**	**80,017**
Incremental Revenue		13,278	13,278	13,278	13,278	13,278	13,278	13,278	13,278	13,278	13,278	13,278	13,278	13,278
SUFFICIENCY/(DEFICIENCY)		**-79,319**	**-78,610**	**-77,818**	**-77,158**	**-76,218**	**-75,212**	**-74,147**	**-73,026**	**-71,855**	**-70,637**	**-69,376**	**-68,076**	**-66,739**
	Base Year													
Network Pool Revenue Requirement including sufficiency/(deficiency)	1,273,479	1,366,076	1,365,367	1,364,575	1,363,915	1,362,974	1,361,969	1,360,904	1,359,783	1,358,612	1,357,394	1,356,133	1,354,832	1,353,495
Network MW	237,084	239,556	239,556	239,556	239,556	239,556	239,556	239,556	239,556	239,556	239,556	239,556	239,556	239,556
Network Pool Rate ($/kw/month)	5.37	5.70	5.70	5.70	5.69	5.69	5.69	5.68	5.68	5.67	5.67	5.66	5.66	5.65
Increase/(Decrease) in Network Pool Rate ($/kw/month), relative to base year		0.33	0.33	0.33	0.32	0.32	0.32	0.31	0.31	0.30	0.30	0.29	0.29	0.28
RATE IMPACT relative to base year		**6.15%**	**6.15%**	**6.15%**	**5.96%**	**5.96%**	**5.96%**	**5.77%**	**5.77%**	**5.59%**	**5.59%**	**5.40%**	**5.40%**	**5.21%**

1 **Table 5 - DCF Assumptions**

Hydro One Networks -- Transmission Connection Economic Evaluation Model
2023 Parameters and Assumptions

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

Monthly Rate ($ per kW)	
Network	**5.37**
Transformation	**2.98**
Line	**0.88**

Grants in lieu of Municipal tax (% of up-front capital expenditure, a proxy for property value):		**0.33%**	Based on Transmission system average
Income taxes:			
Basic Federal Tax Rate - % of taxable income:	2023	**15.00%**	Current rate
Ontario corporation income tax - % of taxable income:	2023	**11.50%**	Current rate
Capital Cost Allowance Rate:			
Class 47 costs	2023	**8%**	Current rate
Decision Support defined costs (1)	2023	**0%**	
Decision Support defined costs (2)	2023	**0%**	
Decision Support defined costs (3)	2023	**0%**	
After-tax Discount rate:		**5.65%**	Based on OEB-approved ROE of 9.36% on common equity and 4.79% on short-term debt, 4.3% forecast cost of long-term debt and 40/60 equity/debt split, and current enacted income tax rate of 26.5%

REVENUE REQUIREMENT INFORMATION AND REGULATORY ACCOUNT REQUESTS

1.0 REVENUE REQUIREMENT INFORMATION

No project capital expenditures or in-service rate base additions are included in Hydro One's OEB-approved 2023-27 transmission rate application (EB-2021-0110) for the Waasigan Project. However, in that rate application's evidence, namely the TSP (Section 2.1.3), Hydro One disclosed that the Project's line scope was expected to be owned by, and included in, the rate base of a new future OEB-transmission licensed partnership, while Project station cost will be in-serviced into Hydro One's transmission rate base.

<u>Station Costs</u>

The primary reason for not including capital expenditures and an in-service rate base forecast in the 2023-27 rate filing at that time of submission was due to the level of uncertainty regarding the timing of Phase 2 of the Project combined with the preliminary nature of the project's development, in-service timing, and cost estimate maturity. However, the OEB approved the EDWR Account allowing Hydro One to capture the annual revenue requirement amounts for in-serviced assets in Hydro One's rate base, for disposition in a future transmission revenue requirement application.

To qualify for the EDWR Account, the Project's need must be driven by external organizations, such as Government and/or regulatory bodies and/or IESO direction. The EDWR Account will be used to record the Project's station incremental annual revenue requirement once each Project phase has been in-serviced, prior to the assets being included in the opening rate base of Hydro One's future 2028-32 rate application[1].

[1] The primary reason for the creation of this regulatory account is to reduce the impact of unplanned occurrences and the need for major capital redirections from Hydro One's OEB-approved capital envelope such that it does not impact the planned sustainment/refurbishment portfolio of work, as submitted, supported and approved in Hydro One's current TSP.

<u>Lines Costs</u>

Like the Stations costs, during construction, all transmission line project costs will be tracked in Hydro One's OEB-approved ATP Account.

The ATP Account provides cost recovery protection to Hydro One, in the event that this Project is not completed or in-serviced for reasons that are beyond the management and control of Hydro One.

The OEB established the ATP Account for Hydro One to record costs for projects which are the subject of an OIC, have direction from the Minister of Energy and/or a letter from the IESO. Line projects recorded in the ATP Account are expected to be owned by and included in the rate base of a new partnership between Hydro One and one or more partners (i.e., are not expected to be included in a future Hydro One revenue requirement application).

In approving the ATP Account the OEB noted that the, "key advantage of this approach is that Hydro One's financial records are separated from those involving partnerships with other entities."[2] and that, "the use of the ATP Account for what will likely be unplanned, high cost, long timeline projects will avoid having Hydro One re-prioritize its own capital program to accommodate these projects. This re-prioritization could have negative consequences for Hydro One's ability to maintain the reliability and integrity of its assets."[3]

2.0 REGULATORY ACCOUNT INFORMATION

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

[2] EB-2021-0169, Decision and Order, October 7, 2021. Pgs.7-8
[3] EB-2021-0169, Decision and Order, October 7, 2021. Pg. 8

1 **PROJECT SCHEDULE**

TASK	START	FINISH
Leave to Construct Approval	July 31, 2023	Feb 2024
PHASE 1 - LINES		
Detailed Engineering	March 2023	December 2023
Receipt of non-OEB key permits and approvals (MNRF, Railway, Pipeline, Water Crossing, etc.)	March 2024	June 2024
Completion of Property Right Acquisition	July 2023	September 2025
Major Material Ordered	July 2023	December 2023
Construction	March 2024	October 2025
Commissioning	October 2025	December 2025
In Service		December 2025
Completion of site remediation	July 2025	June 2026
PHASE 1 - STATIONS		
Completion of detailed Engineering	July 2023	April 2024
Major Material Ordered	August 2023	January 2024
Construction	July 2024	August 2025
Commissioning	April 2025	December 2025
In Service		December 2025
Completion of site remediation	January 2026	May 2026
PHASE 2 - LINES		
Receipt of non-OEB key permits and approvals (MNRF, Railway, Pipeline,	March 2024	January 2026

Water Crossing, etc.)		
Completion of Property Right Acquisition	July 2023	September 2025
Completion of detailed Engineering	July 2023	January 2024
Major Material Ordered	July 2023	December 2023
Construction	January 2026	October 2027
Commissioning	October 2027	December 2027
In Service		December 2027
Completion of site remediation	July 2027	July 2028
PHASE 2 - STATIONS		
Completion of detailed Engineering	July 2023	April 2024
Major Material Ordered	August 2023	January 2024
Construction	April 2026	June 2027
Commissioning	July 2027	December 2027
In Service		December 2027
Completion of site remediation	January 2028	May 2028

1.0 STATUS OF THE PROJECT ENVIRONMENTAL APPROVAL PROCESS

On March 8, 2022, Hydro One distributed the Notice of Commencement of the EA to Indigenous communities, government officials/agencies, interested persons and organizations, signifying the start of the EA, which will be executed per the approved amended EA Terms of Reference. Since that time, Hydro One has continued to engage with Indigenous communities, stakeholders, and members of the public.

A comprehensive environmental field survey program was undertaken which collected data along the alternative transmission line routes to help inform the evaluation and selection of a preferred route, as well as the assessment of its project footprint. The Project team worked closely with Indigenous communities to ensure that their involvement in the field surveys was encouraged and that opportunities to share indigenous knowledge during field surveys was possible.

2.0 PROJECT IMPACT ON NEIGHBOURING TRANSMITTERS

Upper Canada 2, operating as EWT Partnership, is a neighbouring transmitter to Hydro One at Lakehead TS. EWT Partnership has two 230 kV transmission circuits terminating at Hydro One's Lakehead TS. Phase 1 of the Project requires EWT Partnership's M37L circuit to be re-terminated into a new switching position at the station, for reliability purposes. The final line span, which will be owned by Hydro One, between EWT Partnership's last line structure and the station will be modified to make the re-termination. Based on preliminary analysis, EWT Partnership will need to modify their last line structure to support the new requirements of this line's span. The existing skywire and protection and control systems are not expected to be affected. Upon re-termination, commissioning will be completed. All work will be conducted on existing property rights, and no additional approvals, such as environmental approvals, are expected. The Phase 1 schedule assumes that the system operator, the IESO, will permit outage(s) for this re-termination. The M37L circuit is one of four 230 kV circuits along the interface. Hydro One will continue to coordinate with the neighbouring transmitter and the IESO to facilitate the re-termination work for the 230 kV EWT interface.

Watay Power is another transmitter that has facilities located in the same region as the Project. Their facilities are included in the CIA study for the purpose of communicating updated short circuit levels, and there will be no material impact on the Watay Power transmission system.

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DESCRIPTIONS OF THE PHYSICAL DESIGN

1.0 LINE FACILITIES

Details of Proposed Line Facilities

Hydro One is proposing to build a new double circuit 230 kV transmission line between Lakehead TS and Mackenzie TS (the Project's Phase 1) and a new single circuit 230 kV transmission line between Mackenzie TS and Dryden TS (the Project's Phase 2). The new line primarily involves using steel lattice structures, which is described in more detail below.

2.0 ROUTE DESCRIPTION

The Waasigan Project is in northwestern Ontario in the Thunder Bay and Rainy River districts near the communities of Shuniah, Thunder Bay, Atikokan and Dryden. The Project's Phase 1 double circuit line will run from the existing Lakehead TS to Mackenzie TS, and the Project's Phase 2 single circuit line will run from the existing Mackenzie TS to Dryden TS. The Project's transmission line path will utilize a 46m wide ROW that is approximately 360km in length, which comprises of two sections that are further outlined below.

2.1 ROUTE DETAILS

Project Phase 1 Description: Double Circuit 230 kV.

i. The Project route for this double circuit 230 kV portion of the Project starts at Lakehead TS in the municipality of Shuniah located adjacent to Highway 11/17, approximately 20km northeast of Thunder Bay. The transmission line exits north from the TS for 0.5km and then heads west paralleling the south side of Highway 11/17 for approximately 2km.

ii. The transmission line crosses north over Highway 11/17 and continues west paralleling the existing 230 kV transmission line for 3km before crossing over Highway 527. The transmission line continues west paralleling the south side of the existing 230 kV transmission line for 32km and then crosses over the Kaministiquia River.

iii. The transmission line then travels west along the south side of the existing 230kV for 23.5km until it crosses Highway 17 and then another 28.5 km until it crosses Highway 11. From thereit turns north for 0.1km to cross the existing 230 kV before turning west for 1km paralleling north of the existing 230 kV and 115 kV transmission lines and crossing a section of Amp Lake. The line then turns southwest for 0.7km and crosses the two existing transmission lines and another portion of Amp Lake.

iv. The transmission line then turns west and continues west paralleling the south side of the existing 230 kV transmission line for 47km, crossing Highway 11 four times.

v. The transmission line then crosses the existing 115 kV transmission line and Highway 11 before continuing for another 51km where it crosses Highway 11 twice. The line then heads north for 0.2km, crossing the existing transmission lines, then running 0.7km west into Mackenzie TS in Atikokan, crossing Highway 11B.

Project Phase 2 Description: Single Circuit 230 kV

i. From Mackenzie TS, the Project route for the single-circuit 230 kV transmission line portion crosses east over Highway 11B and continues east for 0.5km before heading southeast for approximately 0.2km and crossing the existing 44 kV and 115 kV transmission lines. The line then parallels the south side of the existing 115 kV transmission line and crosses Atikokan River turning north for 2km before crossing the existing 44 kV and 115 kV transmission lines and Highway 622.

ii. The transmission line then parallels the west side of the existing transmission line for 14km before crossing Highway 622 again. The line continues to parallel the west side of the existing 115 kV transmission line for 2km before crossing the existing 115 kV transmission line and then continuing for another 86km, crossing the Campus Lake Conservation Reserve and the Turtle River-White Otter Lake Provincial Park. After crossing Highway 17, the line continues to parallel the west side of the existing 230 kV and 115 kV transmission lines for 50km, crossing Highway 72.

iii. The transmission line then turns east to cross the existing 230 kV and 115 kV transmission lines and continues along the north side of the existing transmission lines for 15km, crossing Highway 601 and Highway 665. The line then turns south for 0.2km crossing the existing 230 kV transmission line and then turns west for 0.1km to cross the existing 230 kV and 115 kV transmission lines. The line then turns south and continues into Dryden TS in the City of Dryden.

iv. Separation of 0.8km of existing 230 kV F25A and D26A circuits to ensure they do not share common structures over a distance that exceeds 1.6 km. Comment if new ROW or on existing ROW; this was part of IESO's scope.

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

3.0 LINE DESCRIPTION

The transmission line will have two circuits between Lakehead TS and Mackenzie TS, and one circuit between Mackenzie TS and Dryden TS. It is comprised of 795 kcmil ACSR. There are two OPGW 96 strand fibre cables for the double circuit line Phase 1 Project, between Lakehead TS and Mackenzie TS. For the single circuit line Phase 2 Project between Mackenzie TS and Dryden TS, these is one OPGW 96 fibre cable. Additionally, the transmission line will have the following attributes:

i. The line will have a continuous ampacity of 1160A (summer 35C);
ii. Glass insulators will be used for both suspension and tension applications in accordance with Hydro One standards;
iii. The line will use Stockbridge-type vibration dampers;
iv. Typical structure foundations will be Helical Pile type; and
v. The line will make use of the 159 self-supported lattice towers with nominal spans of 350m (figure 1). There will also be 10 H-frame structures used to cross other transmission lines (figure 2).

Detailed drawings of the types of towers Hydro One expects to be used along the Project route are provided at **Attachment 1** to this Exhibit.

4.0 STATION WORK

PHASE 1

Lakehead TS

The transmission station work will consist of the following:

1. Extend H and P Buses into the West 230 kV yard and space provision for future H and P Bus Tie Breakers.
2. Addition of one new 230 kV diameter with four new breakers and associated disconnect switches in the West 230 kV yard.
3. Re-terminate an existing 230 kV circuit towards Marathon to the new diameter in the West 230 kV yard for reliability purposes.
4. Terminate one of the new 230 kV circuits towards Mackenzie TS onto the existing diameter.
5. Terminate the second new 230 kV circuit towards Mackenzie TS onto the new diameter in the 230 kV West Yard.
6. Addition of two new 230 kV line disconnect switches and two new 230 kV ground switches for the new 230 kV circuit pair towards Mackenzie TS.
7. Addition of one 40 MVAR shunt reactor with associated facilities (breaker, disconnect switch, etc.) to be connected onto the new 230 kV diameter in the 230 kV West Yard.

Mackenzie TS

The transmission station work will consist of the following:

1. Reconfiguration of the existing 230 kV ring bus into a two-bus, three-diameter arrangement, with the new diameter consisting of three new breakers and associated disconnect switches (Phase 1 scope), and provisioning for the fourth 230 kV breaker (Phase 2 scope) & new 230 kV Mackenzie TS x Dryden TS 230 kV line termination (Phase 2 scope) on the new diameter.
2. Addition of two new breakers and associated disconnect switches on the existing diameter.

3. Re-terminate the existing 230 kV circuit towards Fort Frances on the same diameter for reliability purposes.
4. Terminate one of the new 230 kV circuits towards Lakehead TS onto the existing diameter.
5. Terminate the second new 230 kV circuit towards Lakehead TS onto the new diameter.
6. Re-terminate the existing 230 kV circuit towards Dryden TS from the H Bus onto the new diameter for reliability purposes.
7. Install two new 230 kV line disconnect switches and ground switches for new 230 kV circuits terminating from Lakehead TS.
8. Addition of two 40 MVAR shunt reactors with associated facilities (switching breaker, disconnect switch, etc.).

PHASE 2

Mackenzie TS

The transmission station work will consist of the following:

1. Addition of one new 230 kV breaker and associated disconnect switches on the new diameter.
2. Terminate the new 230 kV circuit towards Dryden TS onto the new diameter, along with one new 230 kV line disconnect switch and one new ground switch.

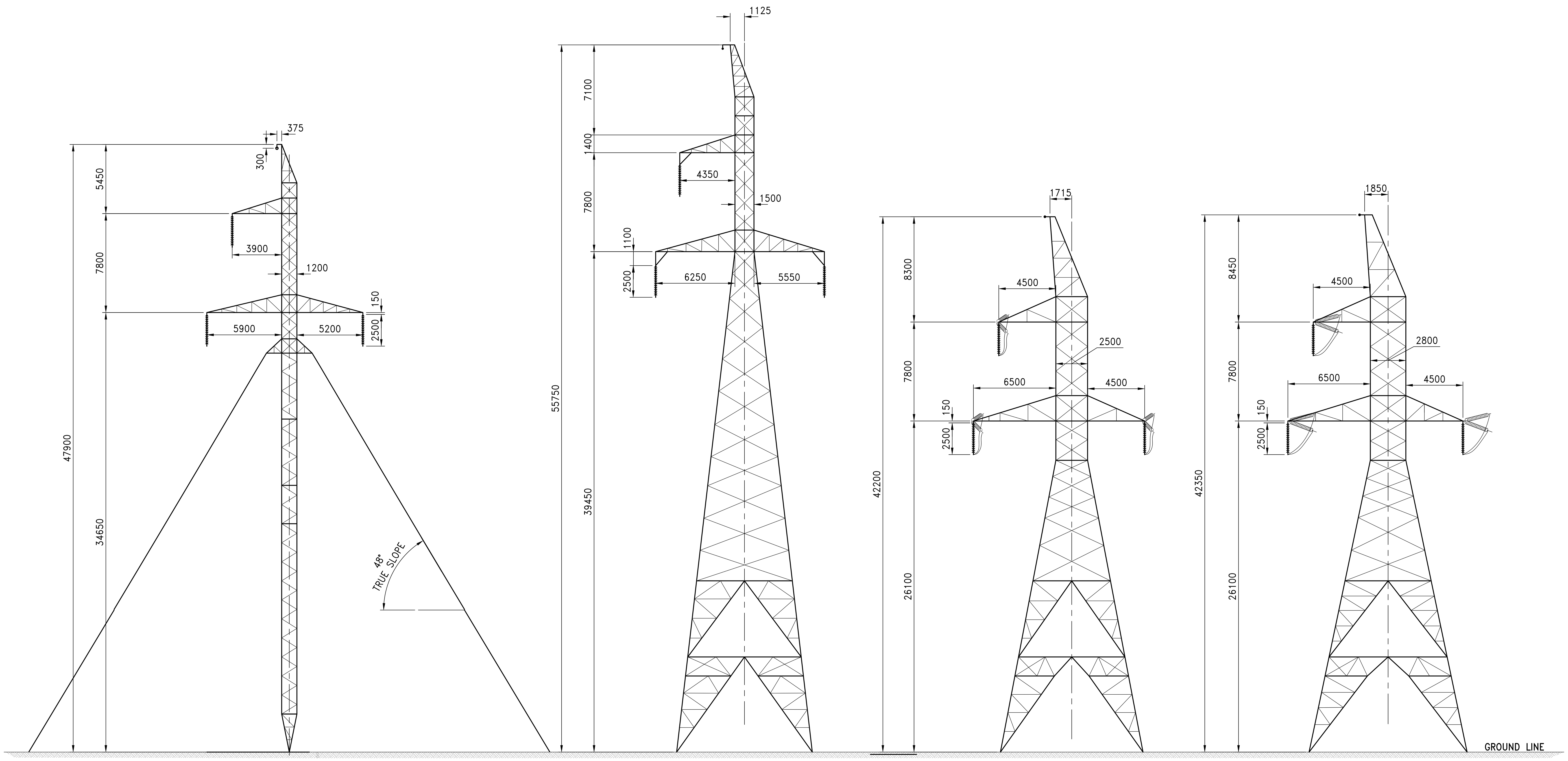
Dryden TS

The transmission station work will consist of the following:

1. Reconfiguration of the existing Ring Bus to include two new 230 kV breakers and associated disconnect switches, and provision of space for two additional breakers for future scope.
2. Re-terminate the 230/115 kV autotransformer (nomenclature T22) onto the new diameter.
3. Terminate the new circuit towards Mackenzie TS onto the new diameter, along with associated line disconnect switch and ground switch for the new circuit.

4. Provision space for one reactive compensation device with associated facilities, such as switching breaker, disconnect switch, etc., on Bus 2 based on IESO's Phase 2 Letter of Direction.

TOWER DESIGN ALONG ROUTE



A1–GT
TANGENT (0–2°)

Tower Type	Tower Extension	Tower Weight kg	Tower Weight lbs	Structure Total Height m
A1-GT	A1-GT+0.0E	4243	9356	29.9
	A1-GT+1.5E	4428	9764	31.4
	A1-GT+3.0E	4571	10079	32.9
	A1-GT+4.5E	4712	10390	34.4
	A1-GT+6.0E	4854	10703	35.9
	A1-GT+7.5E	5019	11067	37.4
	A1-GT+9.0E	5142	11338	38.9
	A1-GT+10.5E	5269	11618	40.4
	A1-GT+12.0E	5392	11889	41.9
	A1-GT+13.5E	5512	12154	43.4
	A1-GT+15.0E	5632	12419	44.9
	A1-GT+16.5E	5752	12683	46.4
	A1-GT+18.0E	5872	12948	47.9

A1–L
LIGHT ANGLE (0–15°)

Tower Type	Tower Extension	Tower Weight kg	Tower Weight lbs	Structure Total Height m
A1-L	A1-L+0.0BE+3.0+3.0+3.0+3.0	7880	17375	37.75
	A1-L+0.0BE+4.0+4.0+4.0+4.0	8045	17739	38.75
	A1-L+0.0BE+5.0+5.0+5.0+5.0	8267	18229	39.75
	A1-L+0.0BE+6.0+6.0+6.0+6.0	8530	18809	40.75
	A1-L+0.0BE+7.0+7.0+7.0+7.0	8752	19298	41.75
	A1-L+0.0BE+8.0+8.0+8.0+8.0	9006	19858	42.75
	A1-L+0.0BE+9.0+9.0+9.0+9.0	9310	20529	43.75
	A1-L+7.5BE+3.0+3.0+3.0+3.0	10889	24010	45.25
	A1-L+7.5BE+4.0+4.0+4.0+4.0	11058	24383	46.25
	A1-L+7.5BE+5.0+5.0+5.0+5.0	11278	24868	47.25
	A1-L+7.5BE+6.0+6.0+6.0+6.0	11536	25437	48.25
	A1-L+7.5BE+7.0+7.0+7.0+7.0	11768	25948	49.25
	A1-L+7.5BE+8.0+8.0+8.0+8.0	12014	26491	50.25
	A1-L+7.5BE+9.0+9.0+9.0+9.0	12314	27152	51.25
	A1-L+12.0BE+3.0+3.0+3.0+3.0	12106	26694	49.75
	A1-L+12.0BE+4.0+4.0+4.0+4.0	12267	27049	50.75
	A1-L+12.0BE+5.0+5.0+5.0+5.0	12485	27529	51.75
	A1-L+12.0BE+6.0+6.0+6.0+6.0	12752	28118	52.75
	A1-L+12.0BE+7.0+7.0+7.0+7.0	12971	28601	53.75
	A1-L+12.0BE+8.0+8.0+8.0+8.0	13222	29155	54.75
	A1-L+12.0BE+9.0+9.0+9.0+9.0	13523	29818	55.75

A1–M
MEDIUM ANGLE (0°–45°)

Tower Type	Tower Extension	Tower Weight kg	Tower Weight lbs	Structure Total Height m
A1-M	A1-M+0.0BE+3.0+3.0+3.0+3.0	8540	18831	28.7
	A1-M+0.0BE+4.0+4.0+4.0+4.0	8829	19468	29.7
	A1-M+0.0BE+5.0+5.0+5.0+5.0	9152	20180	30.7
	A1-M+0.0BE+6.0+6.0+6.0+6.0	9479	20901	31.7
	A1-M+0.0BE+7.0+7.0+7.0+7.0	9917	21867	32.7
	A1-M+0.0BE+8.0+8.0+8.0+8.0	10347	22815	33.7
	A1-M+0.0BE+9.0+9.0+9.0+9.0	10859	23944	34.7
	A1-M+7.5BE+3.0+3.0+3.0+3.0	11657	25704	36.2
	A1-M+7.5BE+4.0+4.0+4.0+4.0	11938	26323	37.2
	A1-M+7.5BE+5.0+5.0+5.0+5.0	12266	27047	38.2
	A1-M+7.5BE+6.0+6.0+6.0+6.0	12594	27770	39.2
	A1-M+7.5BE+7.0+7.0+7.0+7.0	13031	28733	40.2
	A1-M+7.5BE+8.0+8.0+8.0+8.0	13460	29679	41.2
	A1-M+7.5BE+9.0+9.0+9.0+9.0	13974	30813	42.2

A1–H
HEAVY ANGLE (45°–60°)

Tower Type	Tower Extension	Tower Weight kg	Tower Weight lbs	Structure Total Height m
A1-H	A1-H+0.0BE+3.0+3.0+3.0+3.0	9262	20423	28.85
	A1-H+0.0BE+4.0+4.0+4.0+4.0	9609	21188	29.85
	A1-H+0.0BE+5.0+5.0+5.0+5.0	9934	21904	30.85
	A1-H+0.0BE+6.0+6.0+6.0+6.0	10150	22381	31.85
	A1-H+0.0BE+7.0+7.0+7.0+7.0	10496	23144	32.85
	A1-H+0.0BE+8.0+8.0+8.0+8.0	10741	23684	33.85
	A1-H+0.0BE+9.0+9.0+9.0+9.0	11107	24491	34.85
	A1-H+7.5BE+3.0+3.0+3.0+3.0	13194	29093	36.35
	A1-H+7.5BE+4.0+4.0+4.0+4.0	13537	29849	37.35
	A1-H+7.5BE+5.0+5.0+5.0+5.0	13859	30559	38.35
	A1-H+7.5BE+6.0+6.0+6.0+6.0	14081	31049	39.35
	A1-H+7.5BE+7.0+7.0+7.0+7.0	14419	31794	40.35
	A1-H+7.5BE+8.0+8.0+8.0+8.0	14661	32328	41.35
	A1-H+7.5BE+9.0+9.0+9.0+9.0	15038	33159	42.35

NOTES:
1. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED.

REV	REVISION REMARKS
3	ISSUED FOR IFCR
2	ISSUED FOR RFP
1	ISSUED FOR FINAL CLIENT REVIEW #1
0	ISSUED FOR REVIEW

hydro one

NOT FOR CONSTRUCTION

ASSET NAME: WAISIGAN

ASSET NO.

TITLE: 230kV SINGLE CIRCUIT A1 TOWER FAMILY OUTLINE DRAWING

AR NO. | PID NO. | DATE YYYY/MM/DD: 2023/01/23 | SCALE: NTS

REF. ENGINEERING STANDARD | REF. MODEL/STANDARD DWG. NO. | REV. NO.

DRAWN BY: G. DECASTRO | DRAWING CHECKED BY:

DESIGNED BY: N. LEE | DESIGN APPROVED BY: A. RAO

DRAWING NO.: DP-03-05-0001 | SHEET NO.: 01 | REV NO.: 3

CONSULTANT: PHASOR ENGINEERING INC. A QUANTA SERVICES COMPANY | CONTRACT NO.

CLASS

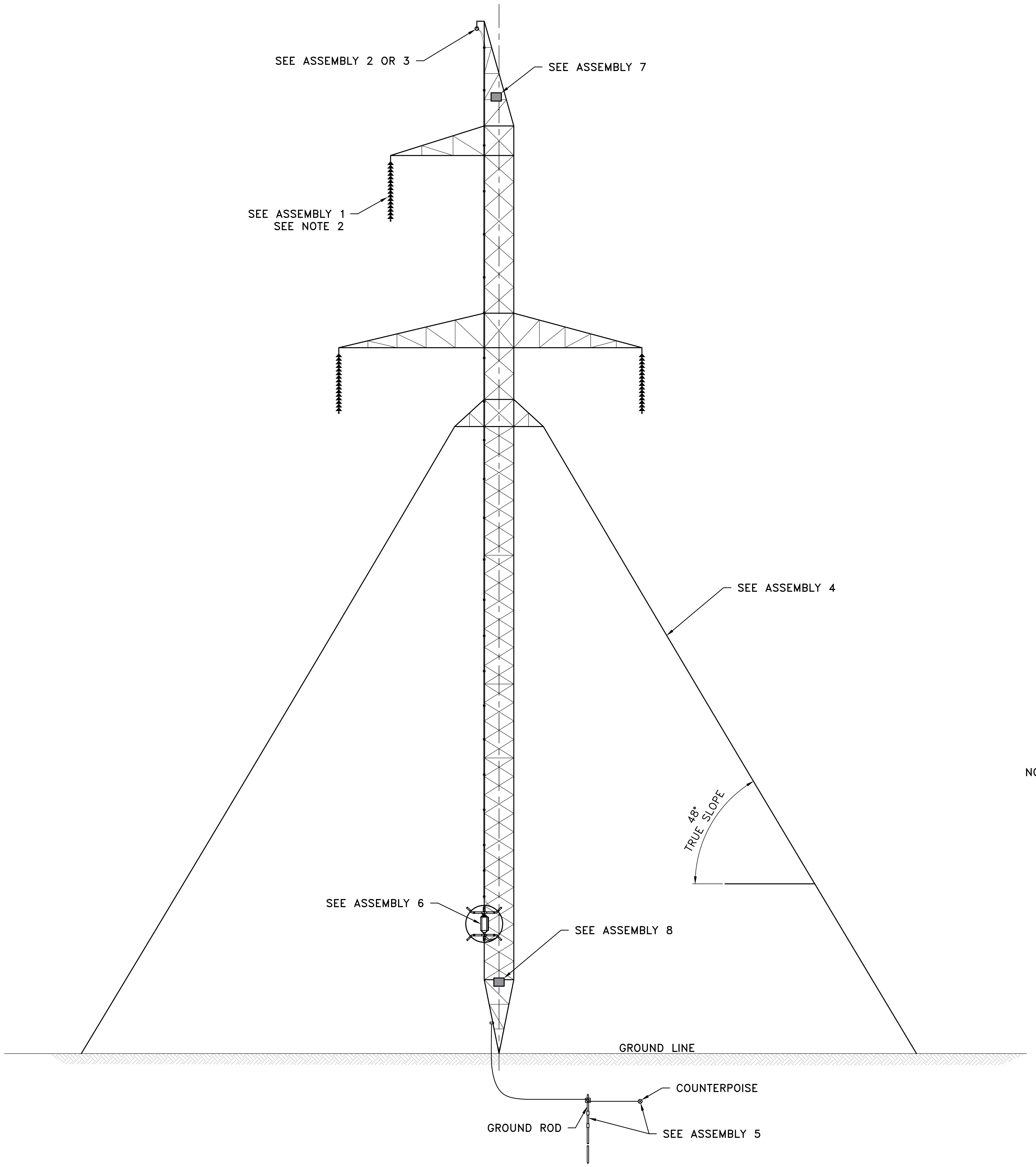
A1 (594 x 841)

millimetres 0 10 50 100 200 250 300

TITLE BLOCK REV 10 - FEBRUARY 2020

LIST OF ASSEMBLIES			
ASSEMBLY NO.	QUANTITY	DESCRIPTION	REFERENCE DRAWING
1	3	230KV SUSPENSION ASSEMBLY SINGLE STRING ASSEMBLY S1	DP-05-04-0001 or 0003A
2	1	OPGW SUSPENSION ASSEMBLY SINGLE CIRCUIT OPGW-SC-S	DP-05-04-0011
3	2	OPGW DEADEND ASSEMBLY WITH SPLICE SINGLE CIRCUIT OPGW-SC-DE-SPLICE	DP-05-04-0015
4	4	SINGLE CIRCUIT GUY ANCHOR ASSEMBLY (5/8")	DP-05-04-0020
5	1	GROUNDING DRAWING SUSPENSION STRUCTURES GROUNDING-S	DP-09-02-0002
6	1	OPGW SPLICE BOX OPGW-BOX	DP-05-04-0019
7	1	AERIAL NUMBER BOARD SIGNAGE	DP-07-02-0005
8	2	DANGER SIGN SIGNAGE - 2	DP-07-02-0006

SEE NOTE 2



NOTES:
1. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED.
2. USE DOUBLE STRING ASSEMBLY FOR CRITICAL CROSSING TOWERS.

REV	REVISION REMARKS
3	ISSUED FOR IFCR
2	ISSUED FOR RFP
1	ISSUED FOR FINAL CLIENT REVIEW #1
0	ISSUED FOR REVIEW

hydro one

NOT FOR CONSTRUCTION

ASSET NAME: WAASIGAN
ASSET NO.:

TITLE: 230kV SINGLE CIRCUIT GUYED TANGENT A1-GT STEEL LATTICE TOWER OUTLINE DRAWING

AR NO.: | PID NO.: | DATE YYYY/MM/DD: 2023/01/23 | SCALE: NTS

REF. ENGINEERING STANDARD: | REF. MODEL/STANDARD DWG. NO.: | REV. NO.:

DRAWN BY: G. DECASTRO | DRAWING CHECKED BY:

DESIGNED BY: N. LEE | DESIGN APPROVED BY: A. RAO

DRAWING NO.: DP-03-05-0002 | SHEET NO.: 01 | REV NO.: 3

CONSULTANT: PHASOR ENGINEERING INC. A QUANTA SERVICES COMPANY

CONTRACT NO.:

CLASS

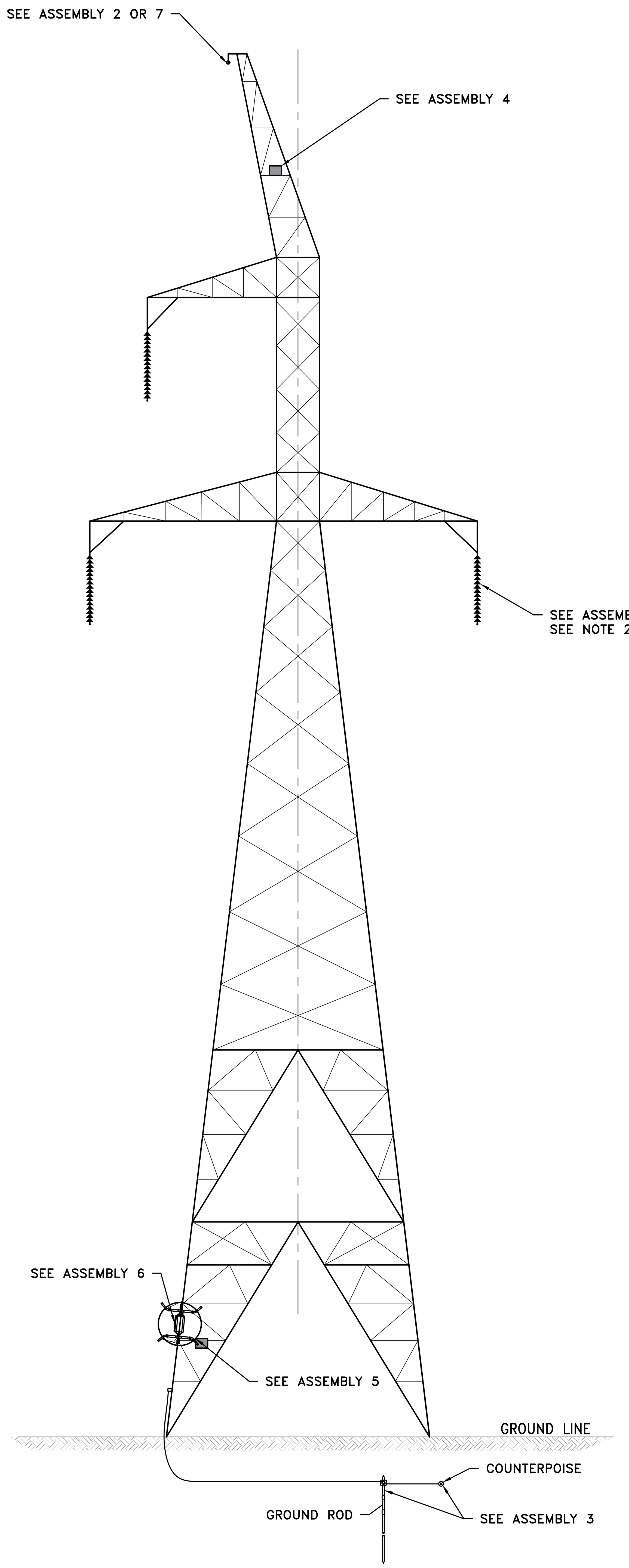
A1 (594 x 841)

millimetres 0 10 50 100 200 250 300

TITLE BLOCK REV 10 - FEBRUARY 2020

LIST OF ASSEMBLIES			
ASSEMBLY NO.	QUANTITY	DESCRIPTION	REFERENCE DRAWING
1	3	230KV LIGHT ANGLE ASSEMBLY SINGLE STRING L1	DP-05-04-0002 OR 0003B
2	1	OPGW SUSPENSION ASSEMBLY SINGLE CIRCUIT OPGW-SC-S	DP-05-04-0011
3	1	GROUNDING DRAWING SUSPENSION STRUCTURES GROUNDING-S	DP-09-02-0002
4	1	AERIAL NUMBER BOARD SIGNAGE-1	DP-07-02-0005
5	2	DANGER SIGN SIGNAGE-2	DP-07-02-0006
6	1	OPGW SPLICE BOX OPGW-BOX	DP-05-04-0019
7	2	OPGW DEADEND ASSEMBLY WITH SPLICE SINGLE CIRCUIT OPGW-SC-DE-SPLICE	DP-05-04-0015

SEE NOTE 2



NOTES:
1. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED.
2. USE DOUBLE STRING ASSEMBLY FOR CRITICAL CROSSING TOWERS.

REV	REVISION REMARKS
3	ISSUED FOR IFCR
2	ISSUED FOR RFP
1	ISSUED FOR FINAL CLIENT REVIEW #1
0	PRELIMINARY DESIGN

hydro one

NOT FOR CONSTRUCTION

ASSET NAME: WAASIGAN
ASSET NO.:

TITLE: 230kV SINGLE CIRCUIT LIGHT ANGLE A1-L (0-15°) STEEL LATTICE TOWER OUTLINE

AR NO.: | PID NO.: | DATE YYYY/MM/DD: 2023/01/23 | SCALE: NTS

REF. ENGINEERING STANDARD: | REF. MODEL/STANDARD DWG. NO.: | REV. NO.:

DRAWN BY: G. DECASTRO | DRAWING CHECKED BY:

DESIGNED BY: N. LEE | DESIGN APPROVED BY: A. RAO

DRAWING NO.: DP-03-05-0003 | SHEET NO.: 01 | REV NO.: 3

CONSULTANT: PHASOR ENGINEERING INC — A QUANTA SERVICES COMPANY | CONTRACT NO.:

CLASS

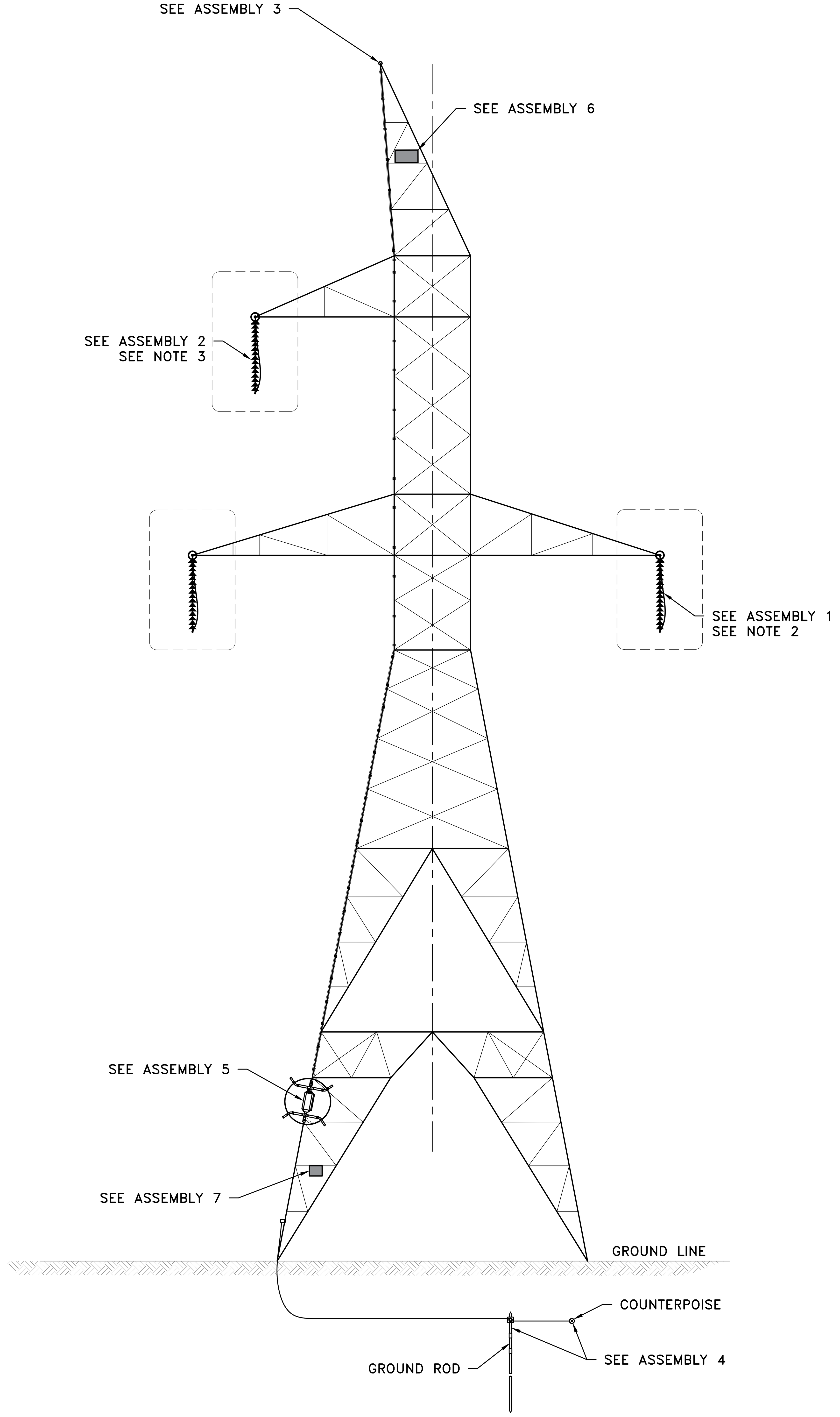
A1 (594 x 841)

millimetres 0 10 50 100 200 250 300

TITLE BLOCK REV 10 - FEBRUARY 2020

LIST OF ASSEMBLIES			
ASSEMBLY NO.	QUANTITY	DESCRIPTION	REFERENCE DRAWING
1	6	230KV DEADEND ASSEMBLY SINGLE STRING D1	DP-05-04-0004 OR DP-05-04-0006
*2	VARIES	230KV SUSPENSION ASSEMBLY SINGLE STRING S1	DP-05-04-0001
3	2	OPGW DEADEND ASSEMBLY WITH SPLICE SINGLE CIRCUIT OPGW-SC-DE-SPLICE	DP-05-04-0015
4	1	GROUNDING DRAWING DEADEND STRUCTURES GROUNDING DE	DP-09-02-0001
5	1	OPGW SPLICE BOX OPGW-BOX	DP-05-04-0019
6	1	AERIAL NUMBER BOARD SIGNAGE-1	DP-07-02-0005
7	2	DANGER SIGN SIGNAGE-2	DP-07-02-0006

* SEE NOTE 3



NOTES:
1. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED.
2. USE DOUBLE STRING ASSEMBLY FOR CRITICAL CROSSING TOWERS, ASSEMBLY DP-05-04-0006.
3. CONFIGURATION OF ASSEMBLY 2 WILL BE DEPENDENT ON CHART BELOW.

ANGLE (DEG)	ASSEMBLY COUNT
>30-<45	4

REV	REVISION REMARKS
3	ISSUED FOR IFCR
2	ISSUED FOR RFP
1	ISSUED FOR FINAL CLIENT REVIEW #1
0	ISSUED FOR REVIEW

hydro one

NOT FOR CONSTRUCTION

ASSET NAME: WAASIGAN

ASSET NO.

TITLE: 230kV SINGLE CIRCUIT MEDIUM ANGLE A1-MR (0°-45°) STEEL LATTICE TOWER OUTLINE DRAWING

AR NO. | PID NO. | DATE YYYY/MM/DD: 2023/01/23 | SCALE: NTS

REF. ENGINEERING STANDARD | REF. MODEL/STANDARD DWG. NO. | REV. NO.

DRAWN BY: G. DECASTRO | DRAWING CHECKED BY:

DESIGNED BY: C. HENDERSON | DESIGN APPROVED BY: A. RAO

DRAWING NO.: DP-03-05-0004 | SHEET NO.: 01 | REV NO.: 3

CONSULTANT: PHASOR ENGINEERING INC | CONTRACT NO.

CLASS

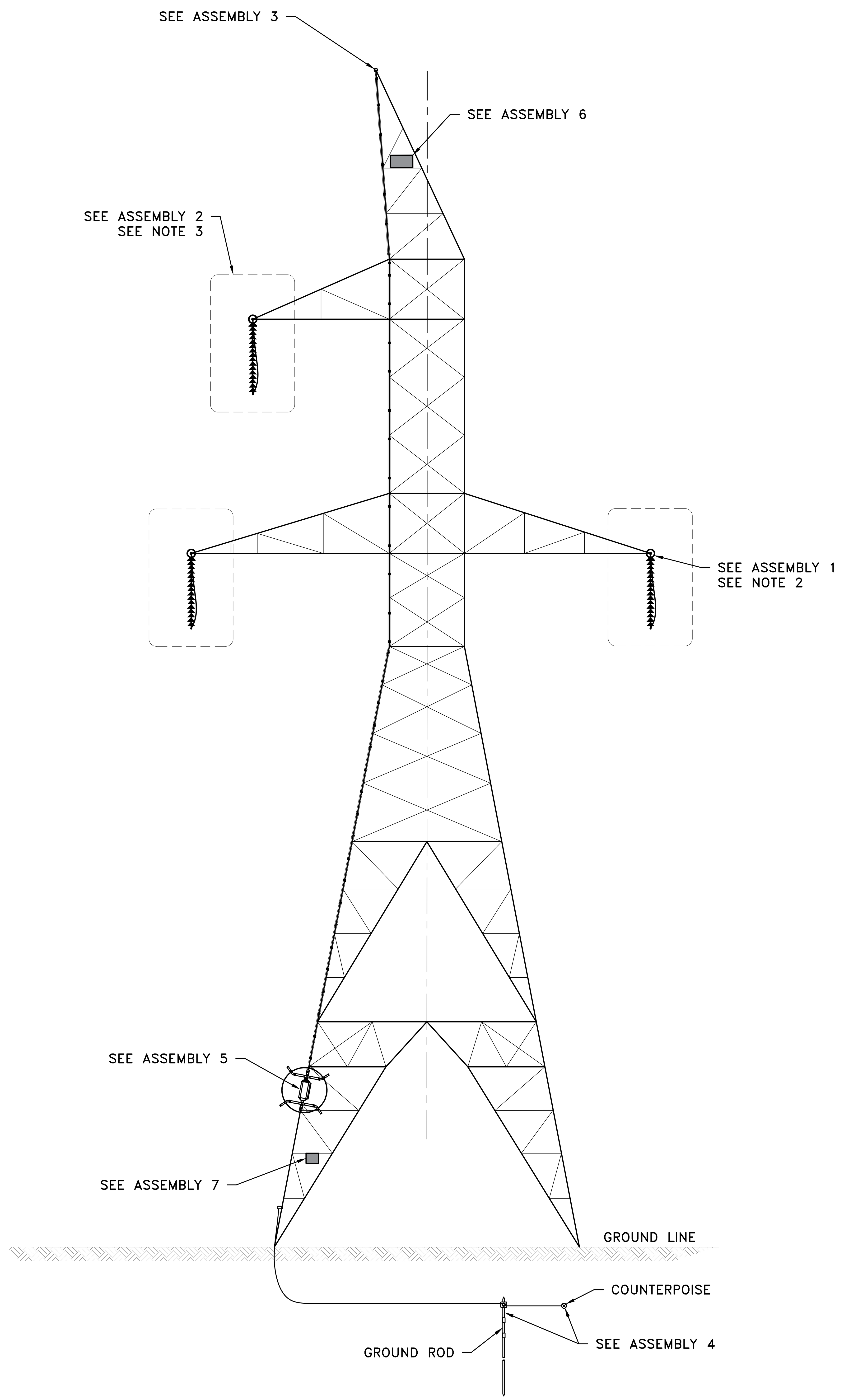
TITLE BLOCK REV 10 - FEBRUARY 2020

A1 (594 x 841)

millimetres 0 10 50 100 200 250 300

LIST OF ASSEMBLIES			
ASSEMBLY NO.	QUANTITY	DESCRIPTION	REFERENCE DRAWING
1	6	230KV DEADEND ASSEMBLY SINGLE STRING D1	DP-05-04-0004 OR DP-05-04-0006
*2	VARIES	230KV SUSPENSION ASSEMBLY SINGLE STRING S1	DP-05-04-0001
3	2	OPGW DEADEND ASSEMBLY WITH SPLICE SINGLE CIRCUIT OPGW-SC-DE-SPLICE	DP-05-04-0015
4	1	GROUNDING DRAWING DEADEND STRUCTURES GROUNDING DE	DP-09-02-0001
5	1	OPGW SPLICE BOX OPGW-BOX	DP-05-04-0019
6	1	AERIAL NUMBER BOARD SIGNAGE-1	DP-07-02-0005
7	2	DANGER SIGN SIGNAGE-2	DP-07-02-0006

* SEE NOTE 3



NOTES:
1. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED.
2. USE DOUBLE STRING ASSEMBLY FOR CRITICAL CROSSING TOWERS, ASSEMBLY DP-05-04-0006.
3. CONFIGURATION OF ASSEMBLY 2 WILL BE DEPENDENT ON CHART BELOW.

ANGLE (DEG)	ASSEMBLY COUNT
>30-<45	4

REV	REVISION REMARKS
1	ISSUED FOR IFCR
0	ISSUED FOR RFP

hydro one

NOT FOR CONSTRUCTION

ASSET NAME: WAASIGAN
ASSET NO.:

TITLE: 230kV SINGLE CIRCUIT MEDIUM ANGLE A1-ML (0°-45°) STEEL LATTICE TOWER OUTLINE DRAWING

AR NO.:
PID NO.:
DATE YYYY/MM/DD: 2023/01/23
SCALE: NTS
REF. ENGINEERING STANDARD:
REF. MODEL/STANDARD DWG. NO.:
REV. NO.:
DRAWN BY: B. MURRAY
DRAWING CHECKED BY:
DESIGNED BY: C. HENDERSON
DESIGN APPROVED BY: A. RAO
DRAWING NO.: DP-03-05-0004
SHEET NO.: 02
REV NO.: 1
CONSULTANT: PHASOR ENGINEERING INC. A QUANTA SERVICES COMPANY
CONTRACT NO.:

CLASS

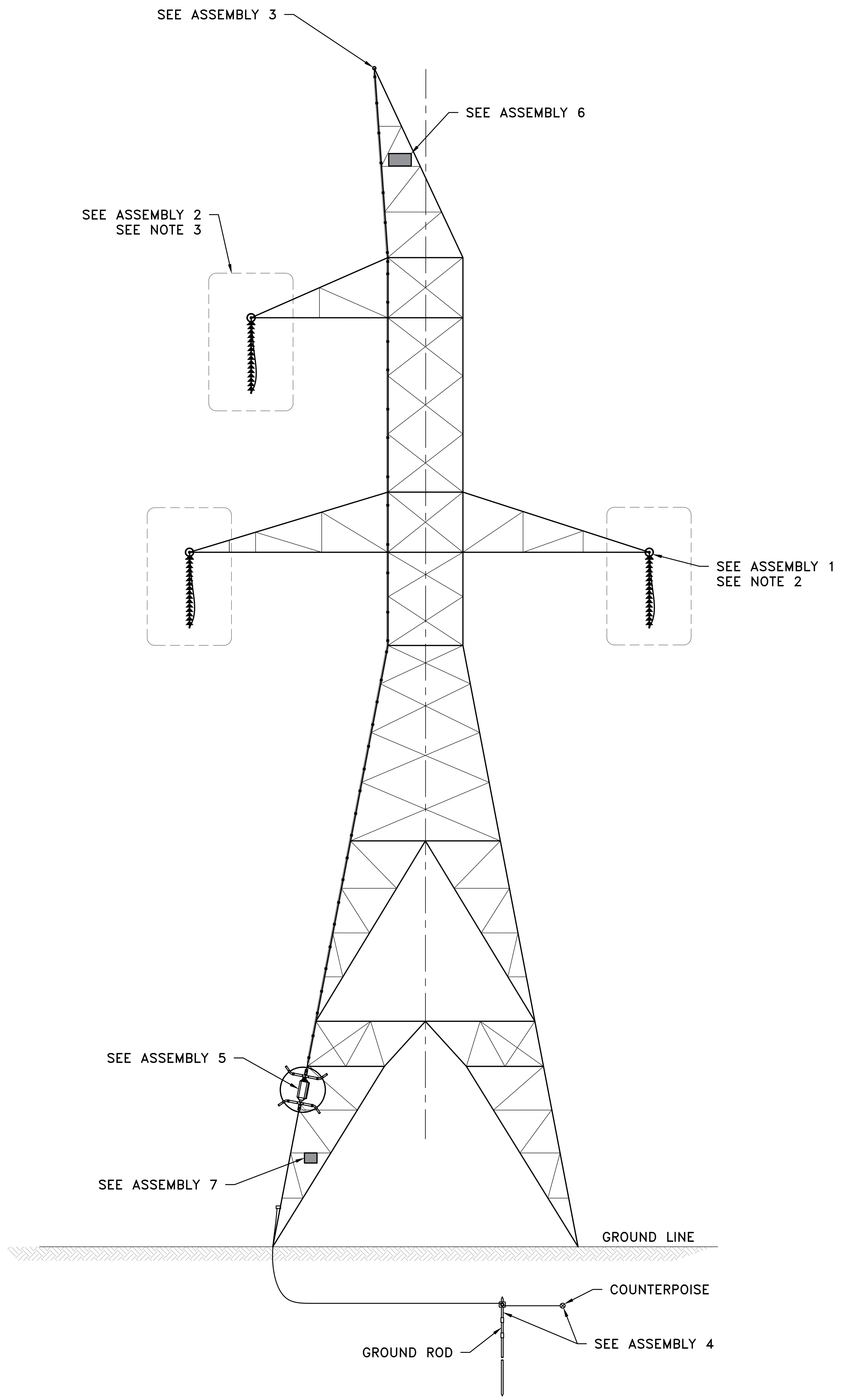
TITLE BLOCK REV 10 - FEBRUARY 2020

A1 (594 x 841)

millimetres 0 10 50 100 200 250 300

LIST OF ASSEMBLIES			
ASSEMBLY NO.	QUANTITY	DESCRIPTION	REFERENCE DRAWING
1	6	230KV DEADEND ASSEMBLY SINGLE STRING D1	DP-05-04-0004 OR DP-05-04-0006
*2	VARIES	230KV SUSPENSION ASSEMBLY SINGLE STRING S1	DP-05-04-0001
3	2	OPGW DEADEND ASSEMBLY WITH SPLICE SINGLE CIRCUIT OPGW-SC-DE-SPLICE	DP-05-04-0015
4	1	GROUNDING DRAWING DEADEND STRUCTURES GROUNDING DE	DP-09-02-0001
5	1	OPGW SPLICE BOX OPGW-BOX	DP-05-04-0019
6	1	AERIAL NUMBER BOARD SIGNAGE-1	DP-07-02-0005
7	2	DANGER SIGN SIGNAGE-2	DP-07-02-0006

* SEE NOTE 3



NOTES:
1. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED.
2. USE DOUBLE STRING ASSEMBLY FOR CRITICAL CROSSING TOWERS, ASSEMBLY DP-05-04-0006.
3. CONFIGURATION OF ASSEMBLY 2 WILL BE DEPENDENT ON CHART BELOW.

ANGLE (DEG)	ASSEMBLY COUNT
>30-<45	4

REV	REVISION REMARKS
0	ISSUED FOR IFCR

hydro one

NOT FOR CONSTRUCTION

ASSET NAME: WAASIGAN

TITLE: 230kV SINGLE CIRCUIT MEDIUM ANGLE A1-MC (0°-45°) STEEL LATTICE TOWER OUTLINE DRAWING

DATE YYYY/MM/DD: 2023/02/13 | SCALE: NTS

DRAWN BY: G. DECASTRO
DESIGNED BY: N. LEE
DESIGN APPROVED BY: A. RAO

DRAWING NO.: DP-03-05-0004 | SHEET NO.: 03 | REV NO.: 1

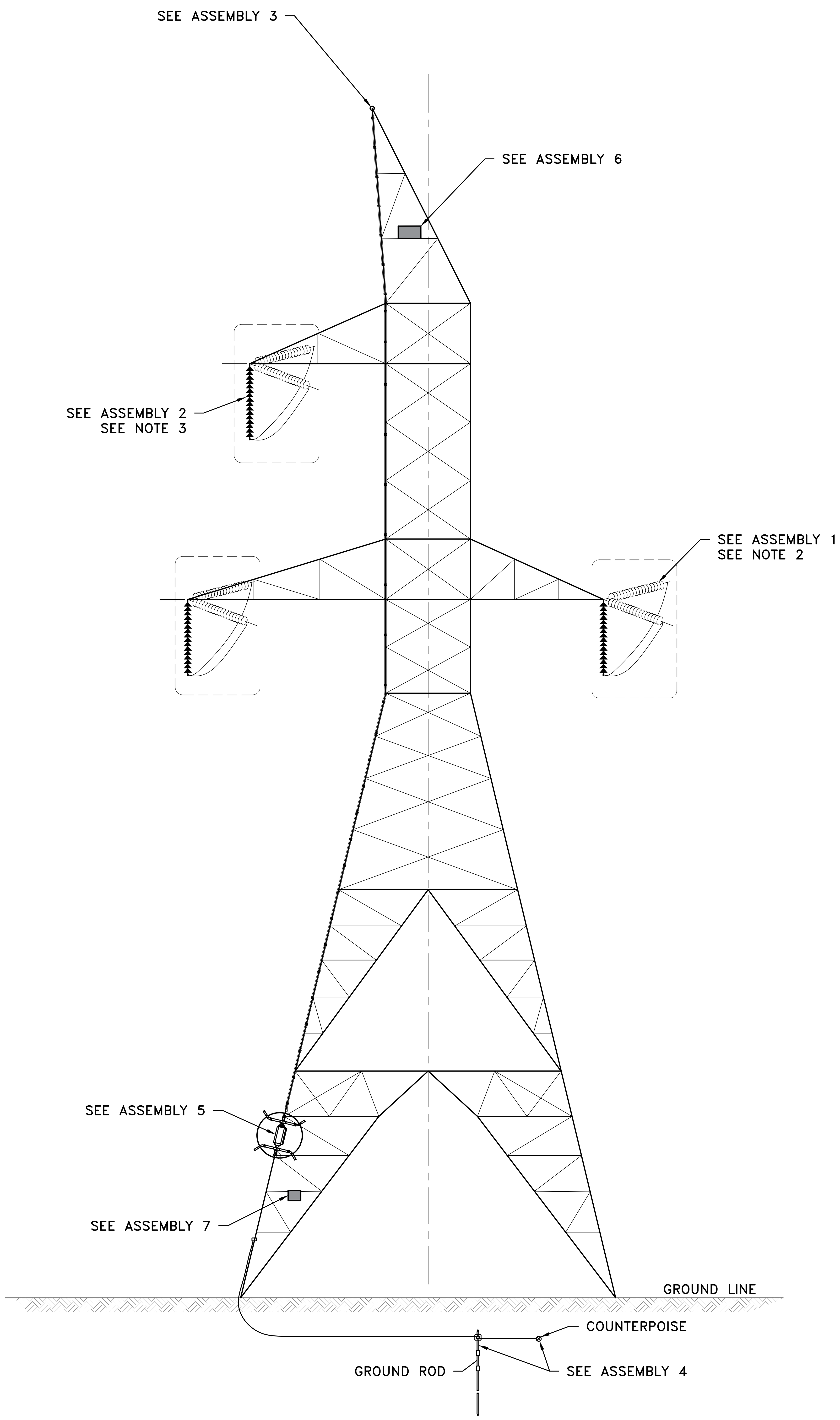
CONSULTANT: PHASOR ENGINEERING INC

CLASS

A1 (594 x 841)

TITLE BLOCK REV 10 - FEBRUARY 2020

LIST OF ASSEMBLIES			
ASSEMBLY NO.	QUANTITY	DESCRIPTION	REFERENCE DRAWING
1	6	230KV DEADEND ASSEMBLY SINGLE STRING D1	DP-05-04-0004 OR DP-05-04-0006
2	5	230KV SUSPENSION ASSEMBLY SINGLE STRING S1	DP-05-04-0001
3	2	OPGW DEADEND ASSEMBLY WITH SPLICE SINGLE CIRCUIT OPGW-SC-DE-SPLICE	DP-05-04-0015
4	1	GROUNDING DRAWING DEADEND STRUCTURES GROUNDING DE	DP-09-02-0001
5	1	OPGW SPLICE BOX OPGW-BOX	DP-05-04-0019
6	1	AERIAL NUMBER BOARD SIGNAGE-1	DP-07-02-0005
7	2	DANGER SIGN SIGNAGE-2	DP-07-02-0006



NOTES:
1. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED.
2. USE DOUBLE STRING ASSEMBLY FOR CRITICAL CROSSING TOWERS, ASSEMBLY DP-05-04-0006.

REV	REVISION REMARKS
3	ISSUED FOR IFCR
2	ISSUED FOR RFP
1	ISSUED FOR FINAL CLIENT REVIEW #1
0	ISSUED FOR REVIEW

hydro one

NOT FOR CONSTRUCTION

ASSET NAME: WAASIGAN
ASSET NO.:

TITLE: 230kV SINGLE CIRCUIT HEAVY ANGLE STRAIN A1-HR (45°-60°) STEEL LATTICE TOWER OUTLINE DRAWING

AR NO.: | PID NO.: | DATE YYYY/MM/DD: 2023/01/23 | SCALE: NTS

REF. ENGINEERING STANDARD: | REF. MODEL/STANDARD DWG. NO.: | REV. NO.:

DRAWN BY: G. DECASTRO | DRAWING CHECKED BY:

DESIGNED BY: C. HENDERSON | DESIGN APPROVED BY: A. RAO

DRAWING NO.: DP-03-05-0005 | SHEET NO.: 01 | REV NO.: 3

CONSULTANT: PHASOR ENGINEERING INC | CONTRACT NO.:

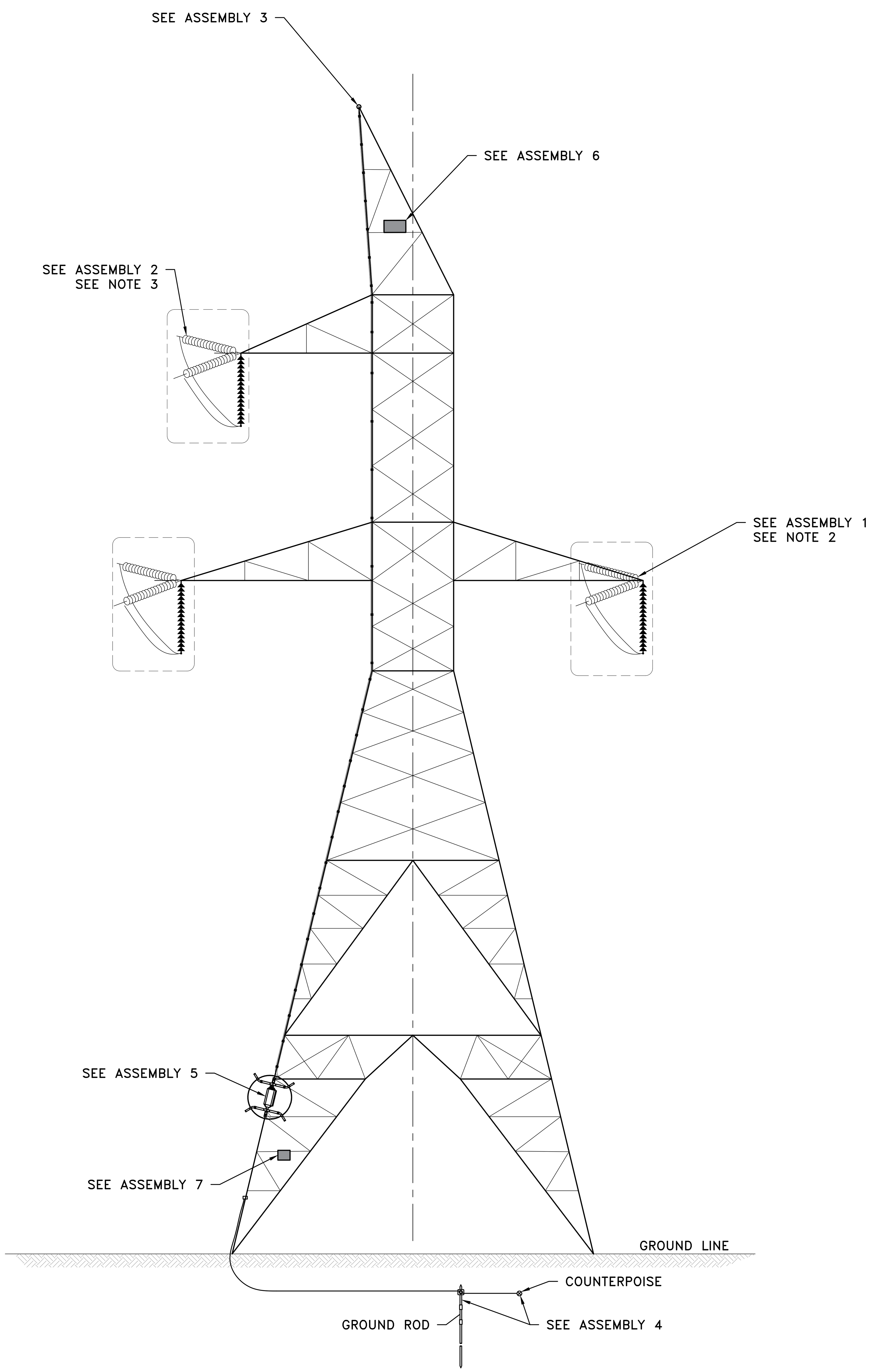
CLASS

A1 (594 x 841)

millimetres 0 10 50 100 200 250 300

TITLE BLOCK REV 10 - FEBRUARY 2020

LIST OF ASSEMBLIES			
ASSEMBLY NO.	QUANTITY	DESCRIPTION	REFERENCE DRAWING
1	6	230KV DEADEND ASSEMBLY SINGLE STRING D1	DP-05-04-0004 OR DP-05-04-0006
2	4	230KV SUSPENSION ASSEMBLY SINGLE STRING S1	DP-05-04-0001
3	2	OPGW DEADEND ASSEMBLY WITH SPLICE SINGLE CIRCUIT OPGW-SC-DE-SPLICE	DP-05-04-0015
4	1	GROUNDING DRAWING DEADEND STRUCTURES GROUNDING DE	DP-09-02-0001
5	1	OPGW SPLICE BOX OPGW-BOX	DP-05-04-0019
6	1	AERIAL NUMBER BOARD SIGNAGE-1	DP-07-02-0005
7	2	DANGER SIGN SIGNAGE-2	DP-07-02-0006



NOTES:
1. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED.
2. USE DOUBLE STRING ASSEMBLY FOR CRITICAL CROSSING TOWERS, ASSEMBLY DP-05-04-0006.

REV	REVISION REMARKS
1	ISSUED FOR IFCR
0	ISSUED FOR RFP

hydro one

NOT FOR CONSTRUCTION

ASSET NAME: WAASIGAN
ASSET NO.:

TITLE: 230kV SINGLE CIRCUIT HEAVY ANGLE STRAIN A1-HL (45°-60°) STEEL LATTICE TOWER OUTLINE DRAWING

AR NO.: | PID NO.: | DATE YYYY/MM/DD: 2023/01/23 | SCALE: NTS

REF. ENGINEERING STANDARD: | REF. MODEL/STANDARD DWG. NO.: | REV. NO.:

DRAWN BY: B. MURRAY | DRAWING CHECKED BY:

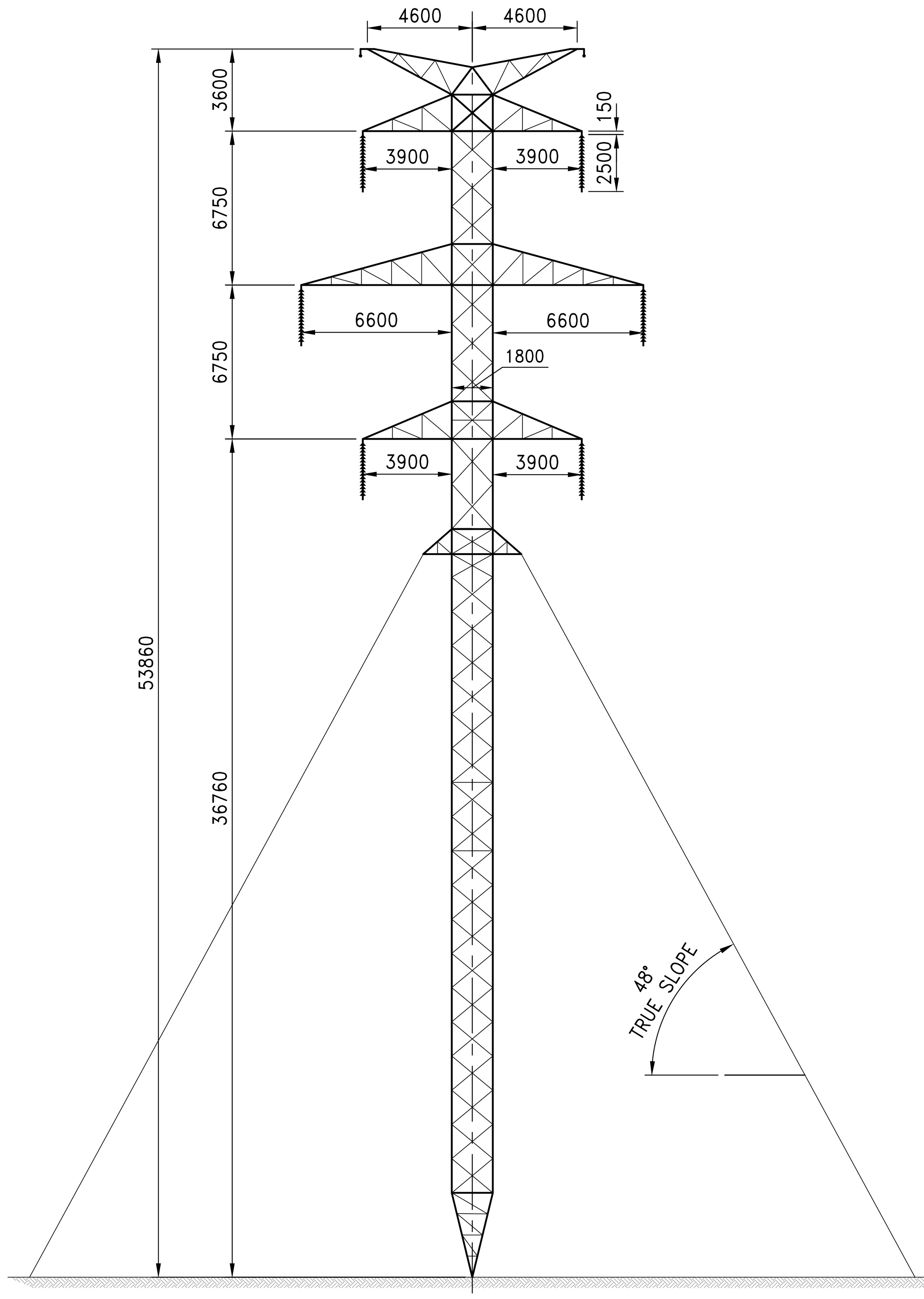
DESIGNED BY: C. HENDERSON | DESIGN APPROVED BY: A. RAO

DRAWING NO.: DP-03-05-0005 | SHEET NO.: 02 | REV NO.: 1

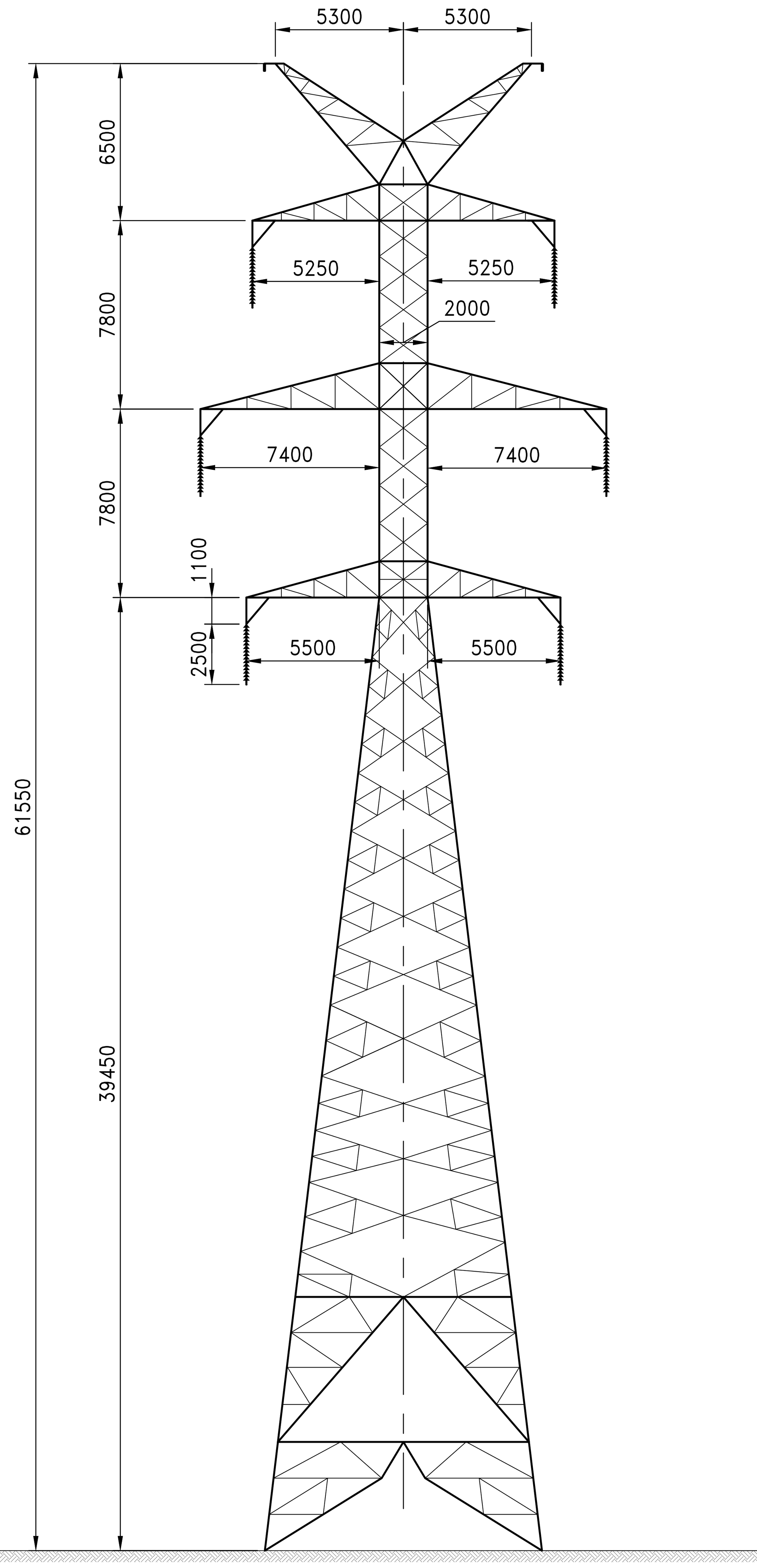
CONSULTANT: PHASOR ENGINEERING INC. A QUANTA SERVICES COMPANY | CONTRACT NO.:

CLASS

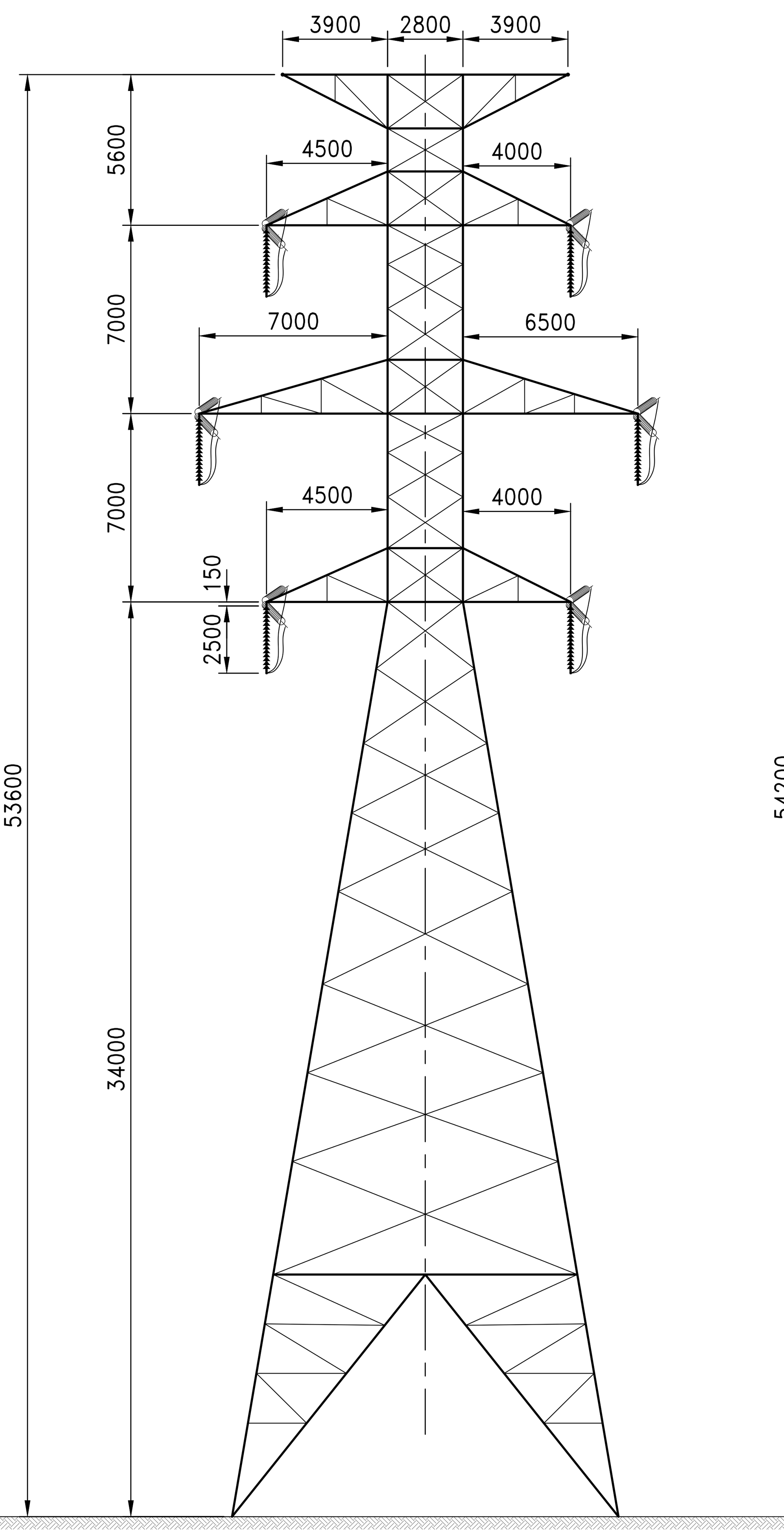
millimetres 0 10 50 100 200 250 300



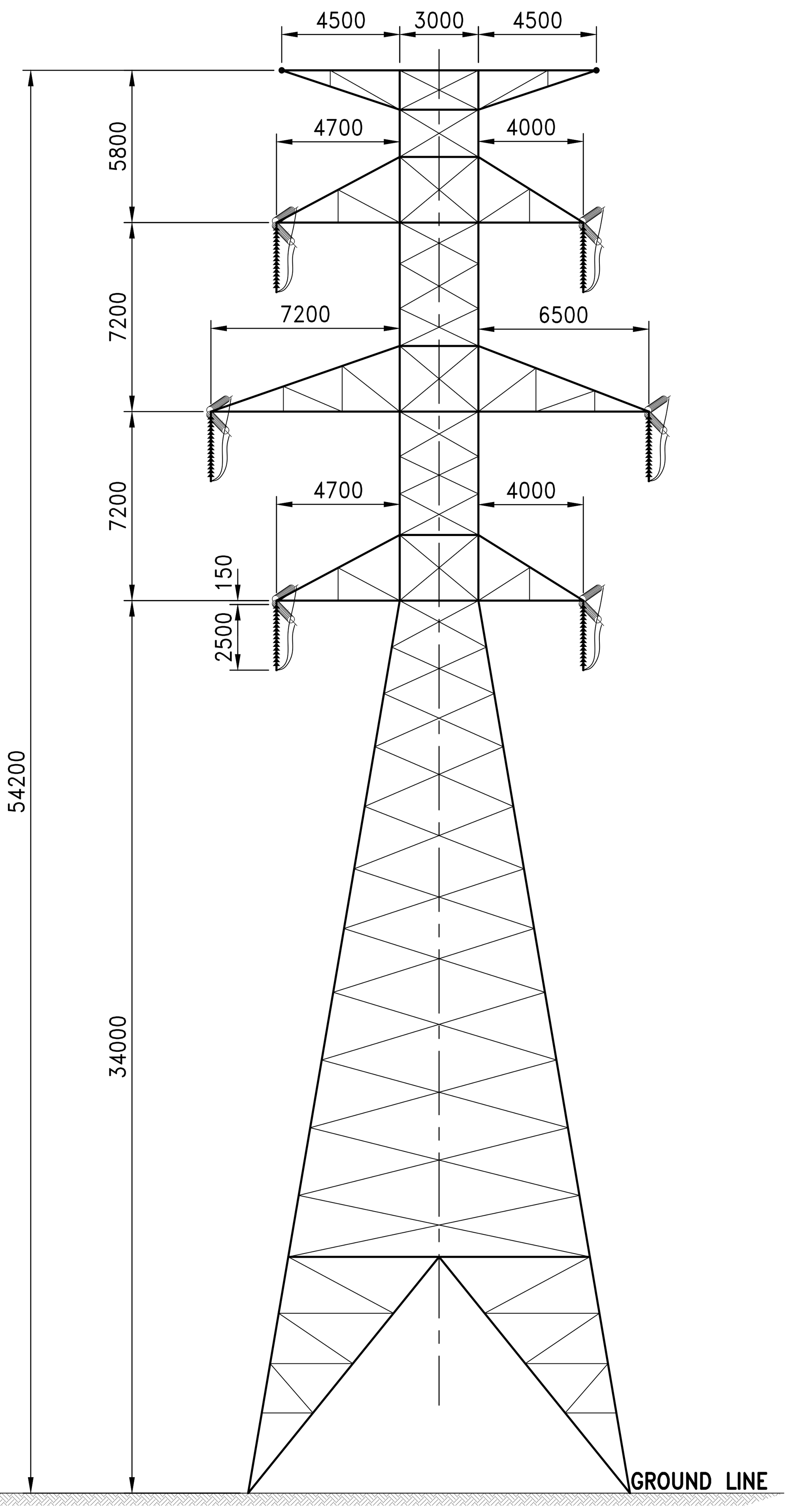
C2-GT
TANGENT (0-2°)



C2-L
LIGHT ANGLE (0-15°)



C2-M
MEDIUM ANGLE (0°-45°)



C2-H
HEAVY ANGLE (45°-60°)

Tower Type	Tower Extension	Tower Weight kg	Tower Weight lbs	Structure Total Height m
C2-GT	C2-GT+0.0E	7965	17563	35.86
	C2-GT+1.5E	8325	18357	37.36
	C2-GT+3.0E	8425	18577	38.86
	C2-GT+4.5E	8606	18976	40.36
	C2-GT+6.0E	8880	19580	41.86
	C2-GT+7.5E	9139	20151	43.36
	C2-GT+9.0E	9343	20601	44.86
	C2-GT+10.5E	9525	21003	46.36
	C2-GT+12.0E	9793	21594	47.86
	C2-GT+13.5E	10009	22070	47.86
	C2-GT+15.0E	10225	22546	47.86
	C2-GT+16.5E	10441	23022	47.86
	C2-GT+18.0E	10658	23501	53.86

Tower Type	Tower Extension	Tower Weight kg	Tower Weight lbs	Structure Total Height m
C2-L	C2-L+0.0BE+3.0+3.0+3.0+3.0	14017	30907	43.55
	C2-L+0.0BE+4.0+4.0+4.0+4.0	14429	31816	44.55
	C2-L+0.0BE+5.0+5.0+5.0+5.0	14613	32222	45.55
	C2-L+0.0BE+6.0+6.0+6.0+6.0	14862	32771	46.55
	C2-L+0.0BE+7.0+7.0+7.0+7.0	15280	33692	47.55
	C2-L+0.0BE+8.0+8.0+8.0+8.0	15647	34502	48.55
	C2-L+0.0BE+9.0+9.0+9.0+9.0	15923	35110	49.55
	C2-L+7.5BE+3.0+3.0+3.0+3.0	17748	39134	51.05
	C2-L+7.5BE+4.0+4.0+4.0+4.0	18157	40036	52.05
	C2-L+7.5BE+5.0+5.0+5.0+5.0	18347	40455	53.05
	C2-L+7.5BE+6.0+6.0+6.0+6.0	18597	41006	54.05
	C2-L+7.5BE+7.0+7.0+7.0+7.0	19010	41917	55.05
	C2-L+7.5BE+8.0+8.0+8.0+8.0	19383	42740	56.05
	C2-L+7.5BE+9.0+9.0+9.0+9.0	19658	43346	57.05
	C2-L+12.0BE+3.0+3.0+3.0+3.0	19310	42579	55.55
	C2-L+12.0BE+4.0+4.0+4.0+4.0	19728	43500	56.55
	C2-L+12.0BE+5.0+5.0+5.0+5.0	19918	43919	57.55
	C2-L+12.0BE+6.0+6.0+6.0+6.0	20172	44479	58.55
	C2-L+12.0BE+7.0+7.0+7.0+7.0	20584	45388	59.55
	C2-L+12.0BE+8.0+8.0+8.0+8.0	20954	46204	60.55
	C2-L+12.0BE+9.0+9.0+9.0+9.0	21226	46803	61.55

Tower Type	Tower Extension	Tower Weight kg	Tower Weight lbs	Structure Total Height m
C2-M	C2-M+0.0BE+3.0+3.0+3.0+3.0	22704	50062	40.10
	C2-M+0.0BE+4.0+4.0+4.0+4.0	22538	49696	41.10
	C2-M+0.0BE+5.0+5.0+5.0+5.0	22995	50704	42.10
	C2-M+0.0BE+6.0+6.0+6.0+6.0	23620	52082	43.10
	C2-M+0.0BE+7.0+7.0+7.0+7.0	24247	53465	44.10
	C2-M+0.0BE+8.0+8.0+8.0+8.0	24599	54241	45.10
	C2-M+0.0BE+9.0+9.0+9.0+9.0	25297	55780	46.10
	C2-M+7.5BE+3.0+3.0+3.0+3.0	28955	63846	47.60
	C2-M+7.5BE+4.0+4.0+4.0+4.0	29059	64075	48.60
	C2-M+7.5BE+5.0+5.0+5.0+5.0	29516	65083	49.60
	C2-M+7.5BE+6.0+6.0+6.0+6.0	30153	66487	50.60
	C2-M+7.5BE+7.0+7.0+7.0+7.0	30752	67808	51.60
	C2-M+7.5BE+8.0+8.0+8.0+8.0	31120	68620	52.60
	C2-M+7.5BE+9.0+9.0+9.0+9.0	31802	70123	53.60

Tower Type	Tower Extension	Tower Weight kg	Tower Weight lbs	Structure Total Height m
C2-H	C2-H+0.0BE+3.0+3.0+3.0+3.0	23555	51939	40.70
	C2-H+0.0BE+4.0+4.0+4.0+4.0	23892	52682	41.70
	C2-H+0.0BE+5.0+5.0+5.0+5.0	24308	53599	42.70
	C2-H+0.0BE+6.0+6.0+6.0+6.0	24978	55076	43.70
	C2-H+0.0BE+7.0+7.0+7.0+7.0	25439	56093	44.70
	C2-H+0.0BE+8.0+8.0+8.0+8.0	26135	57628	45.70
	C2-H+0.0BE+9.0+9.0+9.0+9.0	26862	59231	46.70
	C2-H+7.5BE+3.0+3.0+3.0+3.0	30767	67841	48.20
	C2-H+7.5BE+4.0+4.0+4.0+4.0	31135	68653	49.20
	C2-H+7.5BE+5.0+5.0+5.0+5.0	31540	69546	50.20
	C2-H+7.5BE+6.0+6.0+6.0+6.0	32196	70992	51.20
	C2-H+7.5BE+7.0+7.0+7.0+7.0	32660	72015	52.20
	C2-H+7.5BE+8.0+8.0+8.0+8.0	33365	73570	53.20
	C2-H+7.5BE+9.0+9.0+9.0+9.0	34086	75160	54.20

NOTES:
1. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED

REV	REVISION REMARKS
3	ISSUED FOR IFCR
2	ISSUED FOR RFP
1	ISSUED FOR FINAL CLIENT REVIEW #1
0	ISSUED FOR REVIEW

hydro one

NOT FOR CONSTRUCTION

ASSET NAME: WAASIGAN
ASSET NO.

TITLE: 230kV DOUBLE CIRCUIT C2 TOWER FAMILY OUTLINE DRAWING

AR NO. | PID NO. | DATE YYYY/MM/DD: 2023/01/23 | SCALE: NTS

REF. ENGINEERING STANDARD | REF. MODEL/STANDARD DWG. NO. | REV. NO.

DRAWN BY: G. DECASTRO | DRAWING CHECKED BY:

DESIGNED BY: N. LEE | DESIGN APPROVED BY: A. RAO

DRAWING NO.: DP-03-06-0001 | SHEET NO.: 01 | REV NO.: 3

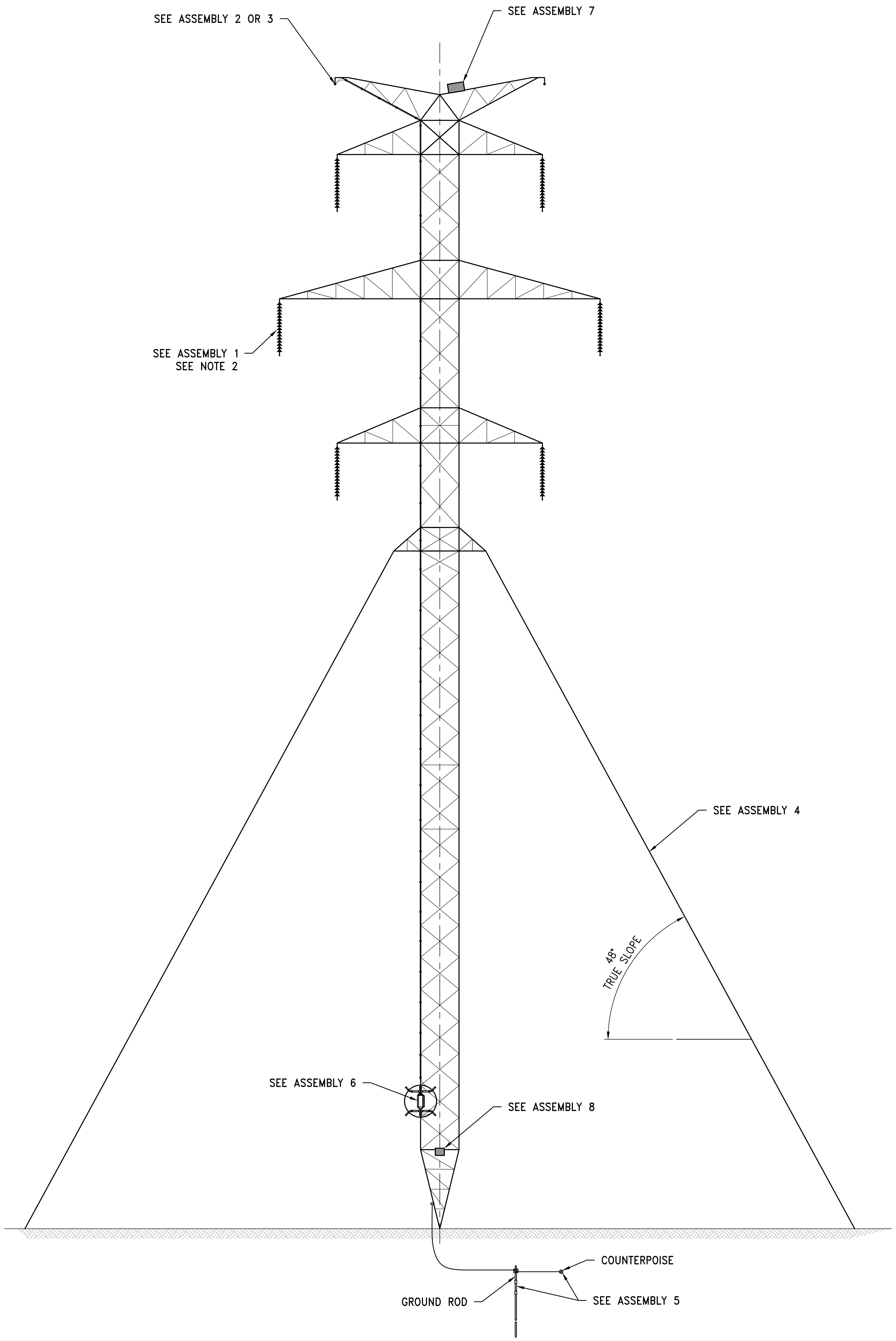
CONSULTANT: PHASOR ENGINEERING INC. | CONTRACT NO.

CLASS

TITLE BLOCK REV 10 - FEBRUARY 2020

A1 (594 x 841)

LIST OF ASSEMBLIES			
ASSEMBLY NO.	QUANTITY	DESCRIPTION	REFERENCE DRAWING
1	6	230KV SUSPENSION ASSEMBLY SINGLE STRING ASSEMBLY S1	DP-05-04-0001 OR 0003A
2	2	OPGW SUSPENSION ASSEMBLY DOUBLE CIRCUIT OPGW-DC-S	DP-05-04-0012
3	4	OPGW DEADEND ASSEMBLY WITH SPLICE DOUBLE CIRCUIT OPGW-DC-DE-SPLICE	DP-05-04-0016
4	4	DOUBLE CIRCUIT GUY ANCHOR ASSEMBLY (7/8")	DP-05-04-0021
5	1	GROUNDING DRAWING SUSPENSION STRUCTURES GROUNDING-S	DP-09-02-0002
6	1	OPGW SPLICE BOX OPGW-BOX	DP-05-04-0019
7	1	AERIAL NUMBER BOARD SIGNAGE-1	DP-07-02-0005
8	2	DANGER SIGN SIGNAGE-2	DP-07-02-0006



NOTES:
1. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED.
2. USE DOUBLE STRING ASSEMBLY FOR CRITICAL CROSSING TOWERS.

REV	REVISION REMARKS
3	ISSUED FOR IFCR
2	ISSUED FOR RFP
1	ISSUED FOR FINAL CLIENT REVIEW #1
0	ISSUED FOR REVIEW

hydro one

NOT FOR CONSTRUCTION

ASSET NAME: WAASIGAN
ASSET NO.:

TITLE: 230kV DOUBLE CIRCUIT GUYED TANGENT C2-GT STEEL LATTICE TOWER OUTLINE DRAWING

AR NO.: | PID NO.: | DATE YYYY/MM/DD: 2023/01/23 | SCALE: NTS

REF. ENGINEERING STANDARD: | REF. MODEL/STANDARD DWG. NO.: | REV. NO.:

DRAWN BY: G. DECASTRO | DRAWING CHECKED BY:

DESIGNED BY: N. LEE | DESIGN APPROVED BY: A. RAO

DRAWING NO.: DP-03-06-0002 | SHEET NO.: 01 | REV NO.: 3

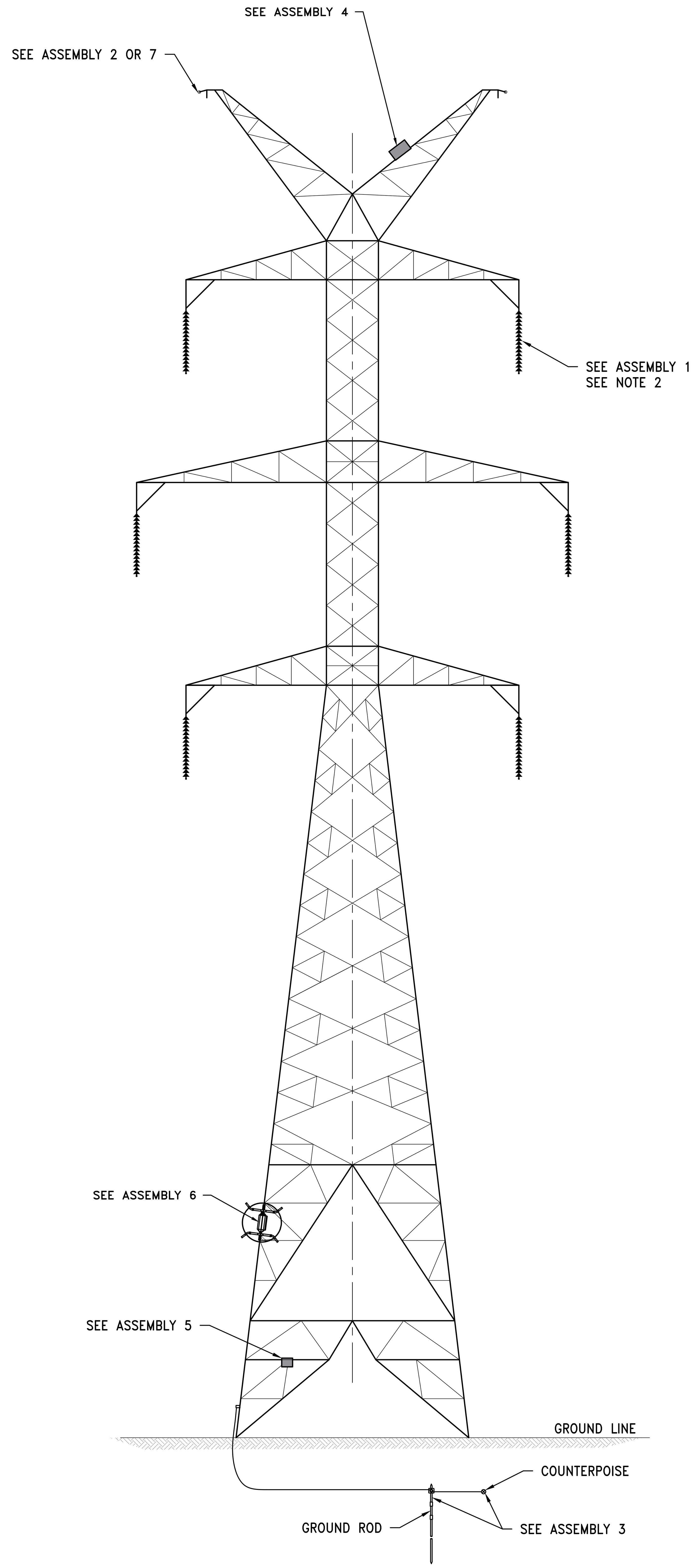
CONSULTANT: PHASOR ENGINEERING INC. A QUANTA SERVICES COMPANY | CONTRACT NO.:

CLASS

A1 (594 x 841)

millimetres 0 10 50 100 200 250 300

LIST OF ASSEMBLIES			
ASSEMBLY NO.	QUANTITY	DESCRIPTION	REFERENCE DRAWING
1	6	230KV LIGHT ANGLE ASSEMBLY SINGLE STRING L1	DP-05-04-0002 OR 0003B
2	2	OPGW SUSPENSION ASSEMBLY DOUBLE CIRCUIT OPGW-DC-S	DP-05-04-0012
3	1	GROUNDING DRAWING SUSPENSION STRUCTURES GROUNDING-S	DP-09-02-0002
4	1	AERIAL NUMBER BOARD SIGNAGE-1	DP-07-02-0005
5	2	DANGER SIGN SIGNAGE-2	DP-07-02-0006
6	1	OPGW SPLICE BOX OPGW-BOX	DP-05-04-0019
7	4	OPGW DEADEND ASSEMBLY WITH SPLICE DOUBLE CIRCUIT OPGW-DC-DE-SPLICE	DP-05-04-0016



NOTES:
1. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED.
2. USE DOUBLE STRING ASSEMBLY FOR CRITICAL CROSSING TOWERS.

REV	REVISION REMARKS
3	ISSUED FOR IFCR
2	ISSUED FOR RFP
1	ISSUED FOR FINAL CLIENT REVIEW #1
0	ISSUED FOR REVIEW

NOT FOR CONSTRUCTION

ASSET NAME: WAASIGAN
ASSET NO.:

TITLE: 230kV DOUBLE CIRCUIT SUSPENSION LIGHT ANGLE (0-15°) C2-L STEEL LATTICE TOWER OUTLINE DRAWING

AR NO.	PID NO.	DATE YYYY/MM/DD	SCALE
		2023/01/23	NTS

REF. ENGINEERING STANDARD:
REF. MODEL/STANDARD DWG. NO.:
REV. NO.:

DRAWN BY: G. DECASTRO
DRAWING CHECKED BY:
DESIGNED BY: C. HENDERSON
DESIGN APPROVED BY: A. RAO

DRAWING NO.: DP-03-06-0003
SHEET NO.: 01
REV NO.: 3

CONSULTANT: PHASOR ENGINEERING INC
CONTRACT NO.:

CLASS

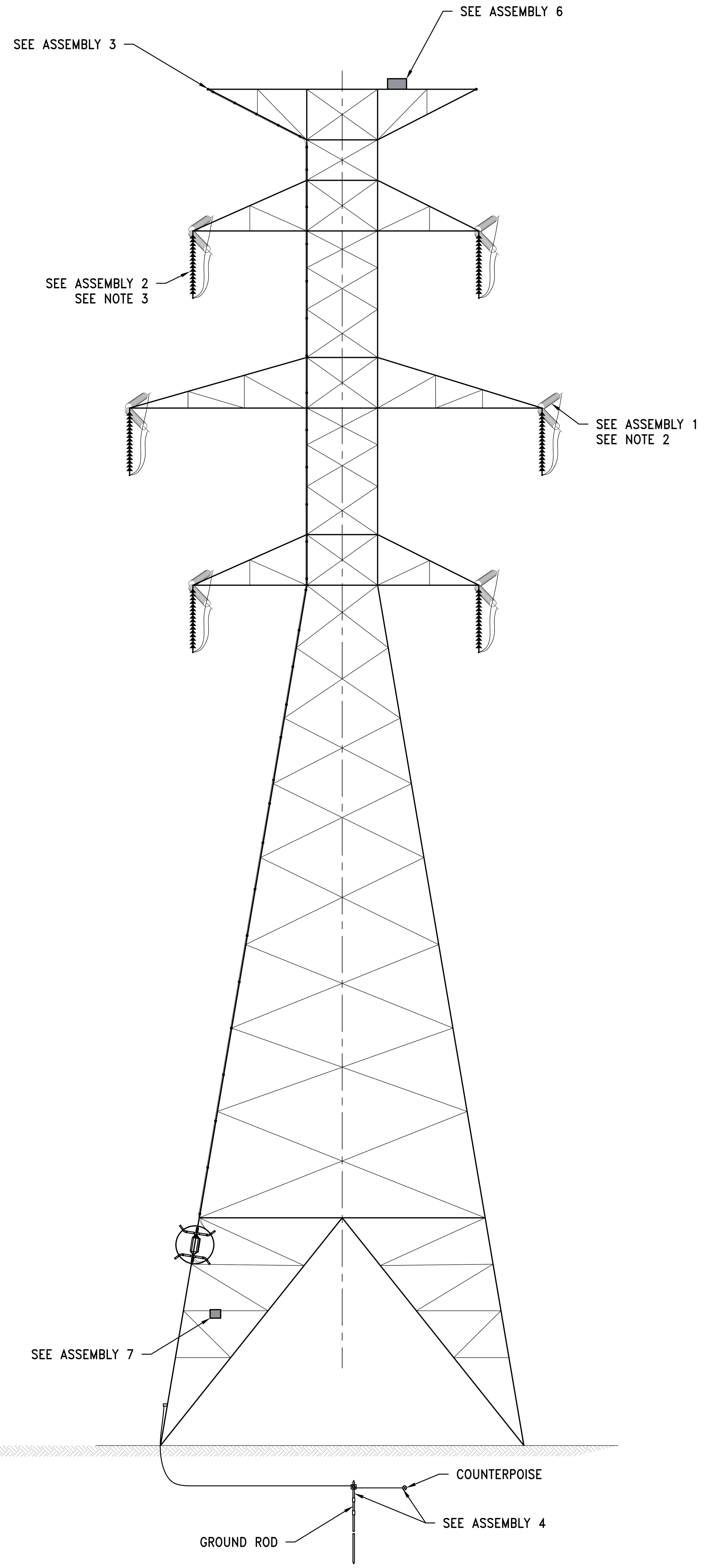
A1 (594 x 841)

millimetres 0 10 50 100 200 250 300

TITLE BLOCK REV 10 - FEBRUARY 2020

LIST OF ASSEMBLIES			
ASSEMBLY NO.	QUANTITY	DESCRIPTION	REFERENCE DRAWING
1	12	230KV DEADEND ASSEMBLY SINGLE STRING D1	DP-05-04-0004 OR DP-05-04-0006
*2	VARIES	230KV SUSPENSION ASSEMBLY SINGLE STRING S1	DP-05-04-0001
3	4	OPGW DEADEND ASSEMBLY WITH SPLICE DOUBLE CIRCUIT OPGW-DC-DE-SPLICE	DP-05-04-0016
4	1	GROUNDING DRAWING DEADEND STRUCTURES GROUNDING DE	DP-09-02-0001
5	1	OPGW SPLICE BOX OPGW-BOX	DP-05-04-0019
6	1	AERIAL NUMBER BOARD SIGNAGE-1	DP-07-02-0005
7	2	DANGER SIGN SIGNAGE-2	DP-07-02-0006

* SEE NOTE 3



NOTES:
1. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED.
2. USE DOUBLE STRING ASSEMBLY FOR CRITICAL CROSSING TOWERS, ASSEMBLY DP-05-04-0006.
3. CONFIGURATION OF ASSEMBLY 2 WILL BE DEPENDENT ON CHART BELOW.

ANGLE (DEG)	ASSEMBLY COUNT
<30	6
>30-<45	9

REV	REVISION REMARKS
3	ISSUED FOR IFCR
2	ISSUED FOR RFP
1	ISSUED FOR FINAL CLIENT REVIEW #1
0	ISSUED FOR REVIEW

hydro one

NOT FOR CONSTRUCTION

ASSET NAME: WAASIGAN
ASSET NO.:

TITLE: 230kV DOUBLE CIRCUIT MEDIUM ANGLE C2-M (0°-45°) STEEL LATTICE TOWER OUTLINE DRAWING

AR NO.: | PID NO.: | DATE YYYY/MM/DD: 2023/01/23 | SCALE: NTS

REF. ENGINEERING STANDARD: | REF. MODEL/STANDARD DWG. NO.: | REV. NO.:

DRAWN BY: G. DECASTRO | DRAWING CHECKED BY:

DESIGNED BY: S. KHAN | DESIGN APPROVED BY: A. RAO

DRAWING NO.: DP-03-06-0004 | SHEET NO.: 01 | REV. NO.: 3

CONSULTANT: PHASOR ENGINEERING INC. A QUANTA SERVICES COMPANY | CONTRACT NO.:

CLASS

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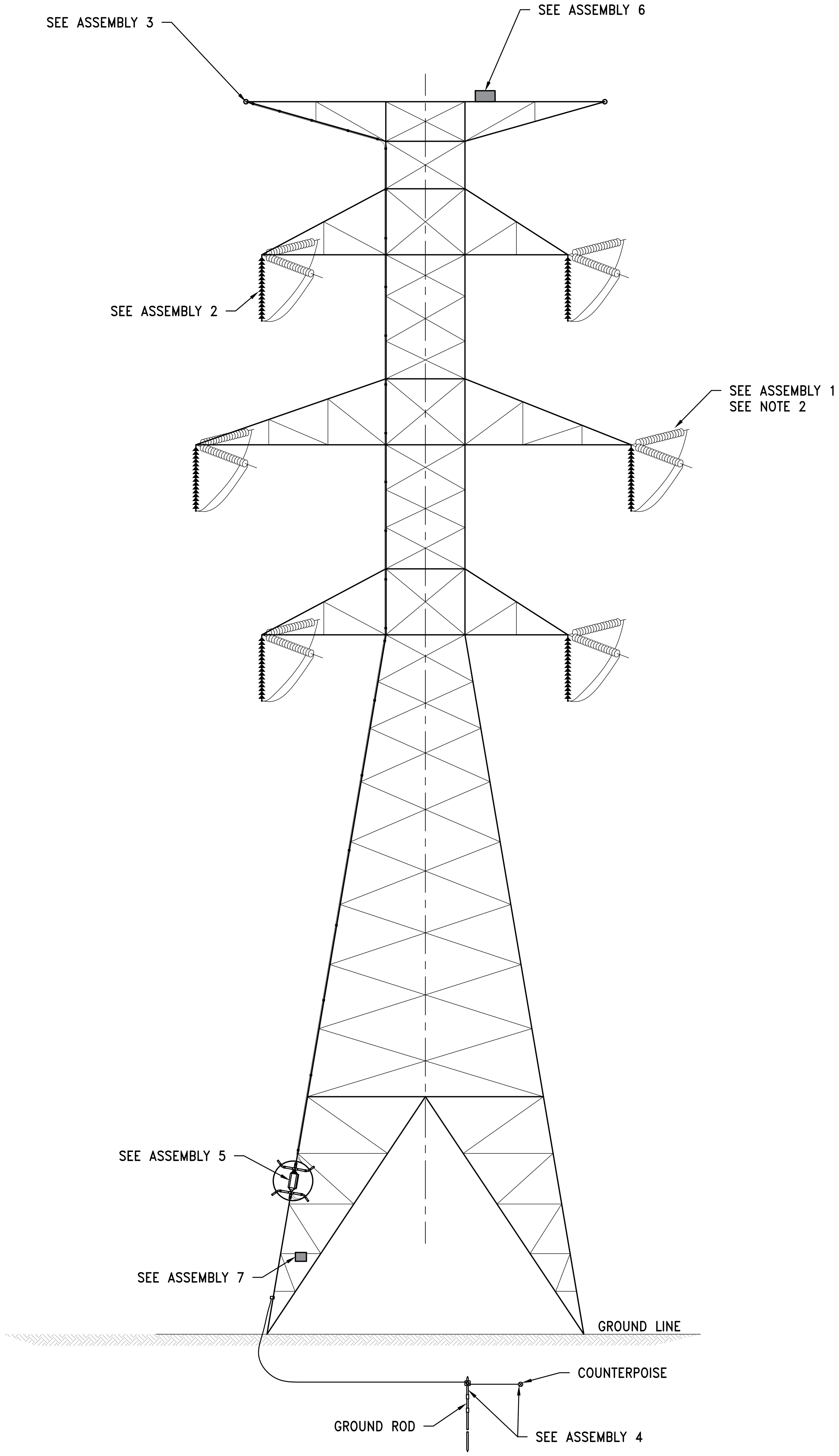
millimetres 0 10 50 100 200 250 300

TITLE BLOCK REV 10 - FEBRUARY 2020

LIST OF ASSEMBLIES			
ASSEMBLY NO.	QUANTITY	DESCRIPTION	REFERENCE DRAWING
1	12	230KV DEADEND ASSEMBLY SINGLE STRING D1	DP-05-04-0004 OR DP-05-04-0006
2	9	230KV SUSPENSION ASSEMBLY SINGLE STRING S1	DP-05-04-0001
3	4	OPGW DEADEND ASSEMBLY WITH SPLICE DOUBLE CIRCUIT OPGW-DC-DE-SPLICE	DP-05-04-0016
4	1	GROUNDING DRAWING DEADEND STRUCTURES GROUNDING DE	DP-09-02-0001
5	1	OPGW SPLICE BOX OPGW-BOX	DP-05-04-0019
6	1	AERIAL NUMBER BOARD SIGNAGE-1	DP-07-02-0005
7	2	DANGER SIGN SIGNAGE-2	DP-07-02-0006



NOTES:
1. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED.
2. USE DOUBLE STRING ASSEMBLY FOR CRITICAL CROSSING TOWERS, ASSEMBLY DP-05-04-0006.

REV	REVISION REMARKS
3	ISSUED FOR IFCR
2	ISSUED FOR RFP
1	ISSUED FOR FINAL CLIENT REVIEW #1
0	ISSUED FOR REVIEW

hydro one

NOT FOR CONSTRUCTION

ASSET NAME: WAASIGAN
ASSET NO.:

TITLE: 230kV DOUBLE CIRCUIT HEAVY ANGLE C2-H (45°-60°) STEEL LATTICE TOWER OUTLINE DRAWING

AR NO.	PID NO.	DATE YYYY/MM/DD	SCALE
		2023/01/23	NTS

REF. ENGINEERING STANDARD:
REF. MODEL/STANDARD DWG. NO.:
REV. NO.:

DRAWN BY: G. DECASTRO
DRAWING CHECKED BY:
DESIGNED BY: C. HENDERSON
DESIGN APPROVED BY: A. RAO

DRAWING NO.: DP-03-06-0005
SHEET NO.: 01
REV NO.: 3

CONSULTANT: PHASOR ENGINEERING INC. A QUANTA SERVICES COMPANY
CONTRACT NO.:

CLASS

A1 (594 x 841)

millimetres 0 10 50 100 200 250 300

TITLE BLOCK REV 10 - FEBRUARY 2020

MAP LAYOUTS OF
PROJECT IMPACTED TRANSFORMER STATIONS

MAP LAYOUTS OF PROJECT IMPACTED TRANSFORMER STATIONS

The below three station site maps illustrate the anticipated impacts of the Waasigan Project on each station's footprint.

Project Scope and design will necessitate the footprint expansion at certain Hydro One stations, as shown on the three station map layouts below. Hydro One currently owns all the property required for these expansions.

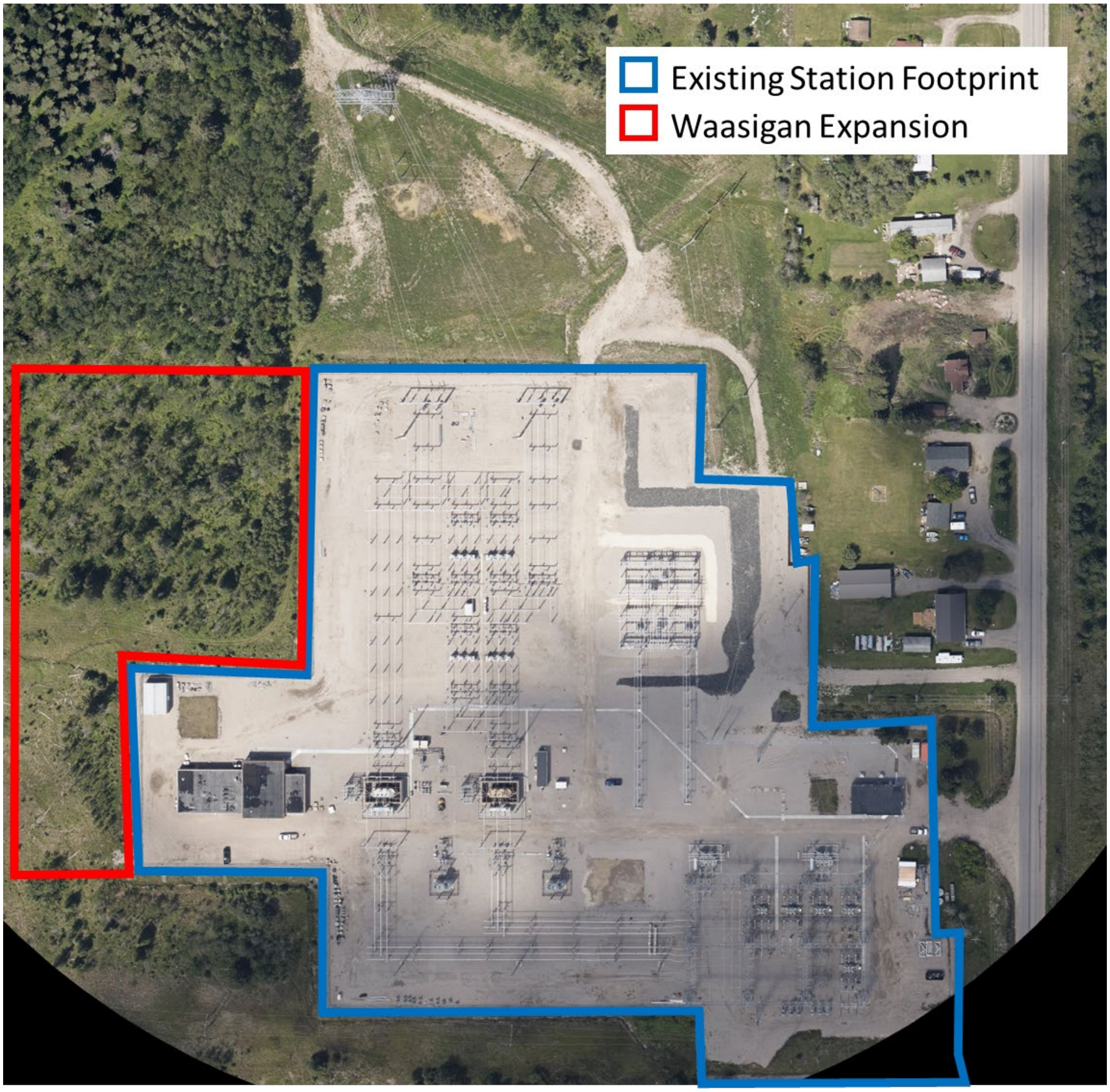
Please refer to **Exhibit E, Tab 1, Schedule 1**, for further details regarding land rights.

MAP OF LAKEHEAD TS

Illustration of Existing Station Footprint and the Expansion required for the Project.

MAP OF DRYDEN TS

Illustration of Existing Station Footprint and the Expansion required for the Project.



MAP OF MACKENZIE TS

Illustration of Existing Station Footprint and the Expansion required for the Project.

MAPS

The Project consists of two phases. Phase 1 will span approximately 190km of 230 kV double-circuit transmission line from Lakehead TS to the Mackenzie TS, and Phase 2 will span approximately 170km of 230 kV single-circuit transmission line from Mackenzie TS to Dryden TS.

A map indicating the geographic location of the Project is included as **Attachment 1** to this Schedule. Hydro One is providing this map with the expectation that it will be used by the OEB as the *Notice Map* in this proceeding.

A more detailed map showing the location and route of the Project is included as **Attachment 2** of this schedule.

A map including the property lot numbers and/or concessions is provided at **Attachment 3** of this schedule. Where lot numbers or concessions are not indicated, this is attributable to the township not having been divided into lots and/or concessions.

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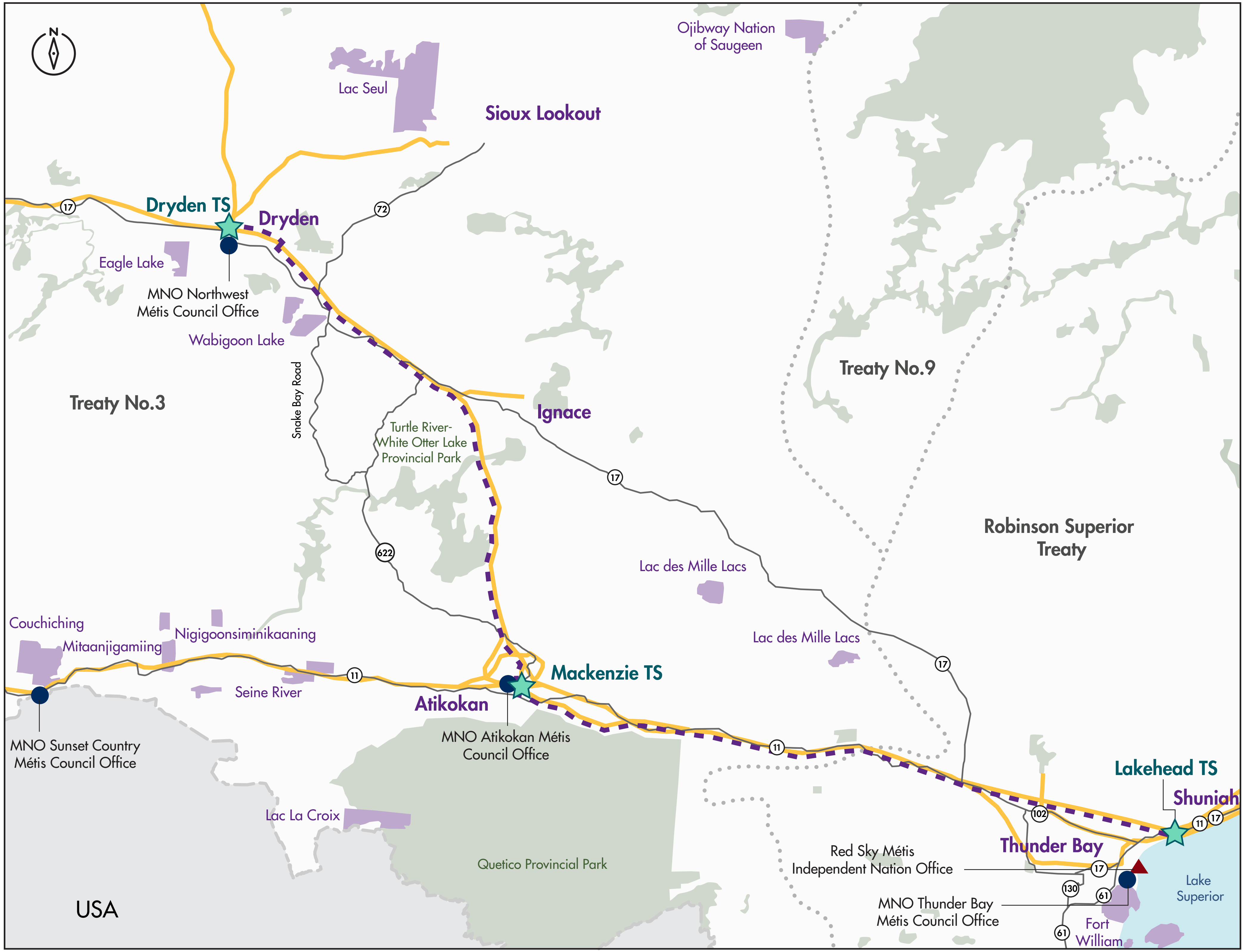
NOTICE MAP

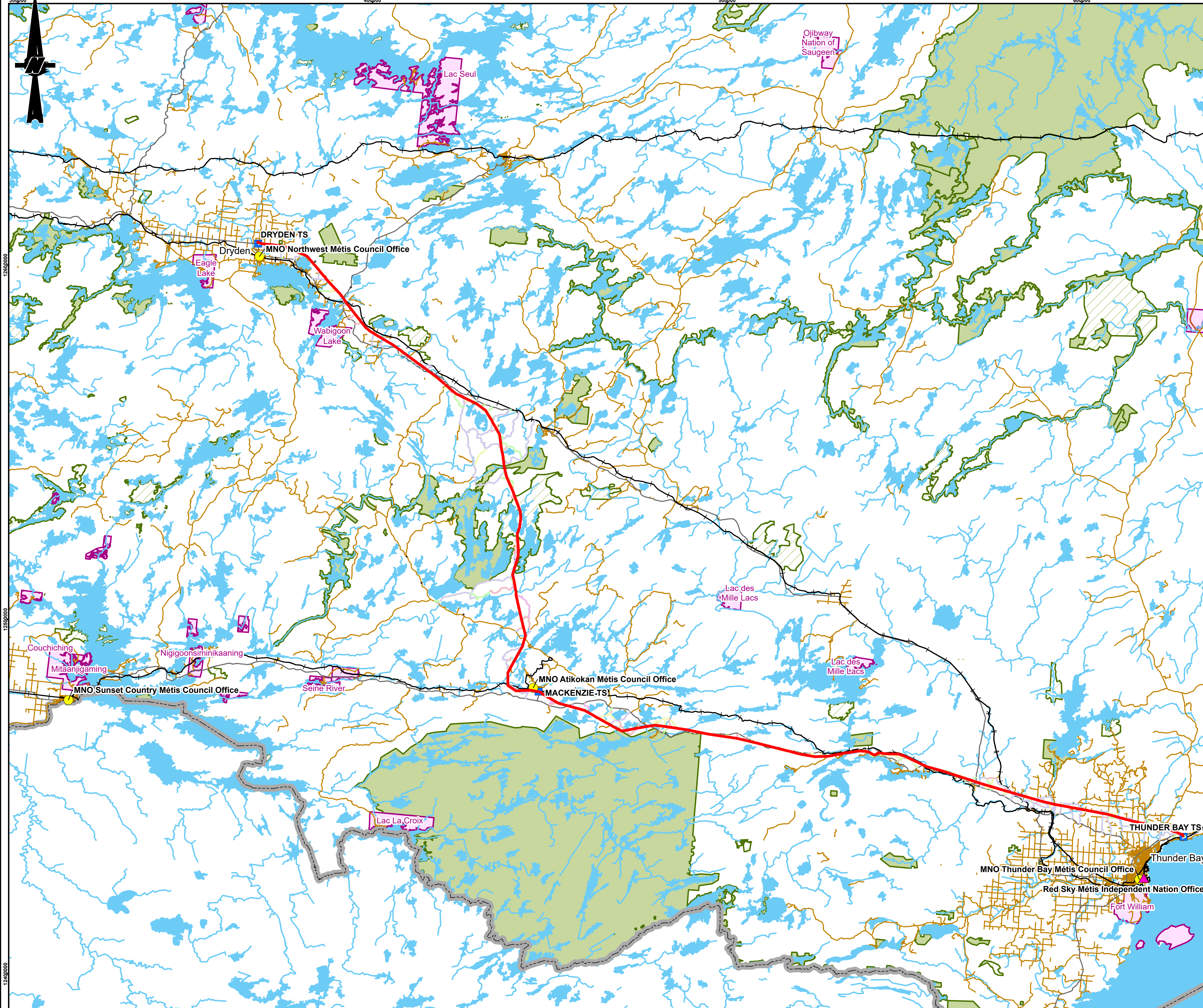
WAASIGAN TRANSMISSION LINE

Map Legend

- Existing Transformer Station (TS)
- Preferred Route
- Existing Transmission Line
- Highway
- International Border
- Red Sky Métis Independent Nation Office
- Métis Nation of Ontario (MNO) Council Office
- Treaty Boundary
- First Nation Reserve
- Provincial Park



DETAILED ROUTE MAP



LEGEND

- 230 kV TRANSFORMER STATION (TS)
- RED SKY MÉTIS INDEPENDENT NATION OFFICE
- MNO COUNCIL OFFICE
- PRELIMINARY PREFERRED ROUTE ALIGNMENT
- INTERNATIONAL BORDER
- LOCAL ROAD
- SECONDARY HIGHWAY
- RAILWAY
- WATERCOURSE
- WATERBODY
- WATERCOURSE
- LOCAL STUDY AREA
- LOCAL STUDY AREA
- LOCAL STUDY AREA
- CONSERVATION RESERVE
- FIRST NATIONS RESERVE
- PROVINCIAL PARK
- WATERBODY

0 25 50
1:1,100,000 KILOMETRES

REFERENCE(S)
BASE DATA COURTESY OF LAND INFORMATION ONTARIO MNRF.
PROJECTION: HYDRO ONE LAMBERT CONFORMAL CONIC DATUM: NAD 83

CLIENT
HYDRO ONE NETWORKS INC.

hydro one

PROJECT
WAASIGAN TRANSMISSION LINE

TITLE
PROJECT LOCATION AND PRELIMINARY PREFERRED ALIGNMENT

CONSULTANT
wsp GOLDER

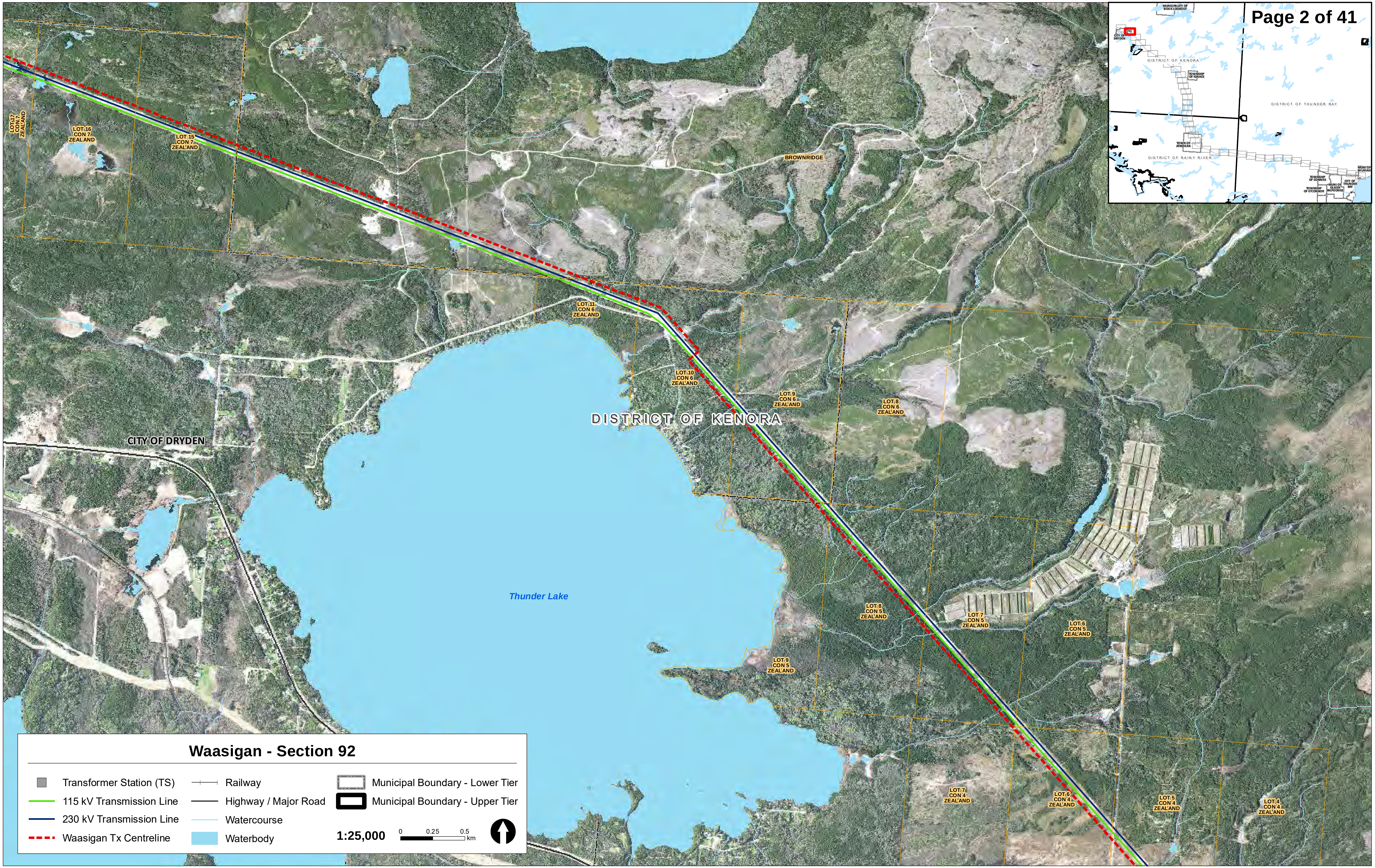
YYYY-MM-DD	2022-10-06
DESIGNED	CS
PREPARED	MM
REVIEWED	####
APPROVED	####

PROJECT NO.	CONTROL	REV.	FIGURE
20137728	0020	A	1

IF THIS MEASUREMENT DOES NOT MATCH WHAT IS SHOWN, THE SHEET SIZE HAS BEEN MODIFIED FROM: ANSI B

INDIVIDUAL PROPERTY MAPS

Produced By: Hydro One Networks Inc., GIS Services
Date: May 26, 2023
Map23-038_Waasigan_Section92_Tile



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Date: May 26, 2023
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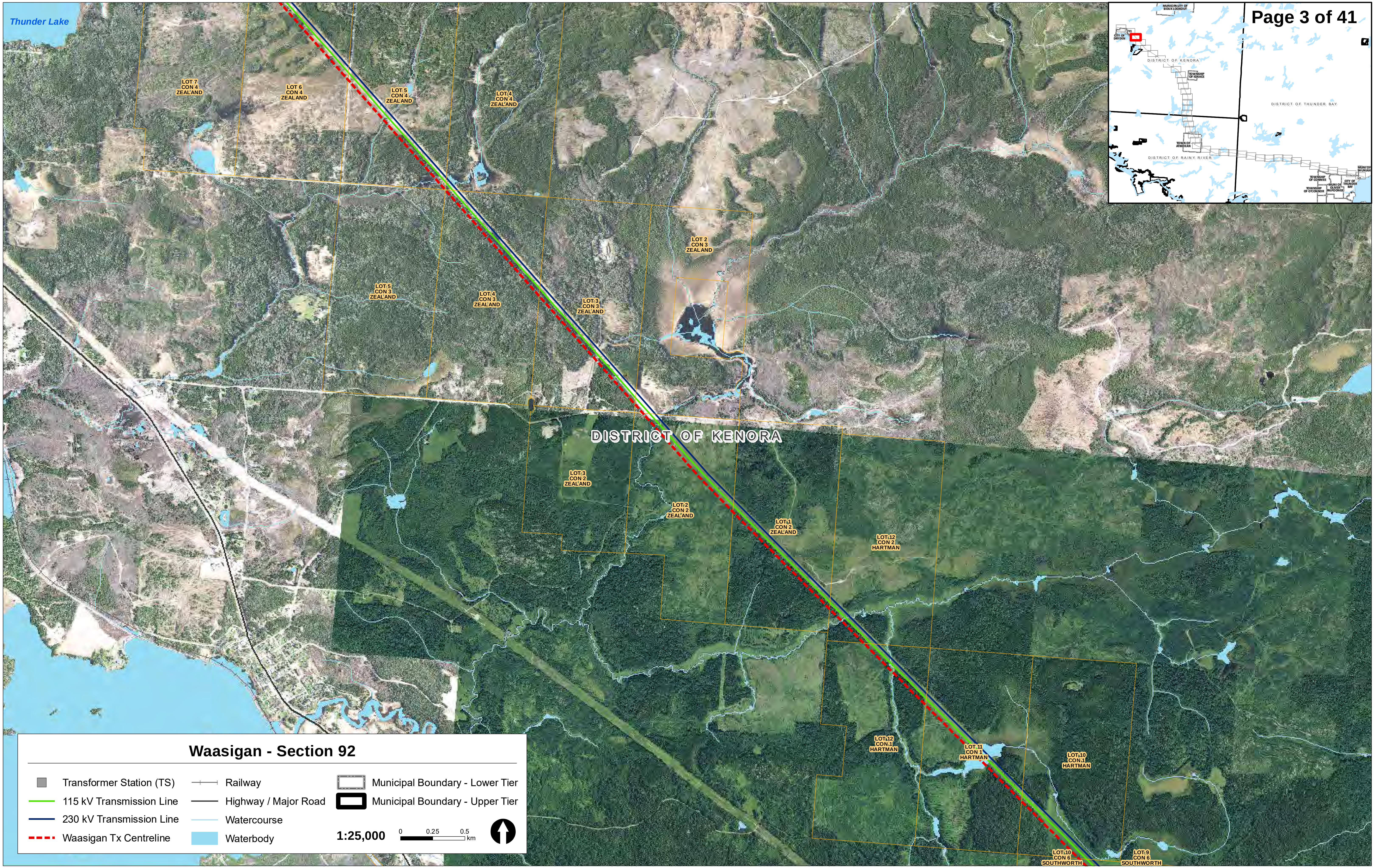

hydro one

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Date: May 26, 2023
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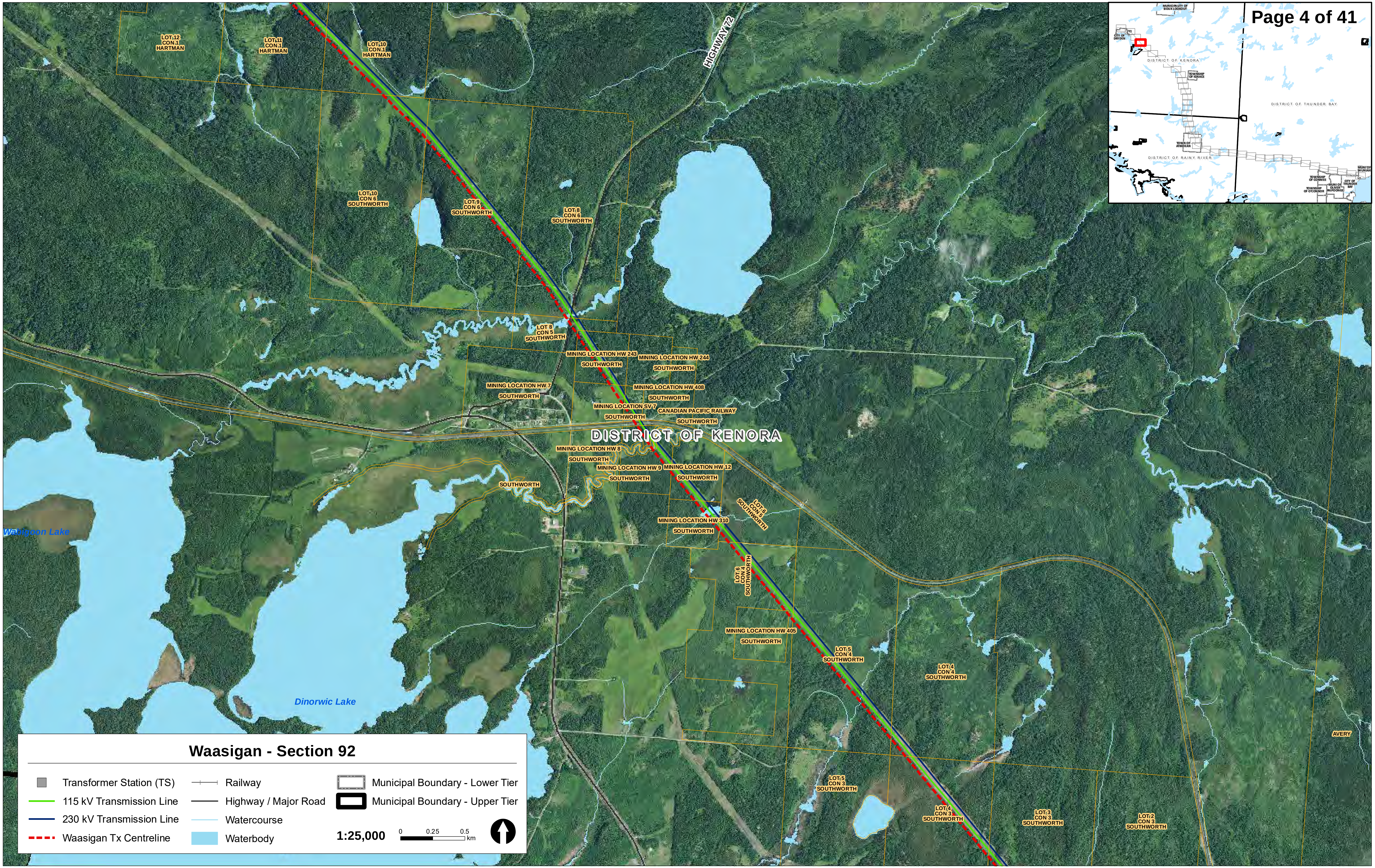

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Date: May 26, 2023
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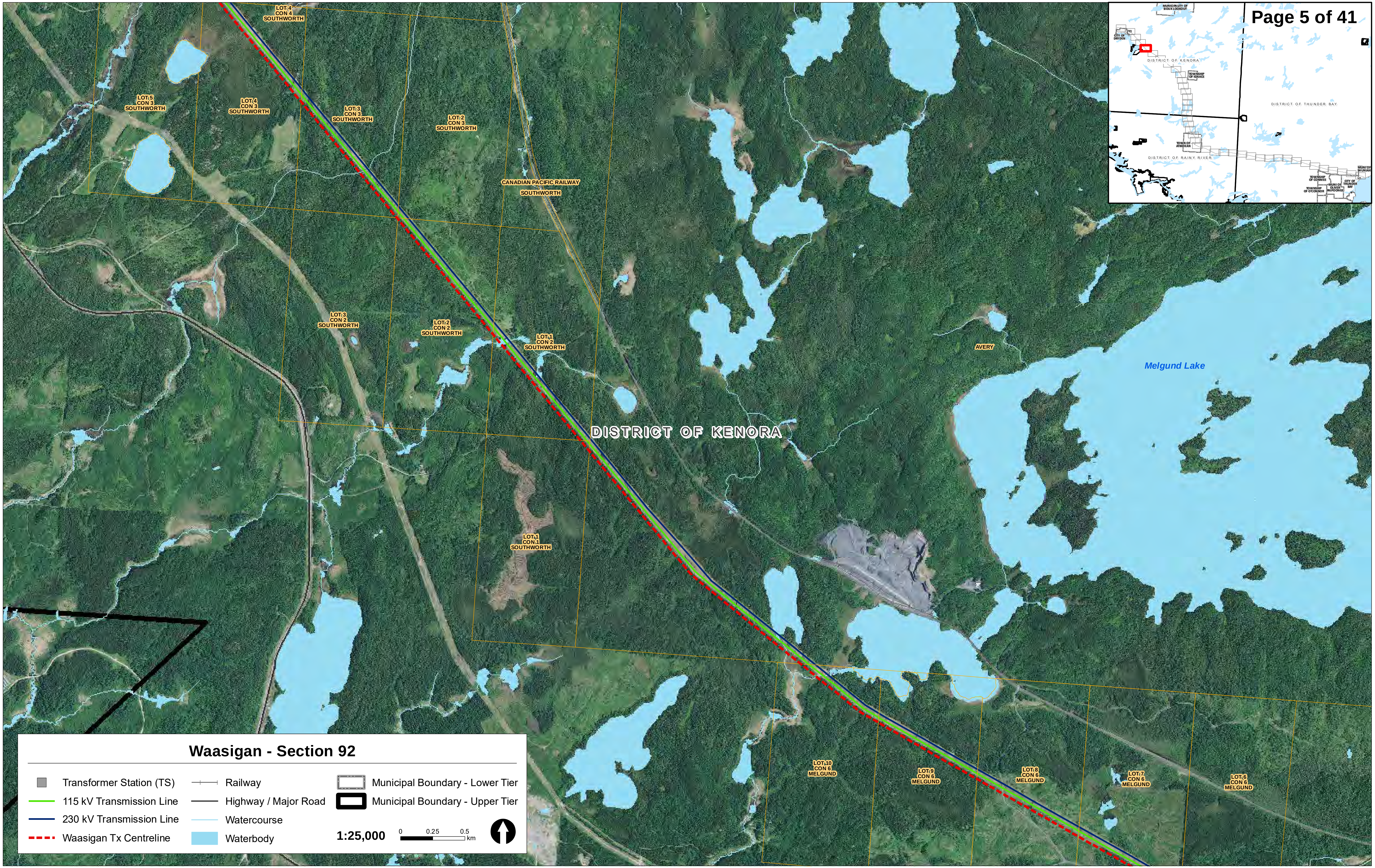

Waasigan - Section 92

Transformer Station (TS)	Railway	Municipal Boundary - Lower Tier
115 kV Transmission Line	Highway / Major Road	Municipal Boundary - Upper Tier
230 kV Transmission Line	Watercourse	
Waasigan Tx Centreline	Waterbody	

1:25,000 — 0 0.25 0.5 km

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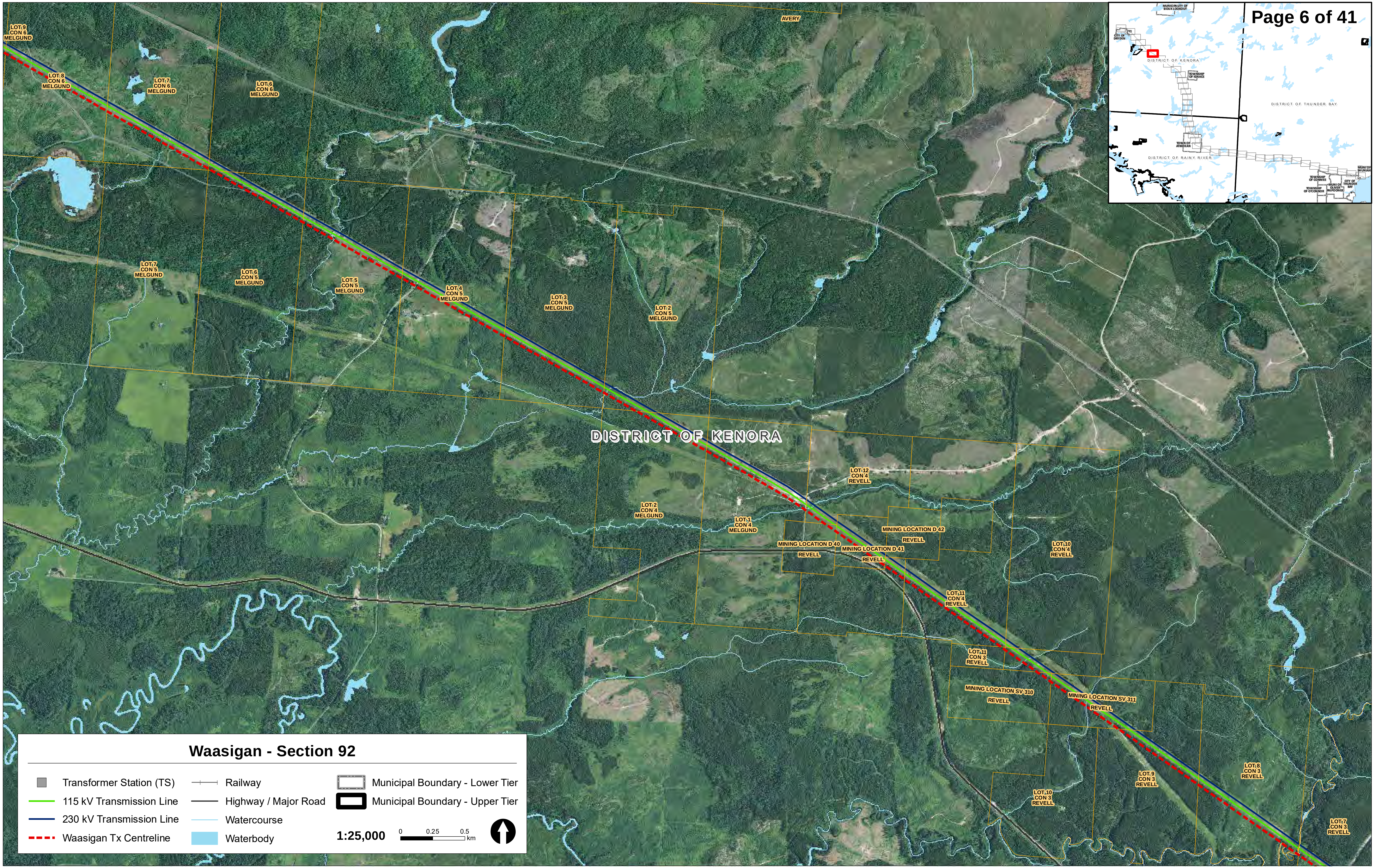
Date: May 26, 2023
Map23-038_Waasigan_Section92_Tile



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Date: May 26, 2023
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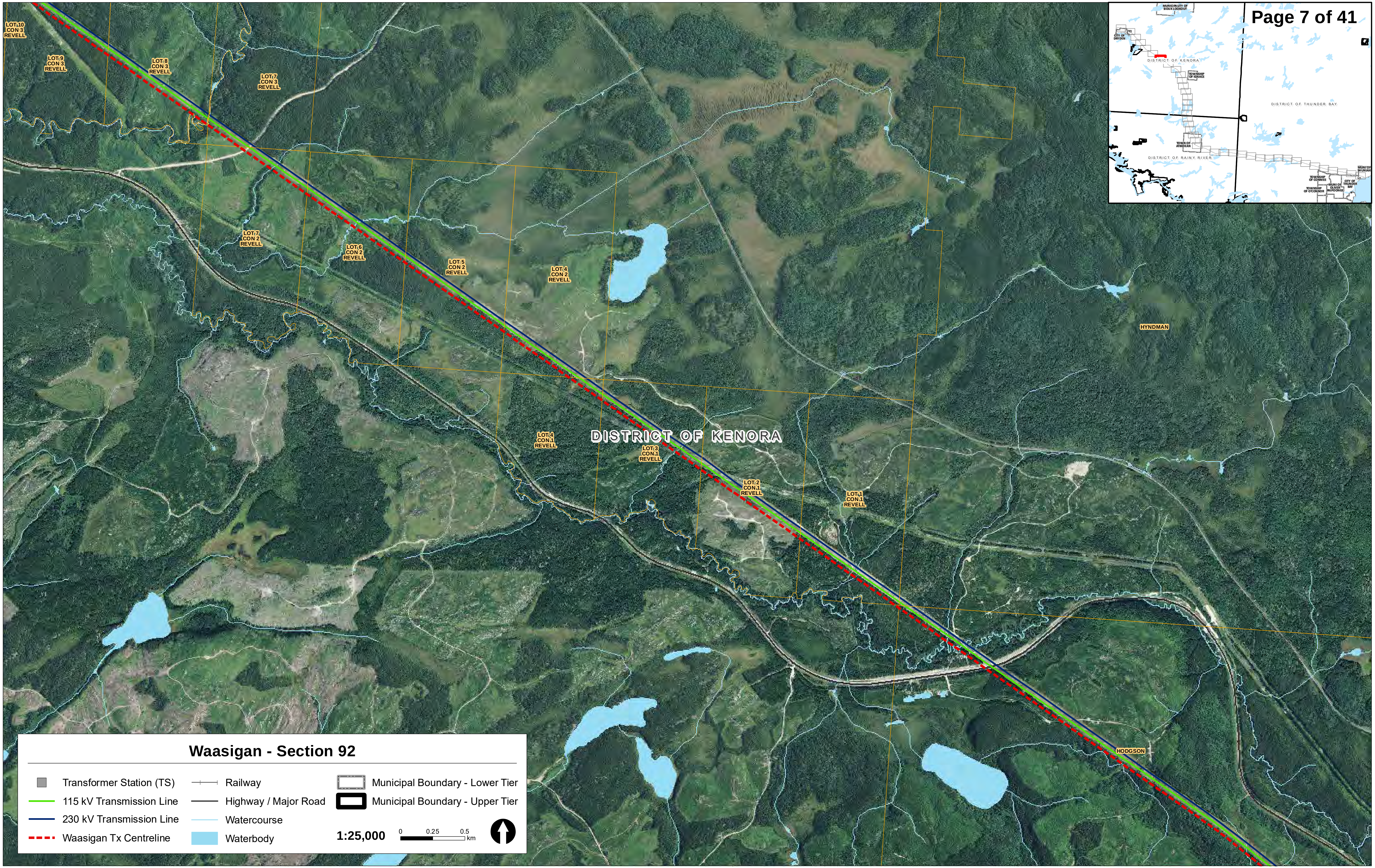

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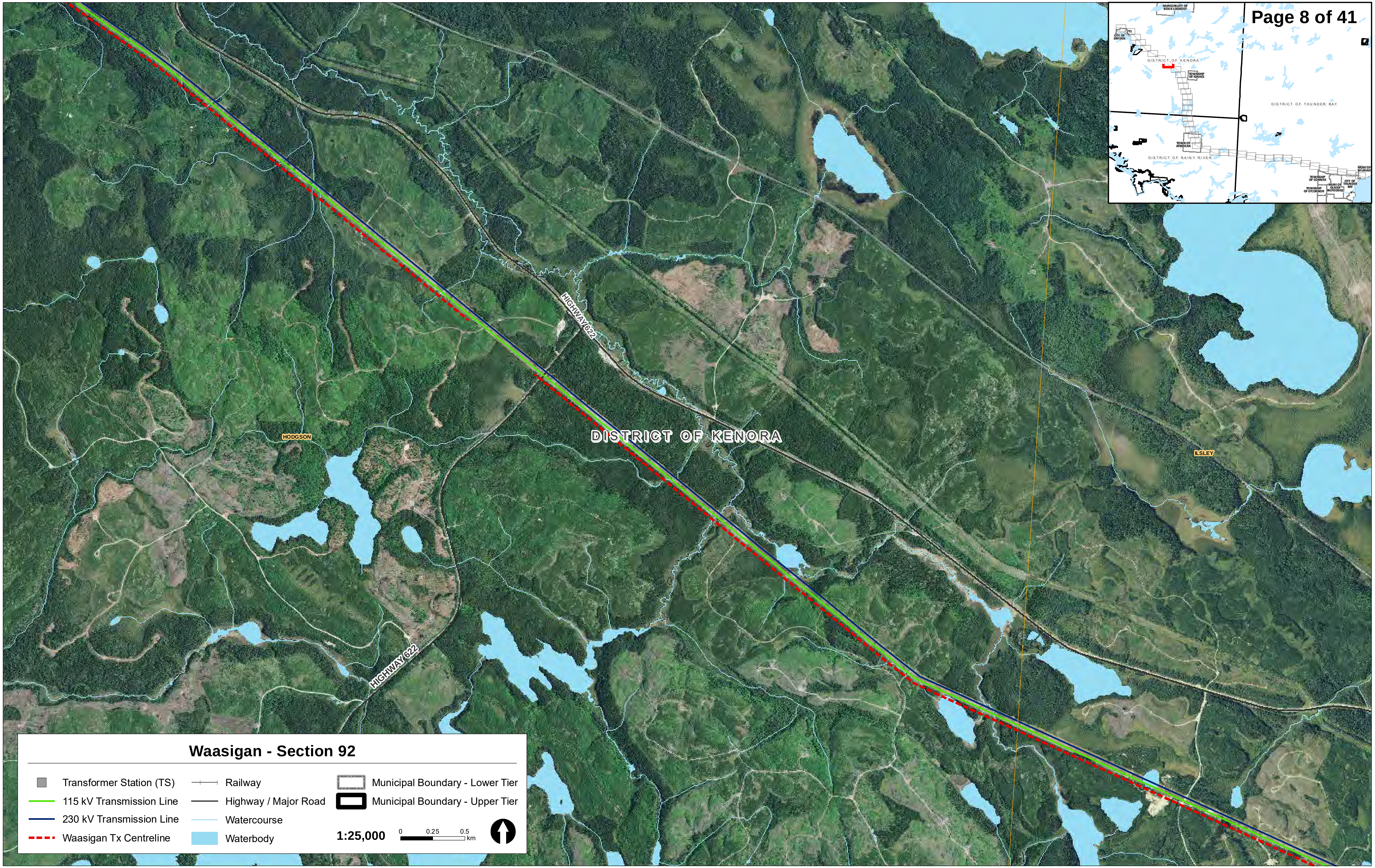

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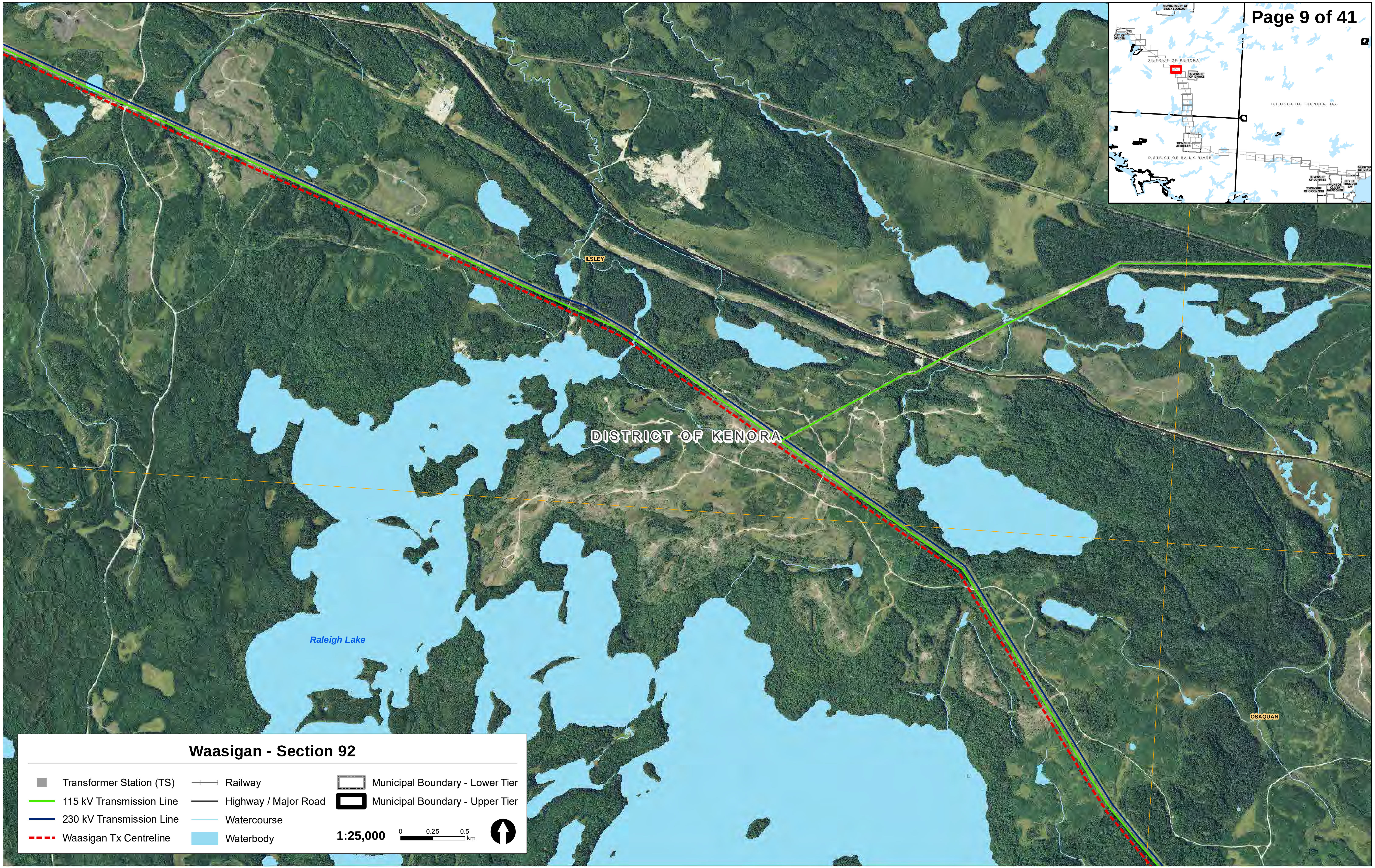

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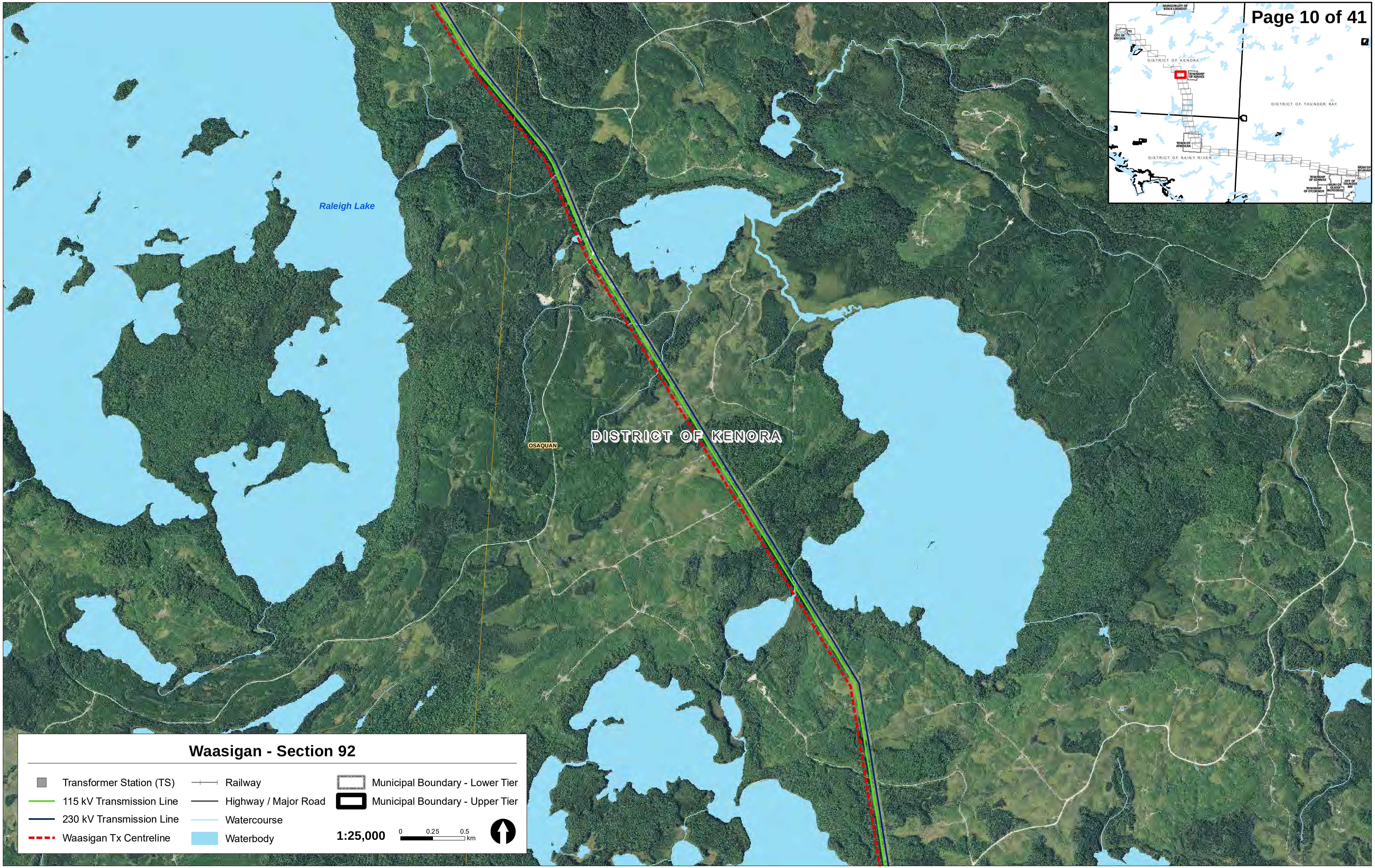

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Date: May 26, 2023
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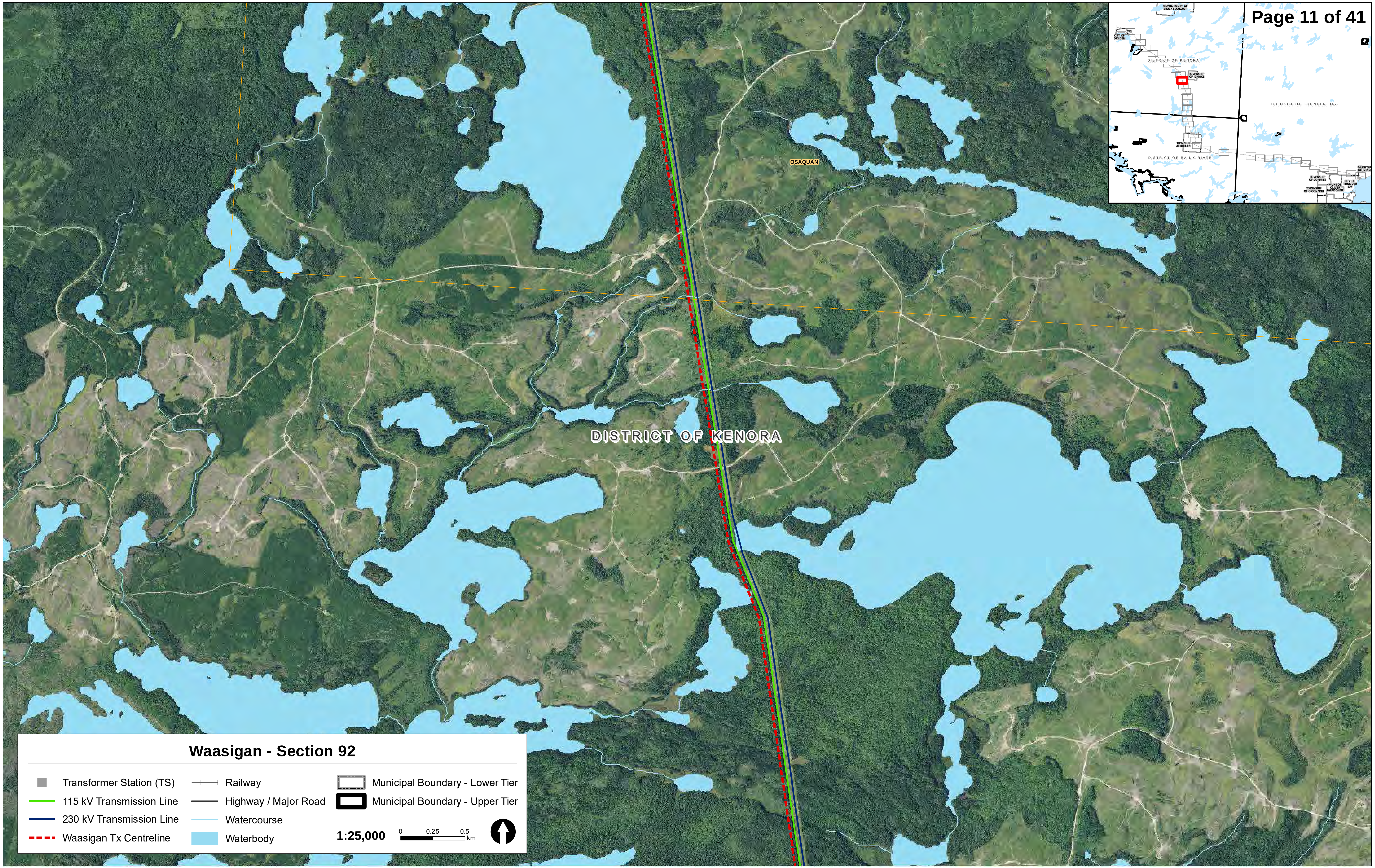

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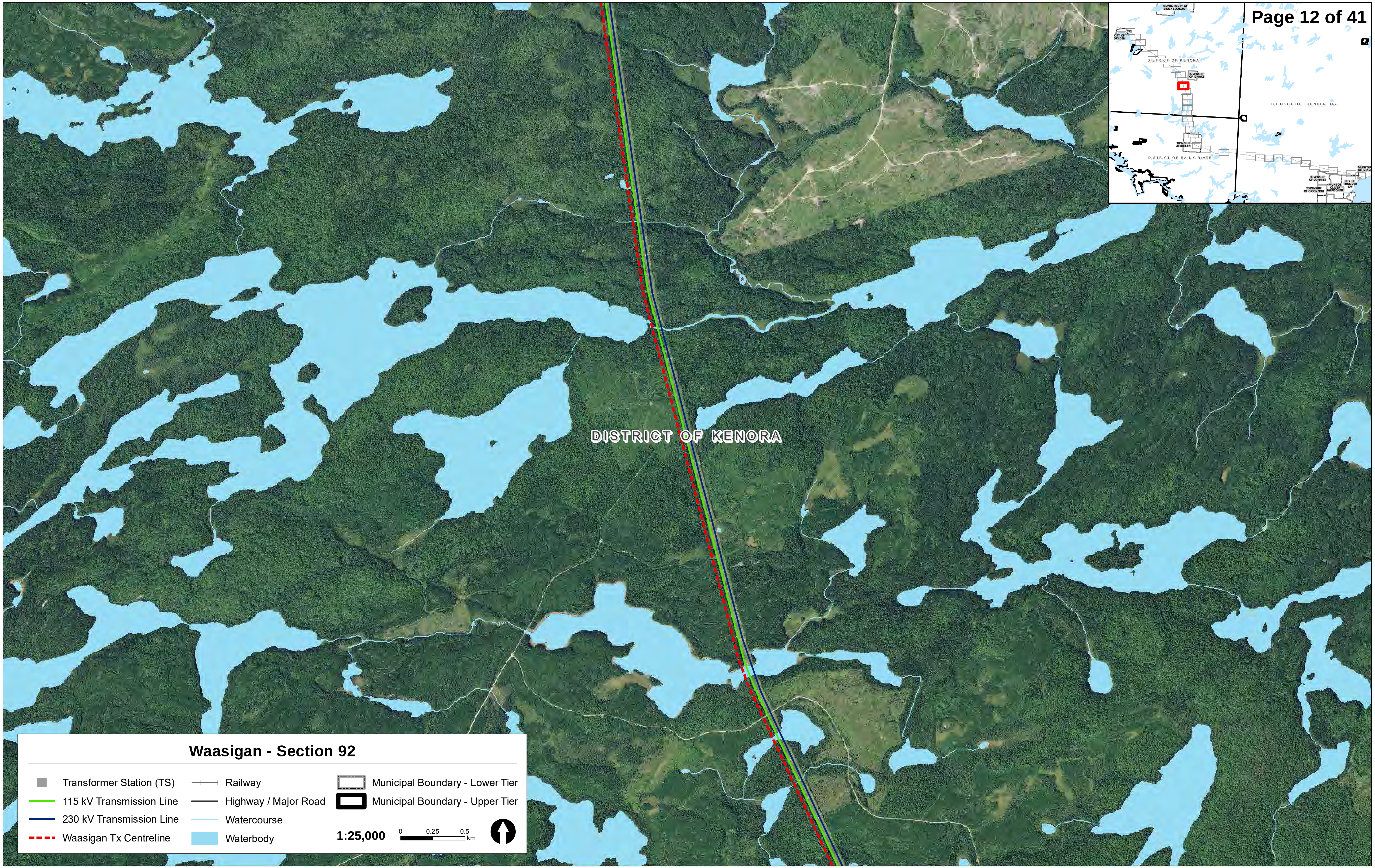

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Date: May 26, 2023
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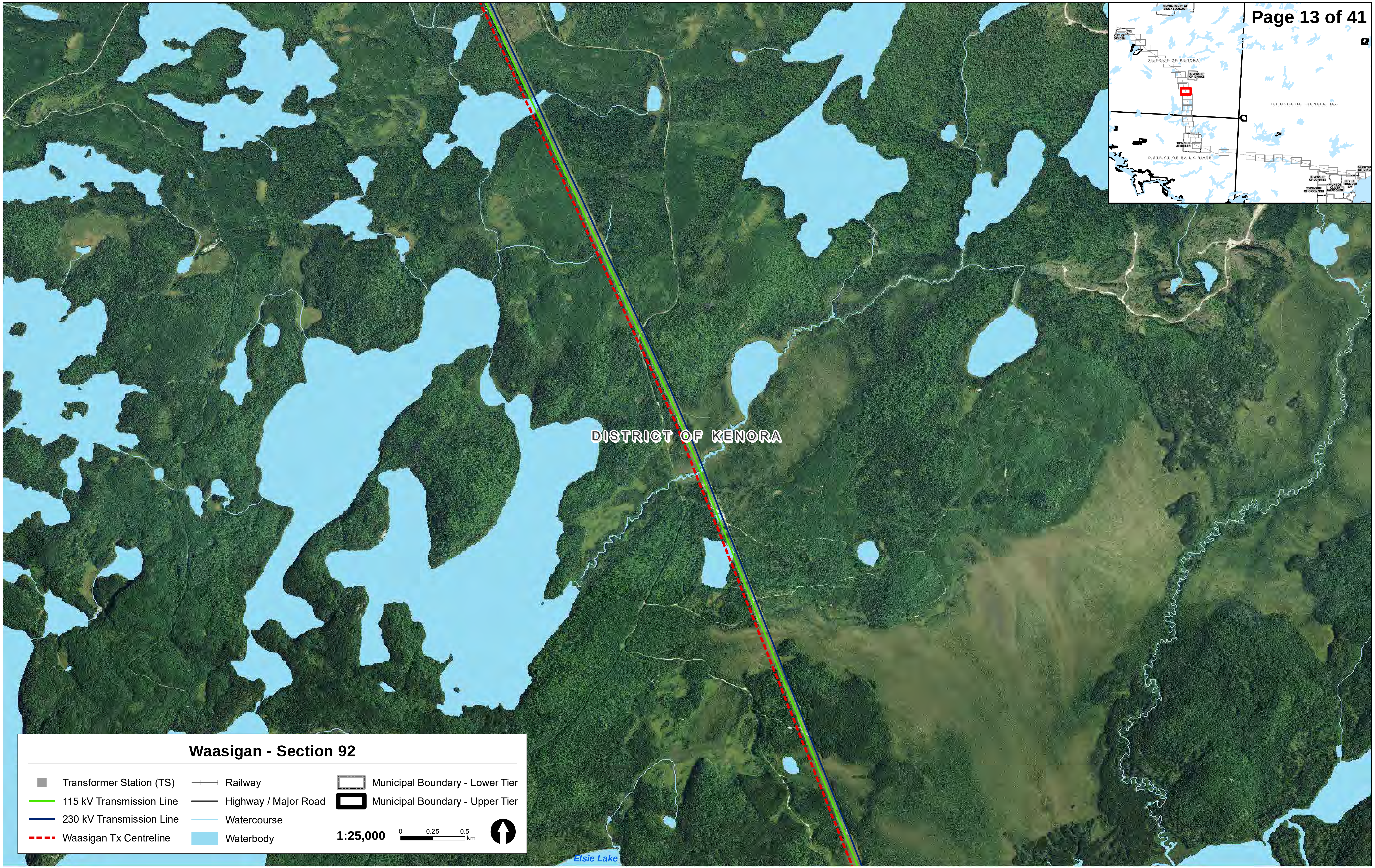

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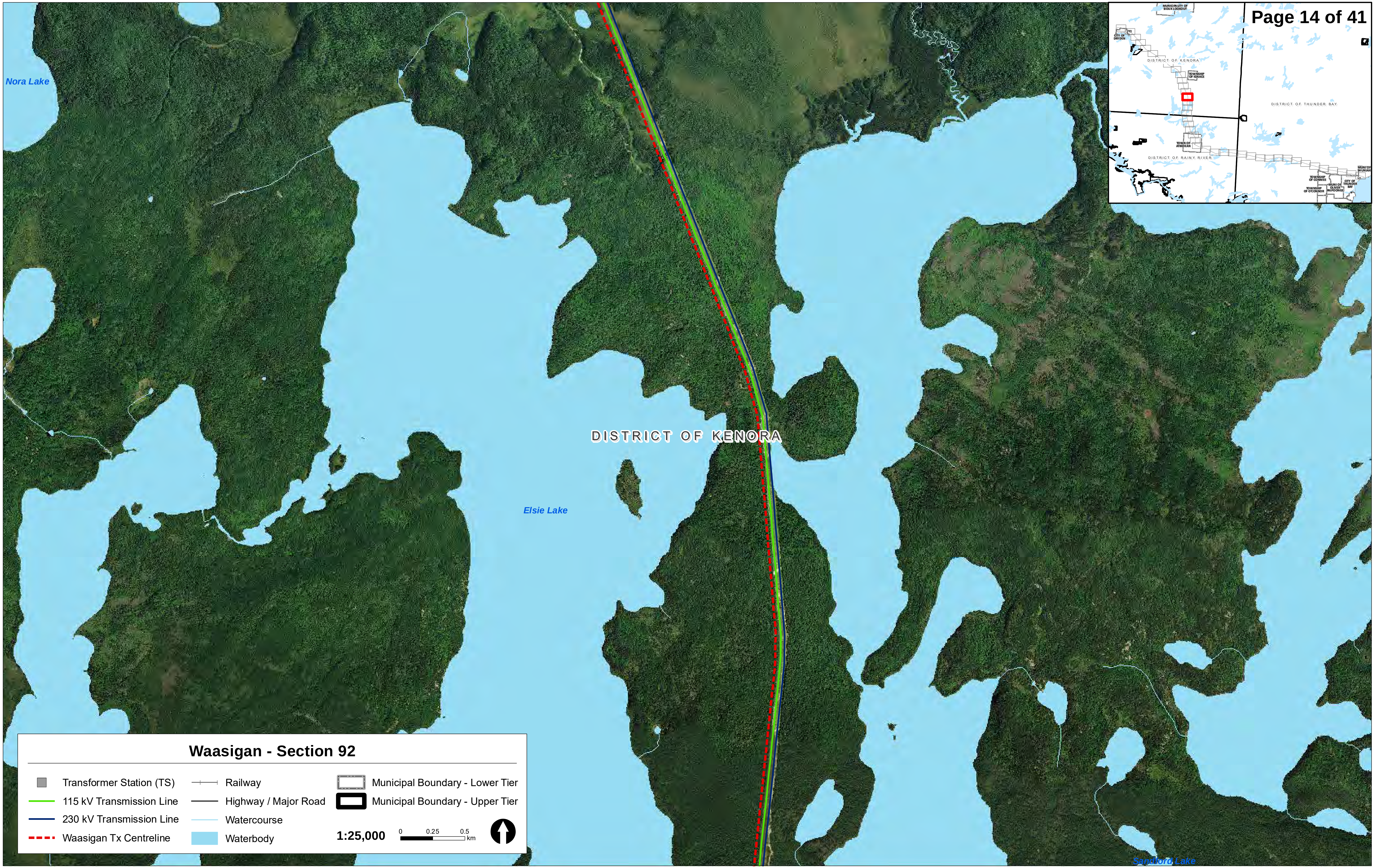

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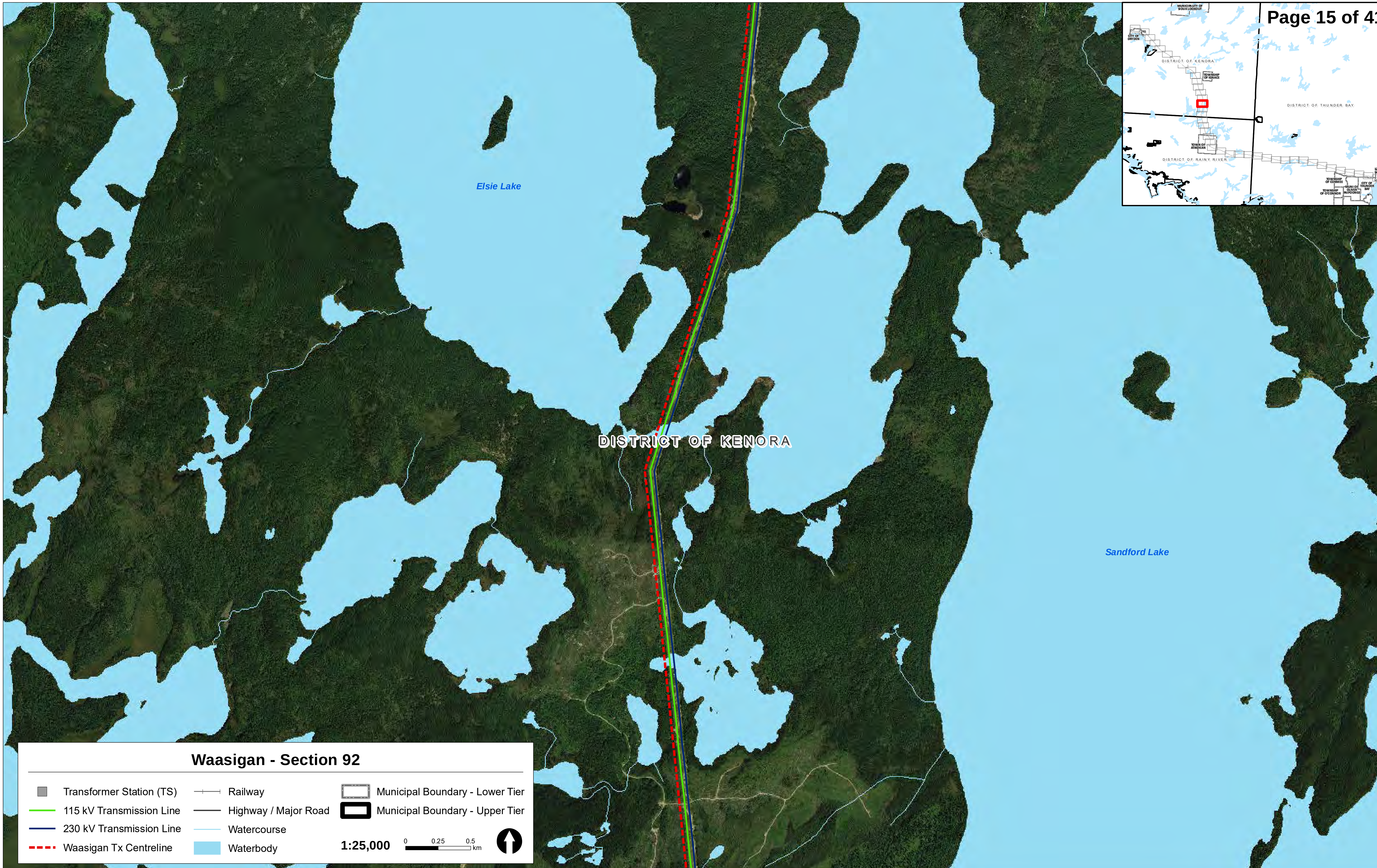

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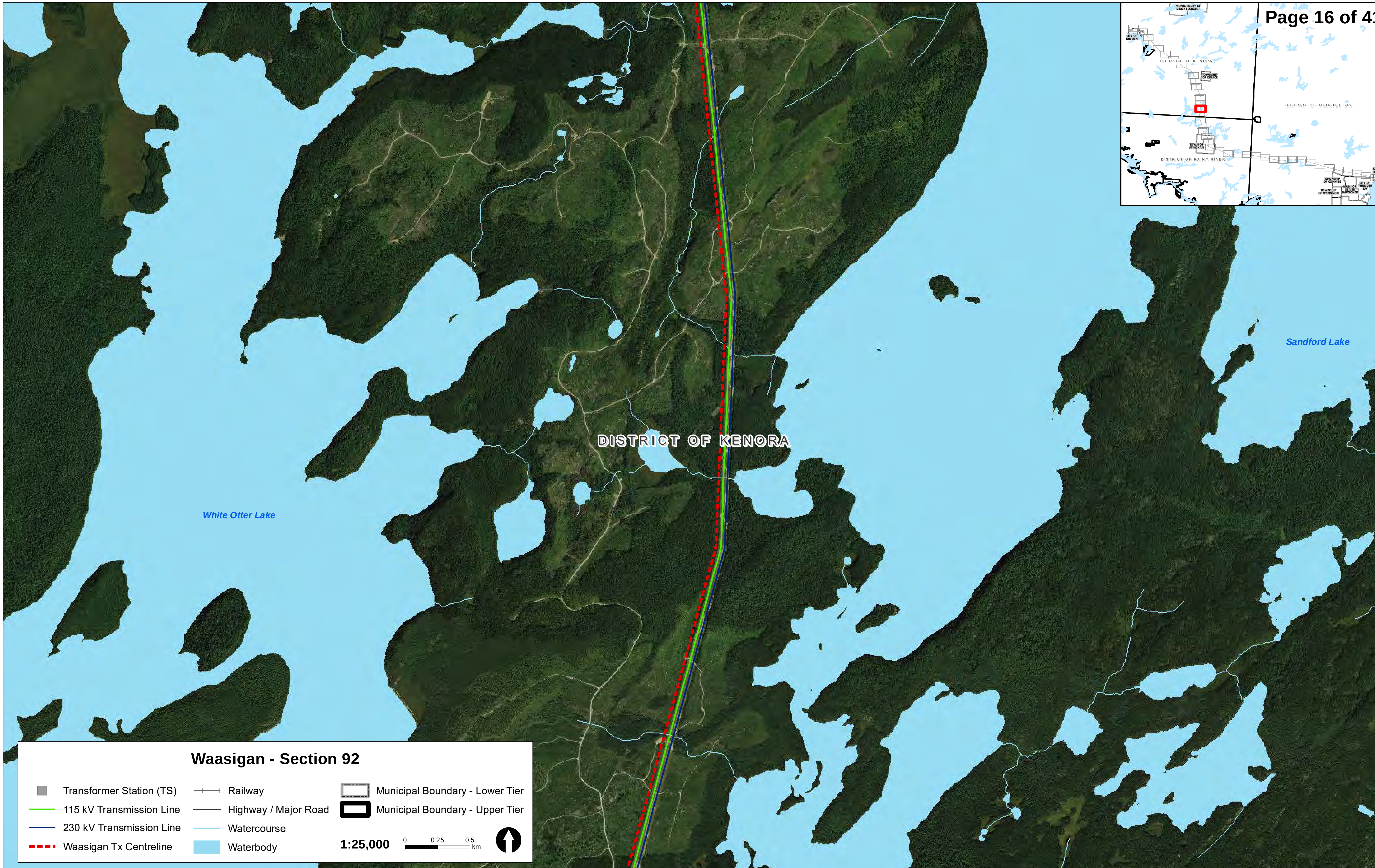

hydro one

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Date: May 26, 2023
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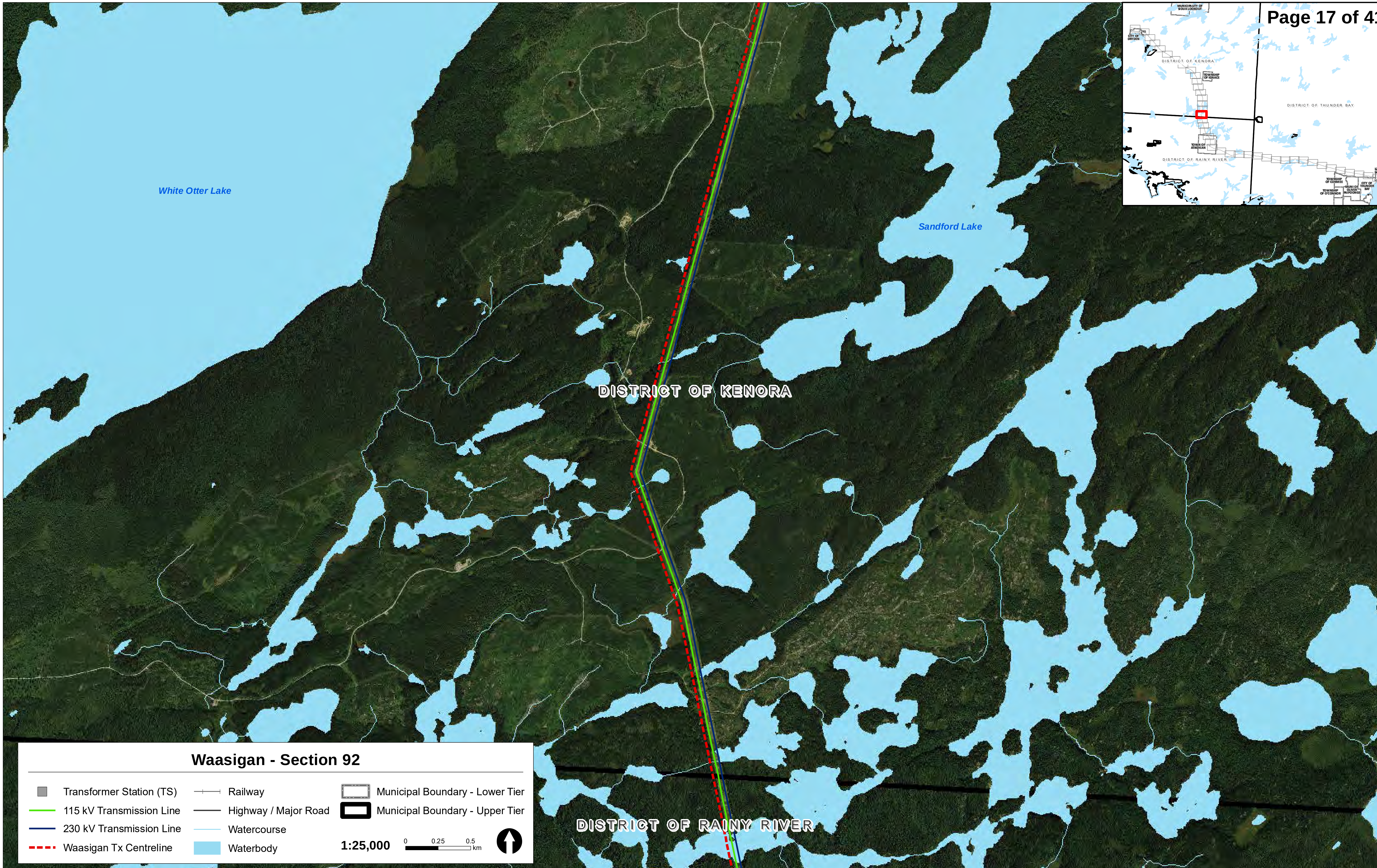

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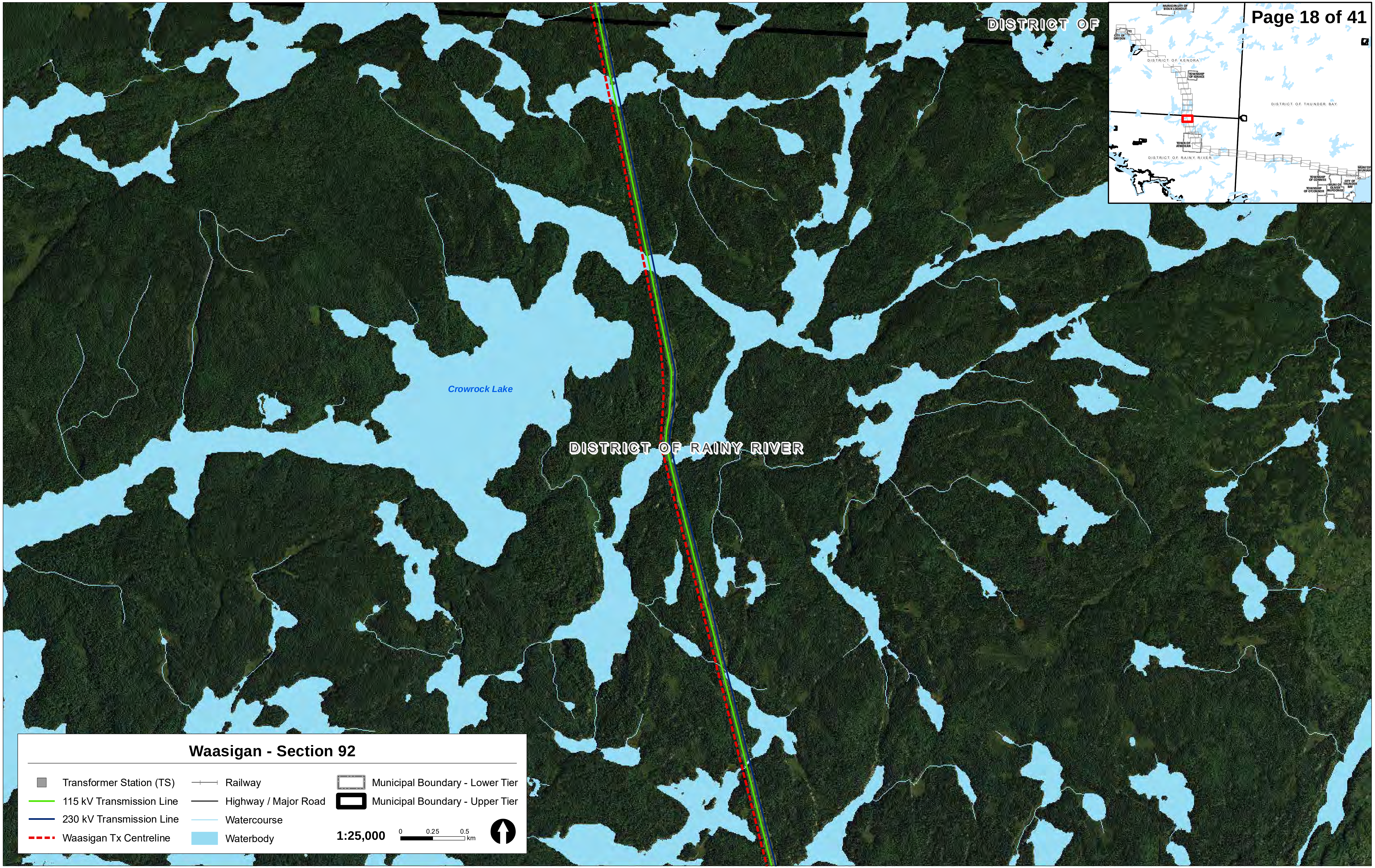

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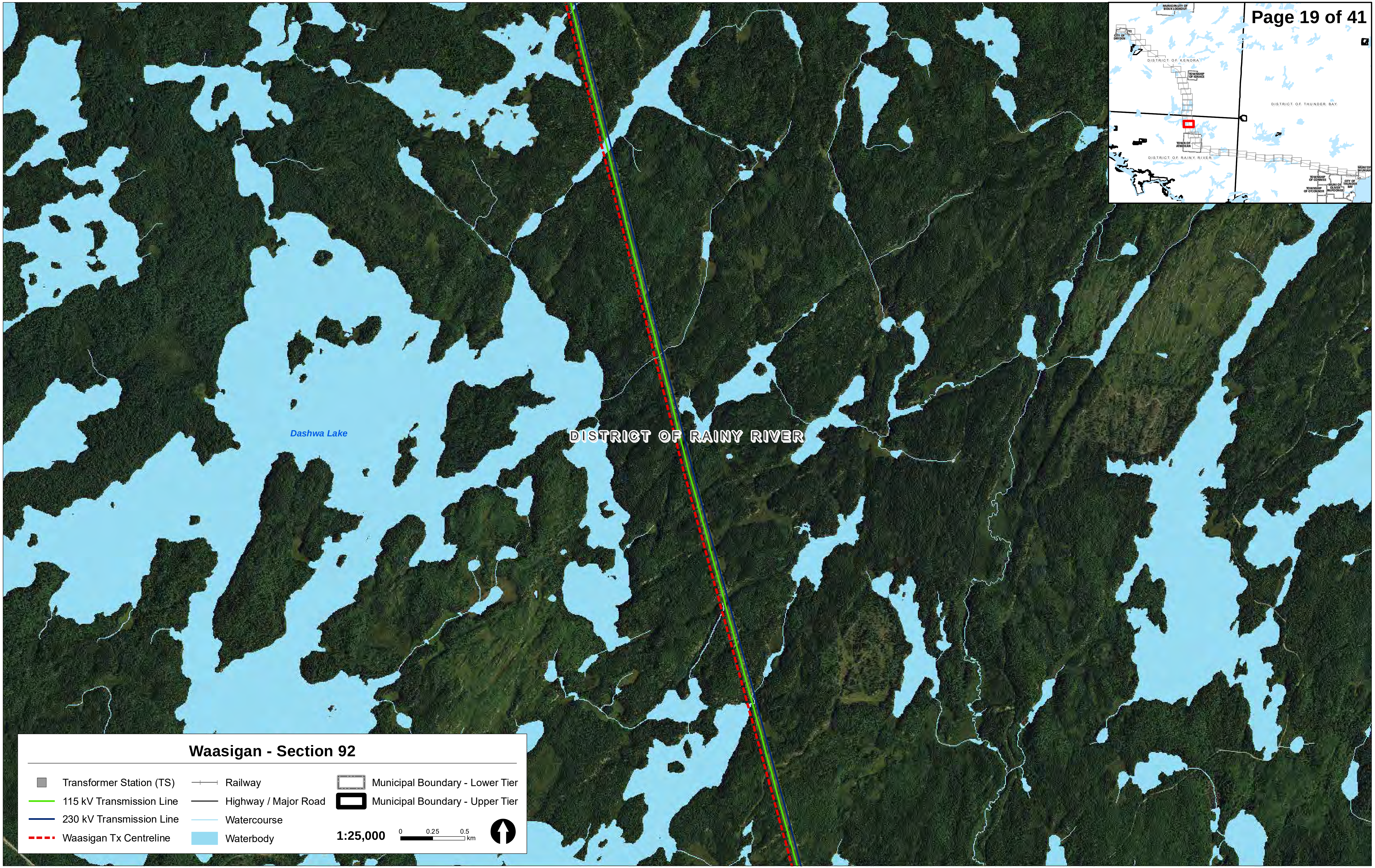

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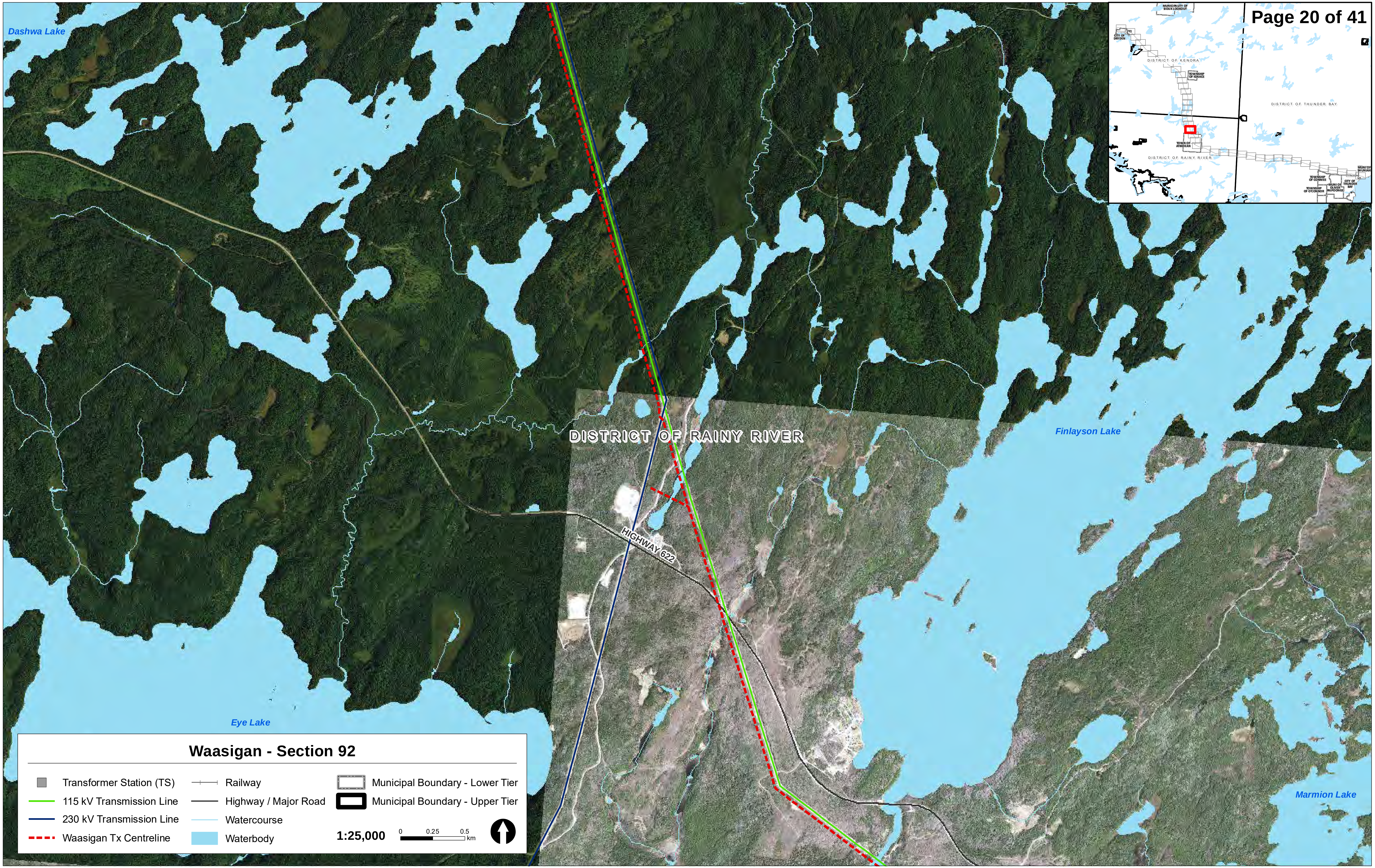

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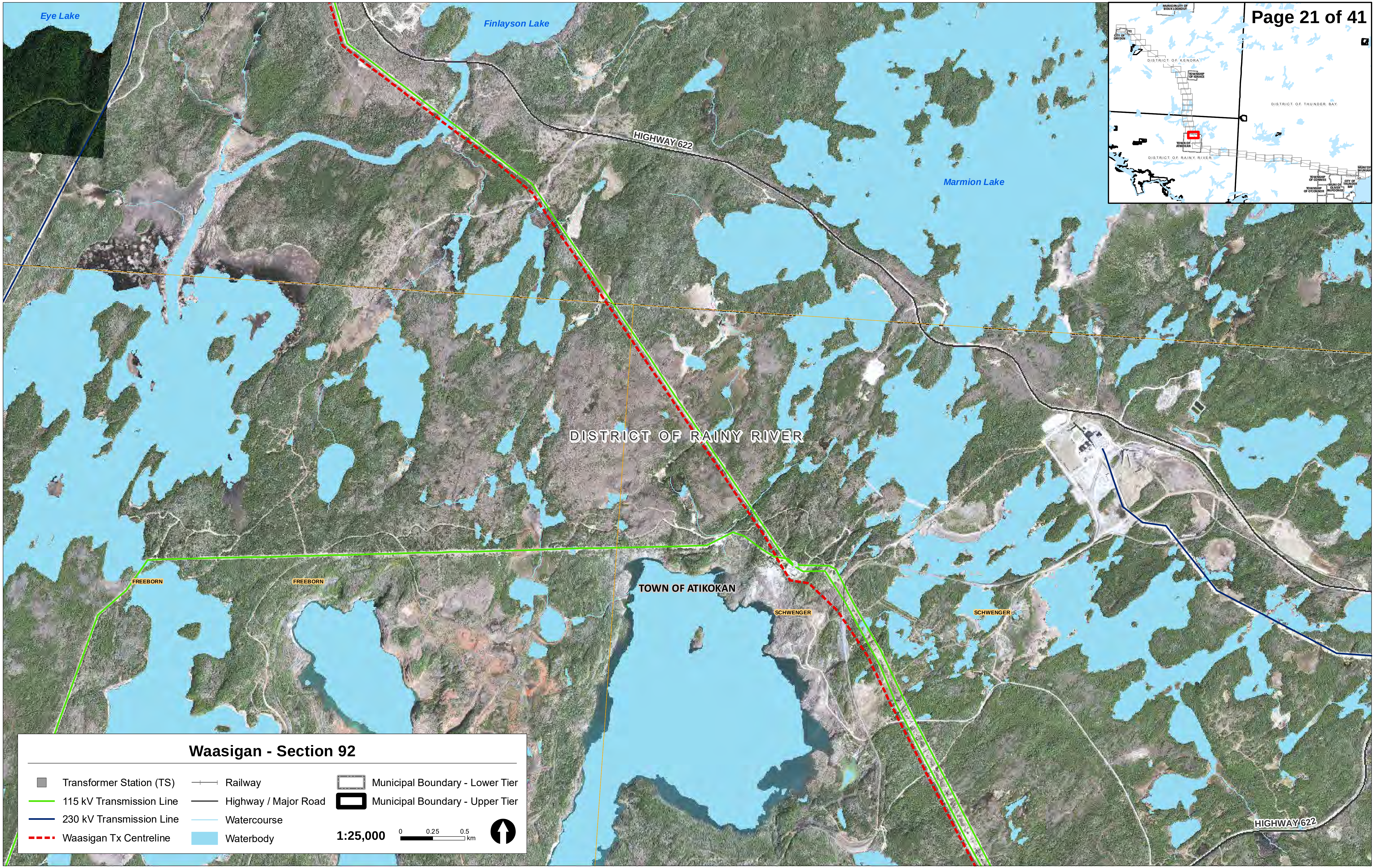

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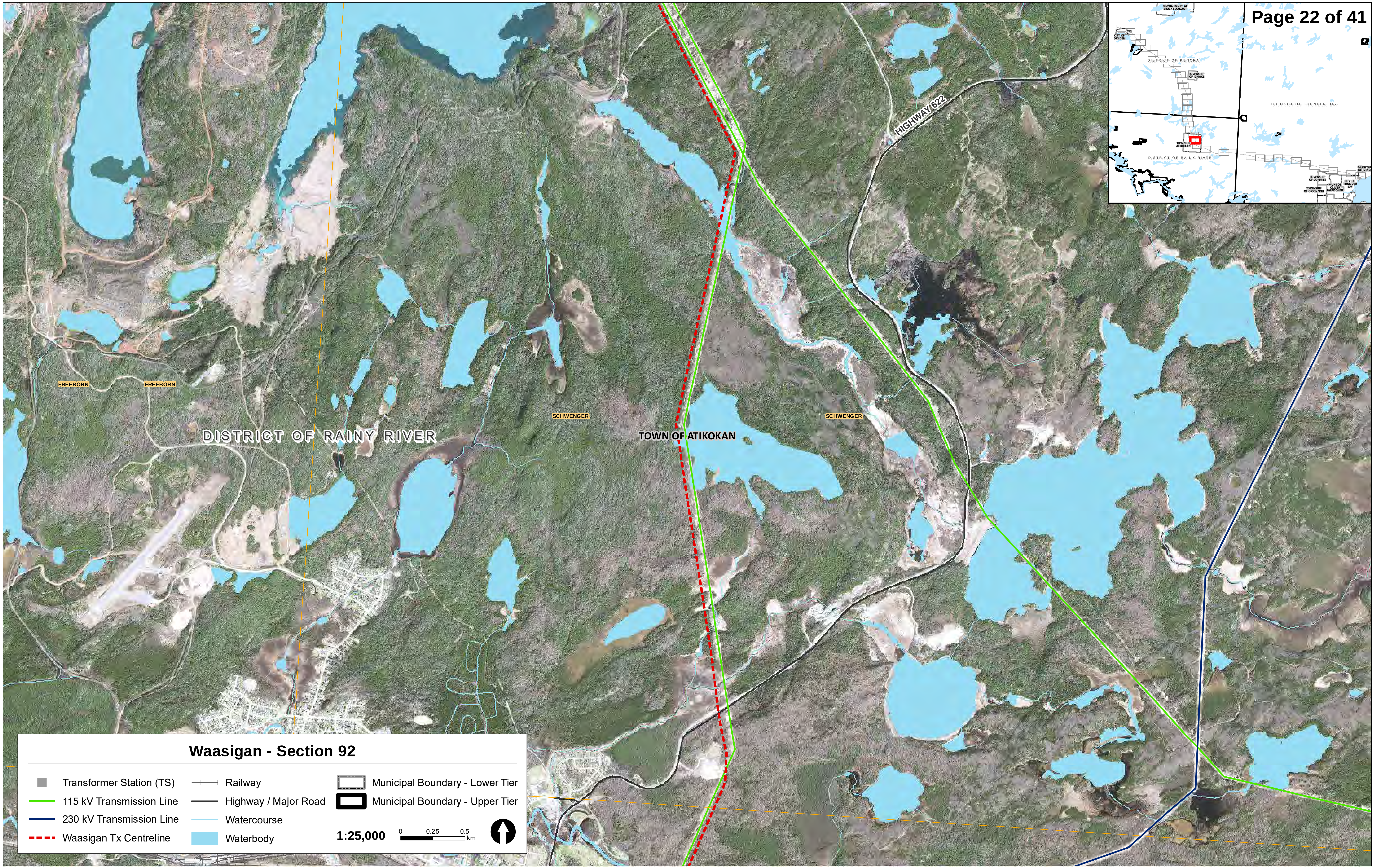

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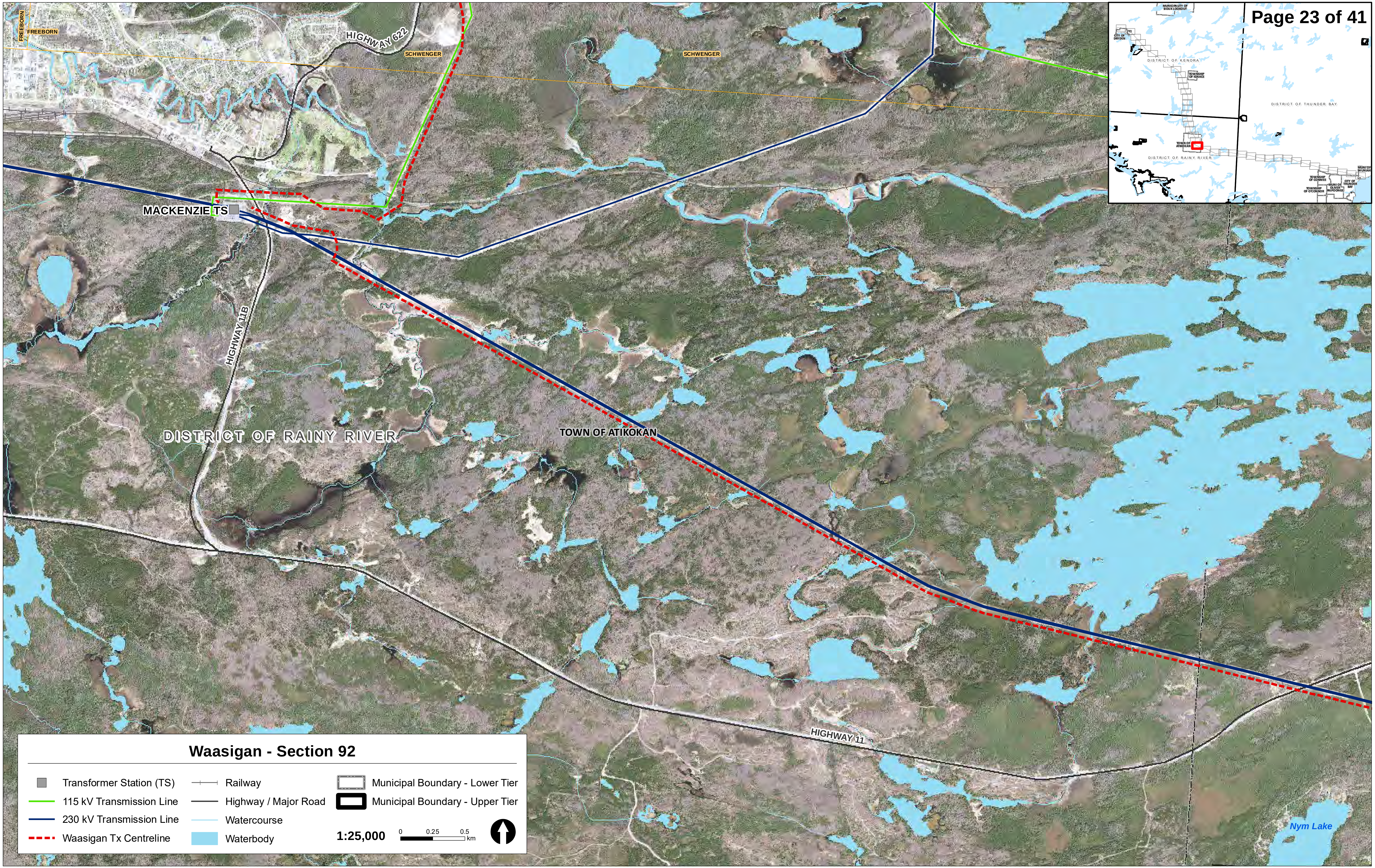

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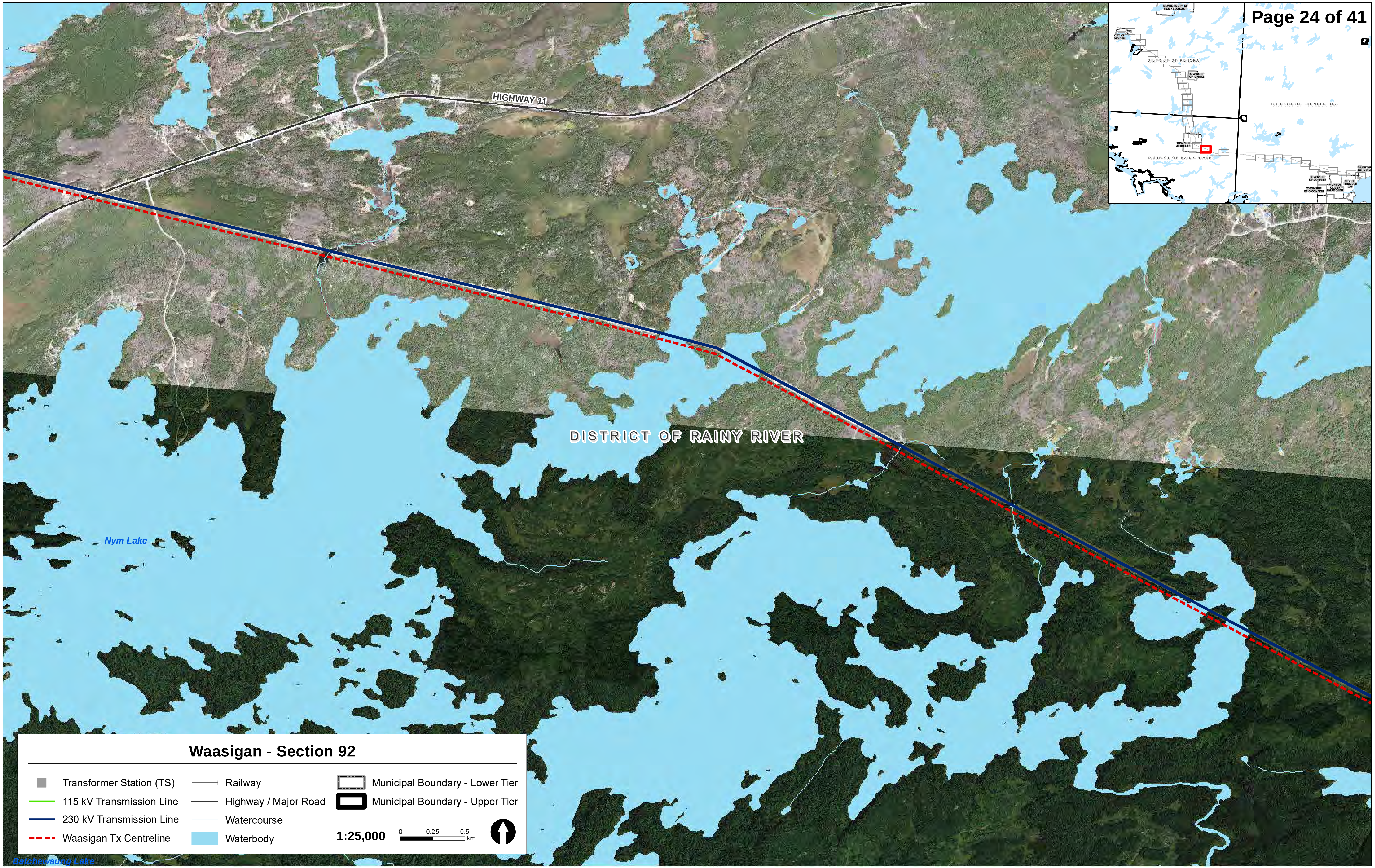

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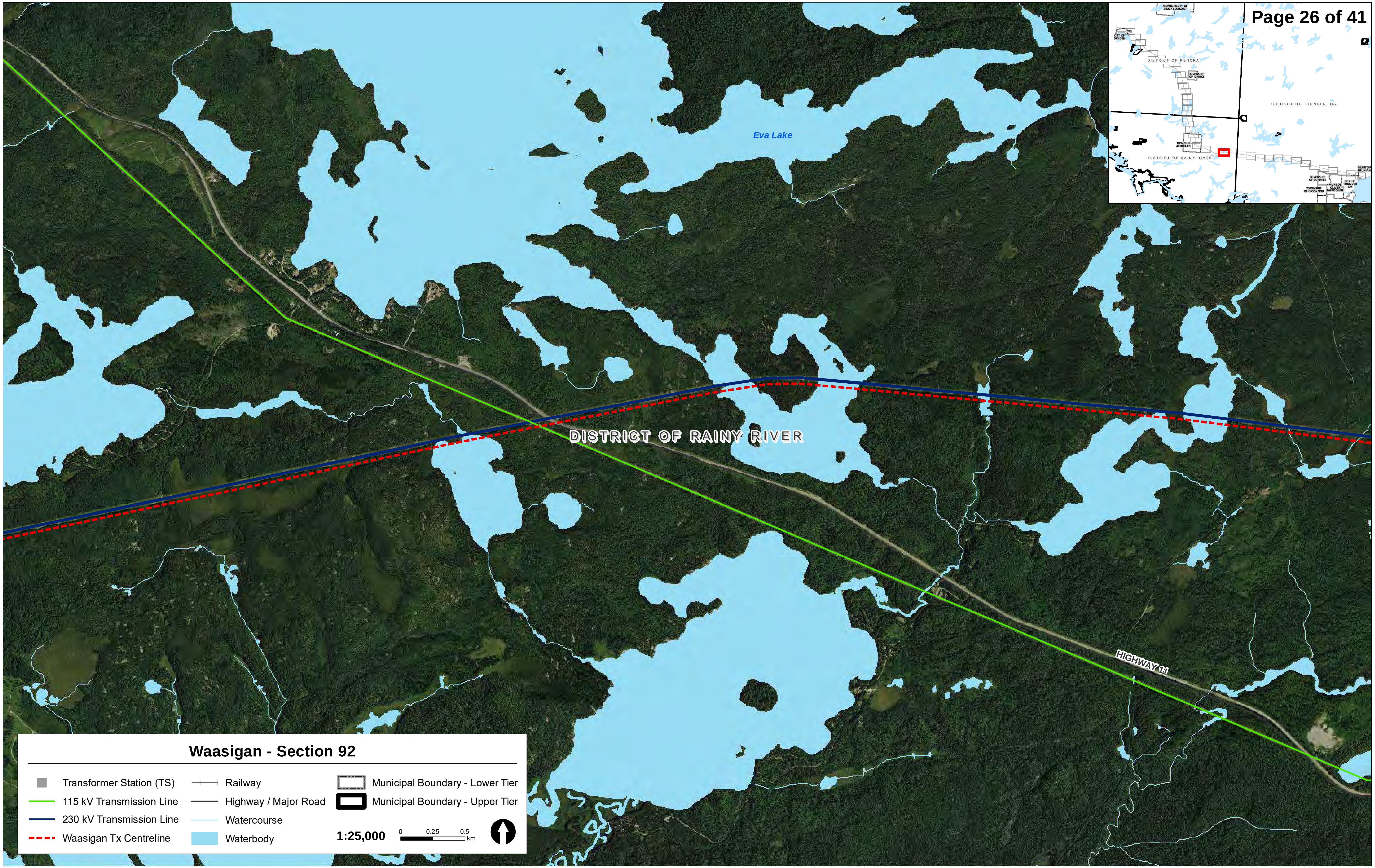

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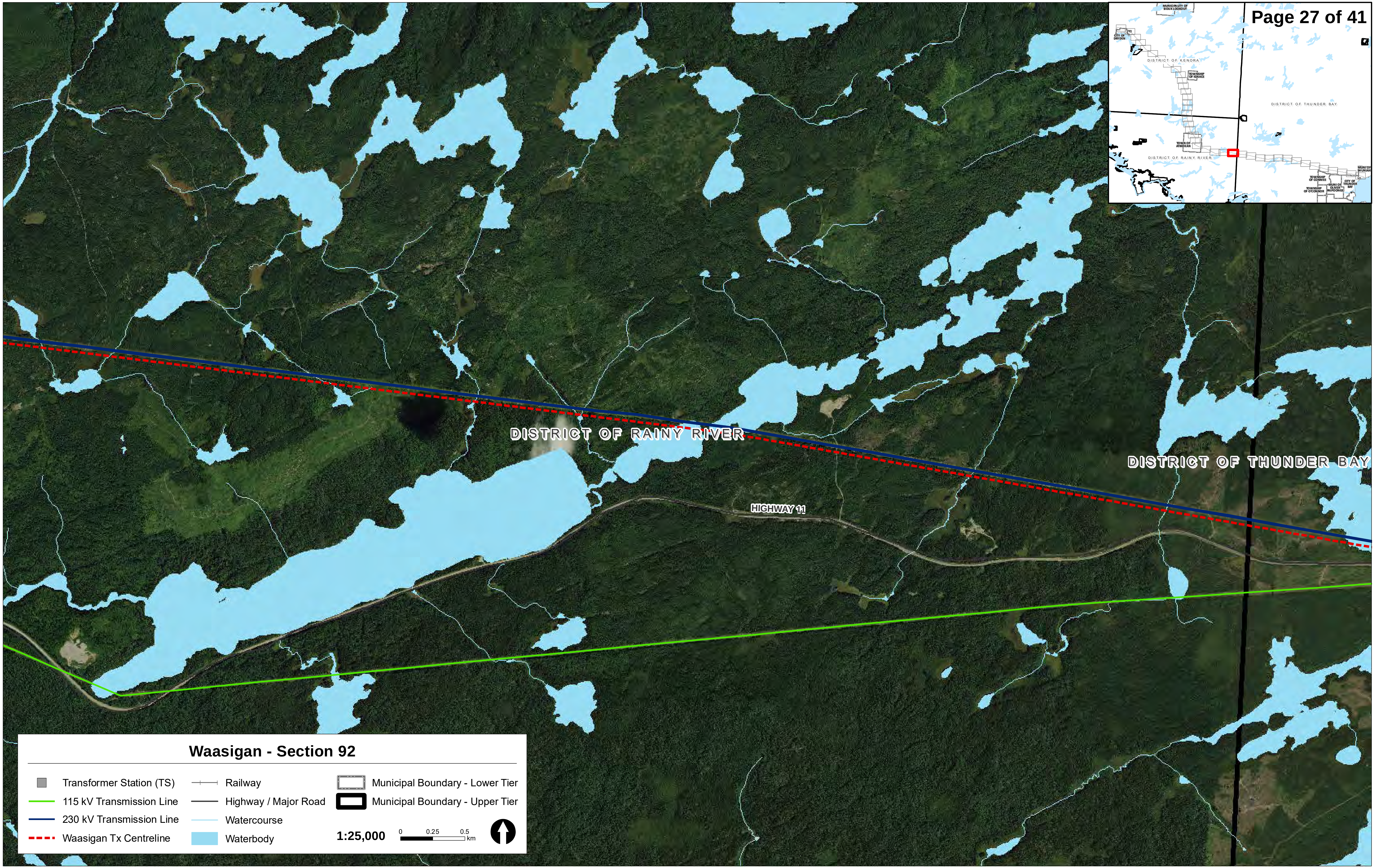

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Date: May 26, 2023
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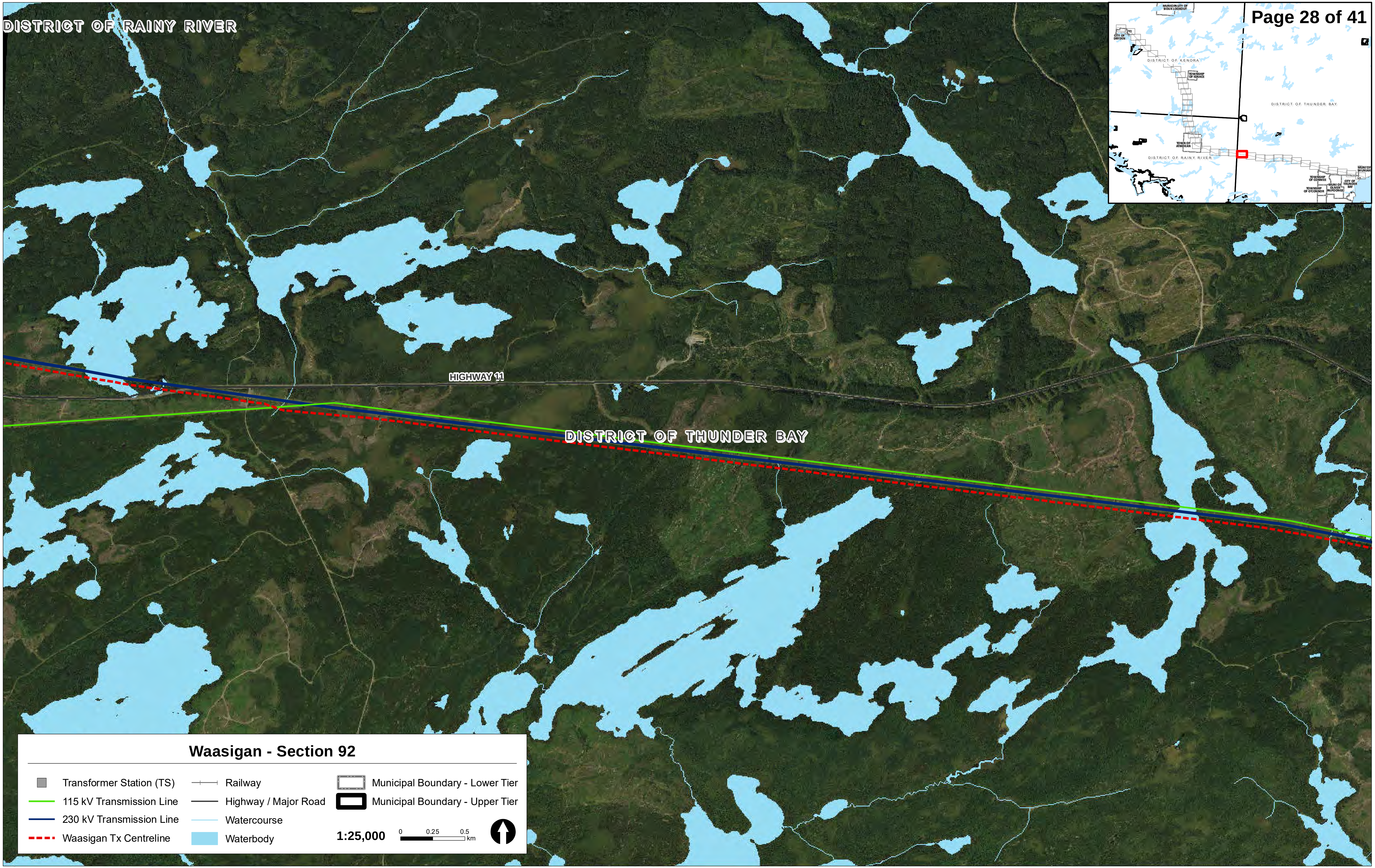

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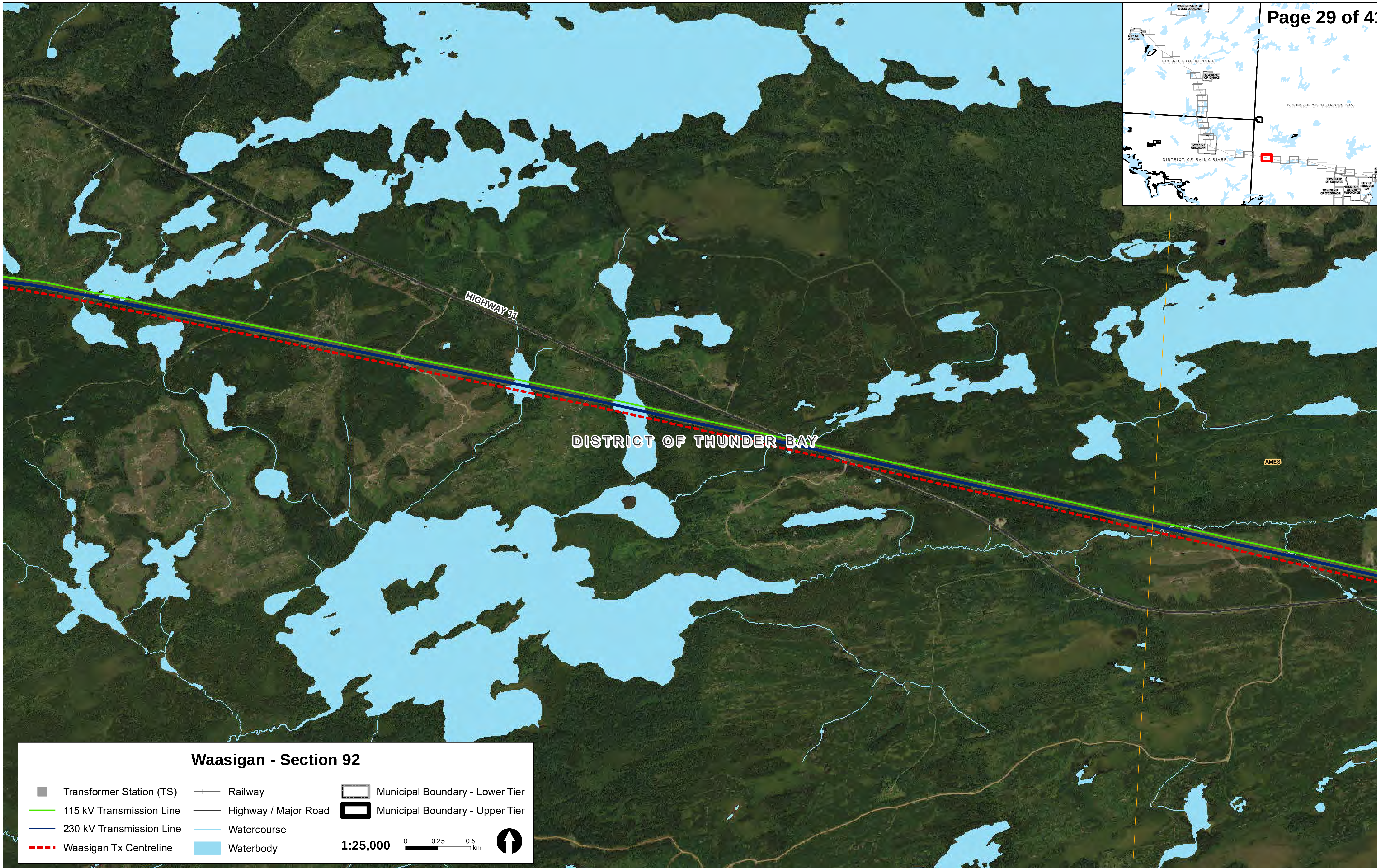

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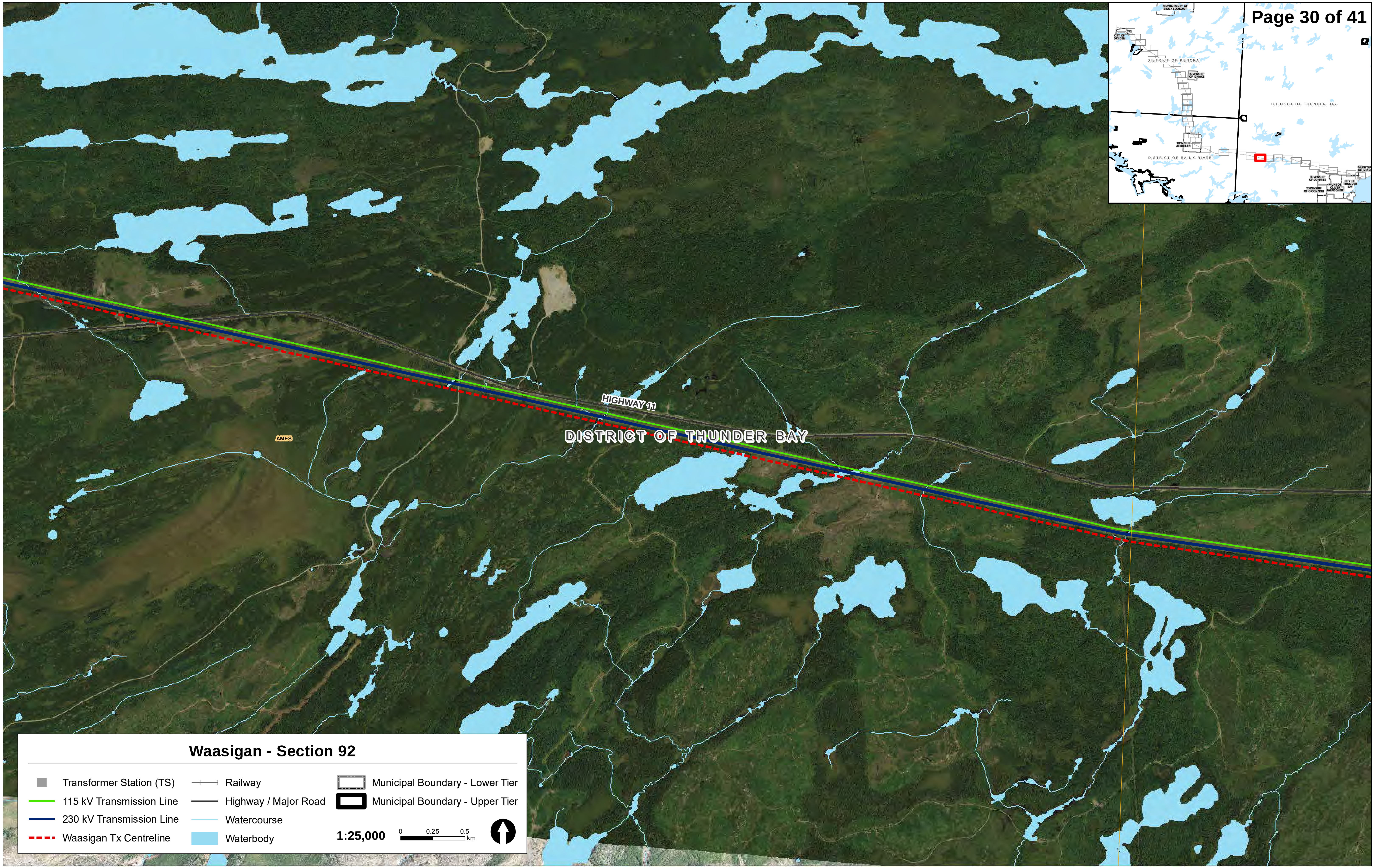

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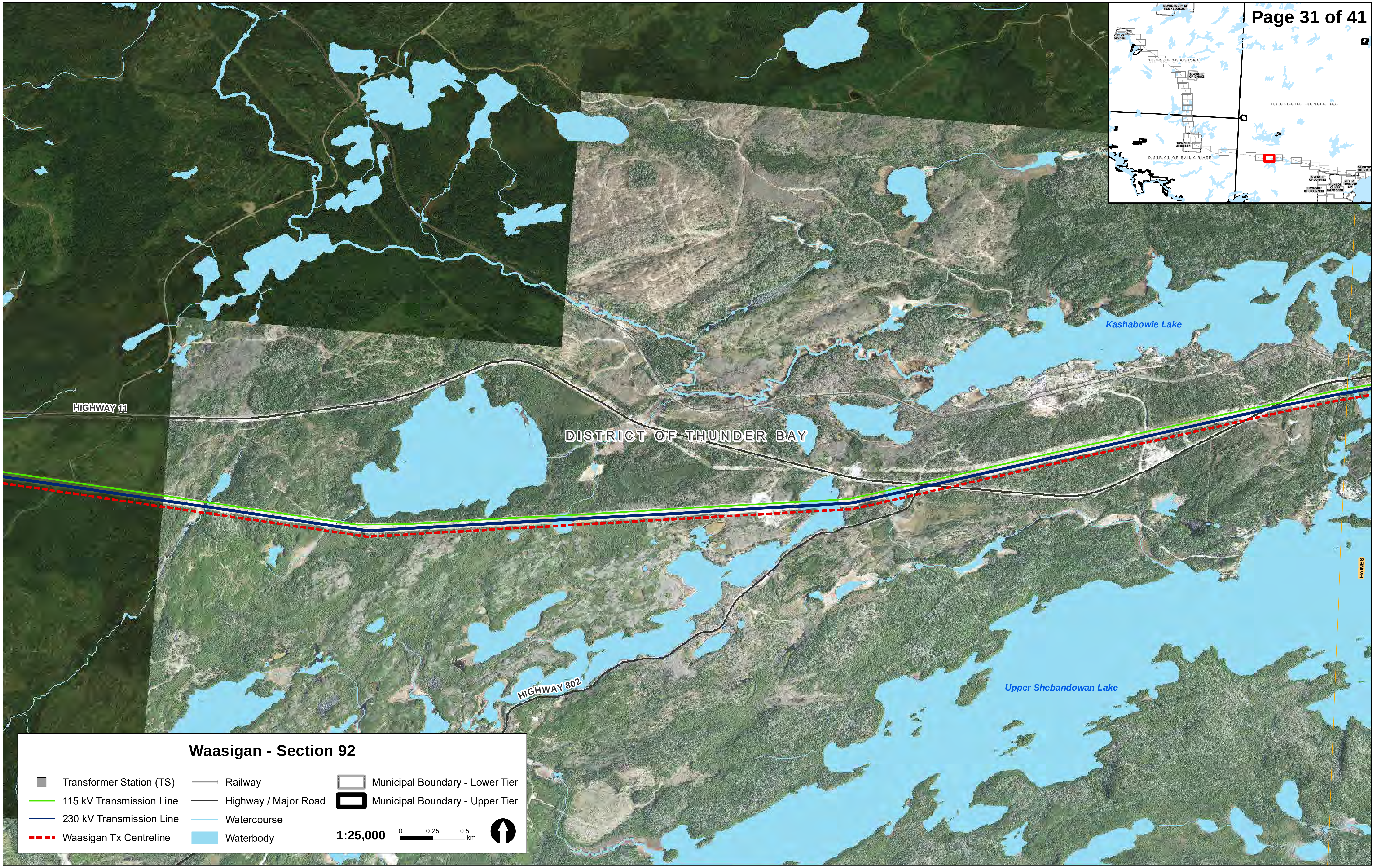

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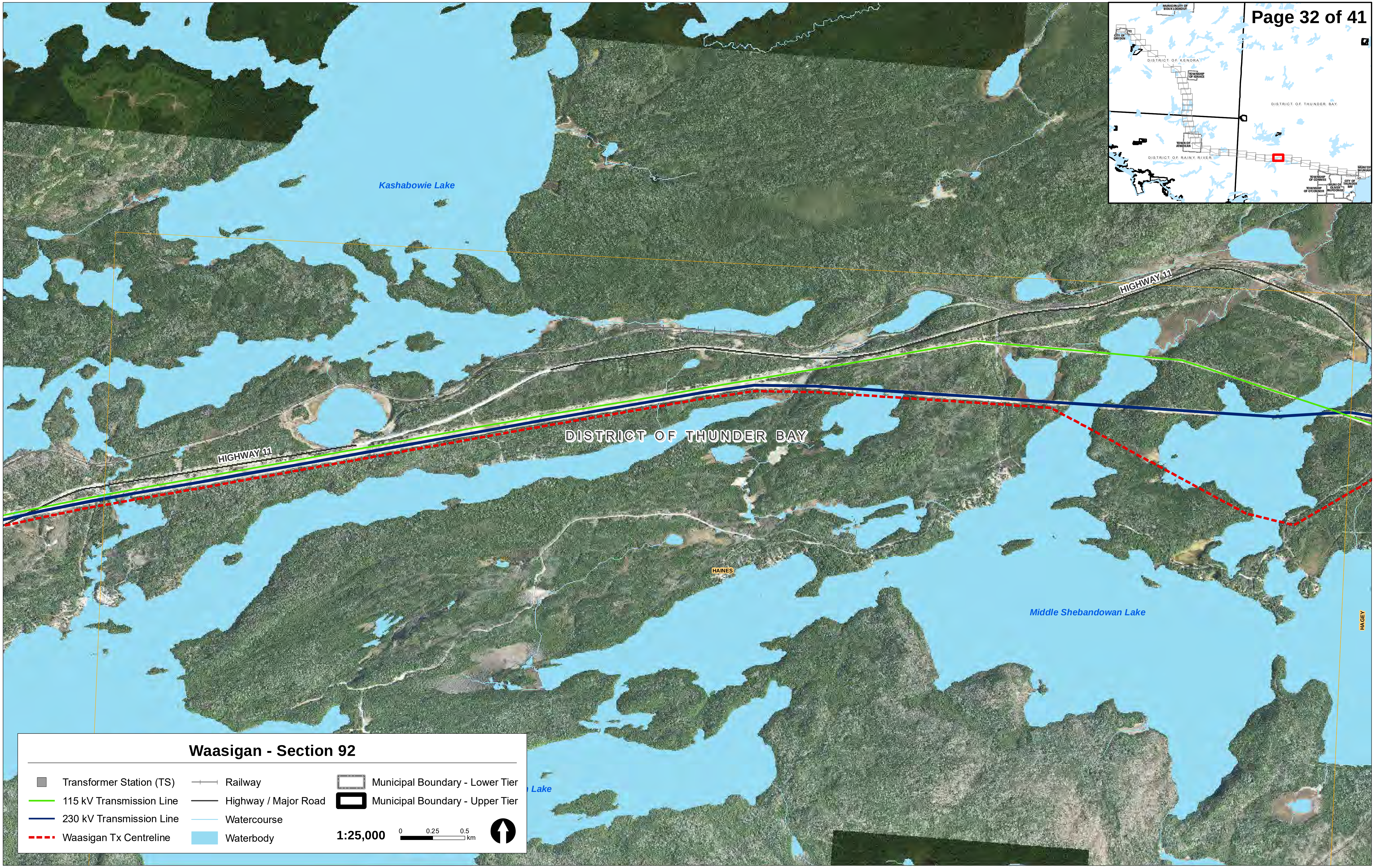

Waasigan - Section 92

Transformer Station (TS)	Railway	Municipal Boundary - Lower Tier
115 kV Transmission Line	Highway / Major Road	Municipal Boundary - Upper Tier
230 kV Transmission Line	Watercourse	
Waasigan Tx Centreline	Waterbody	

1:25,000 — 0 0.25 0.5 km

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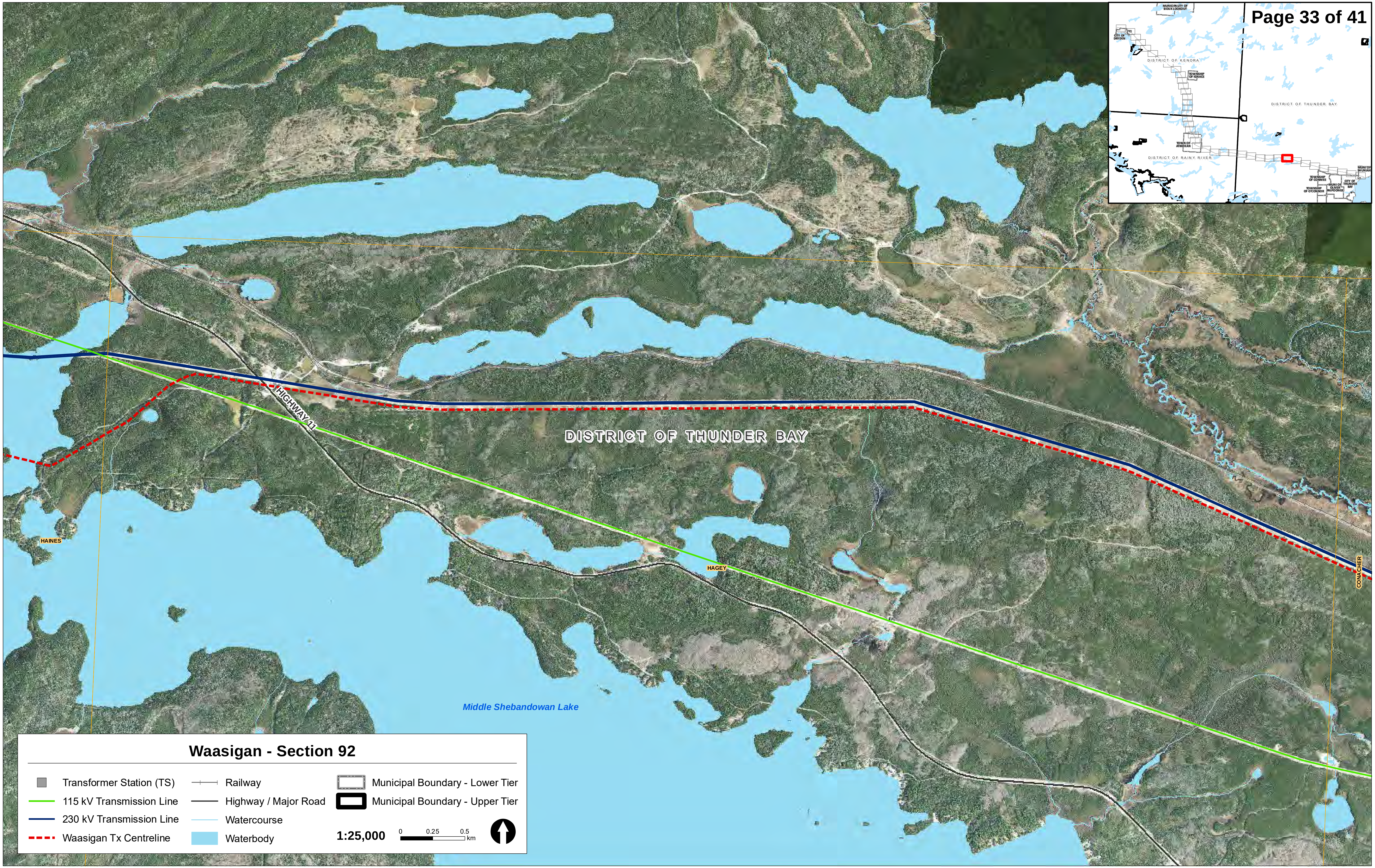

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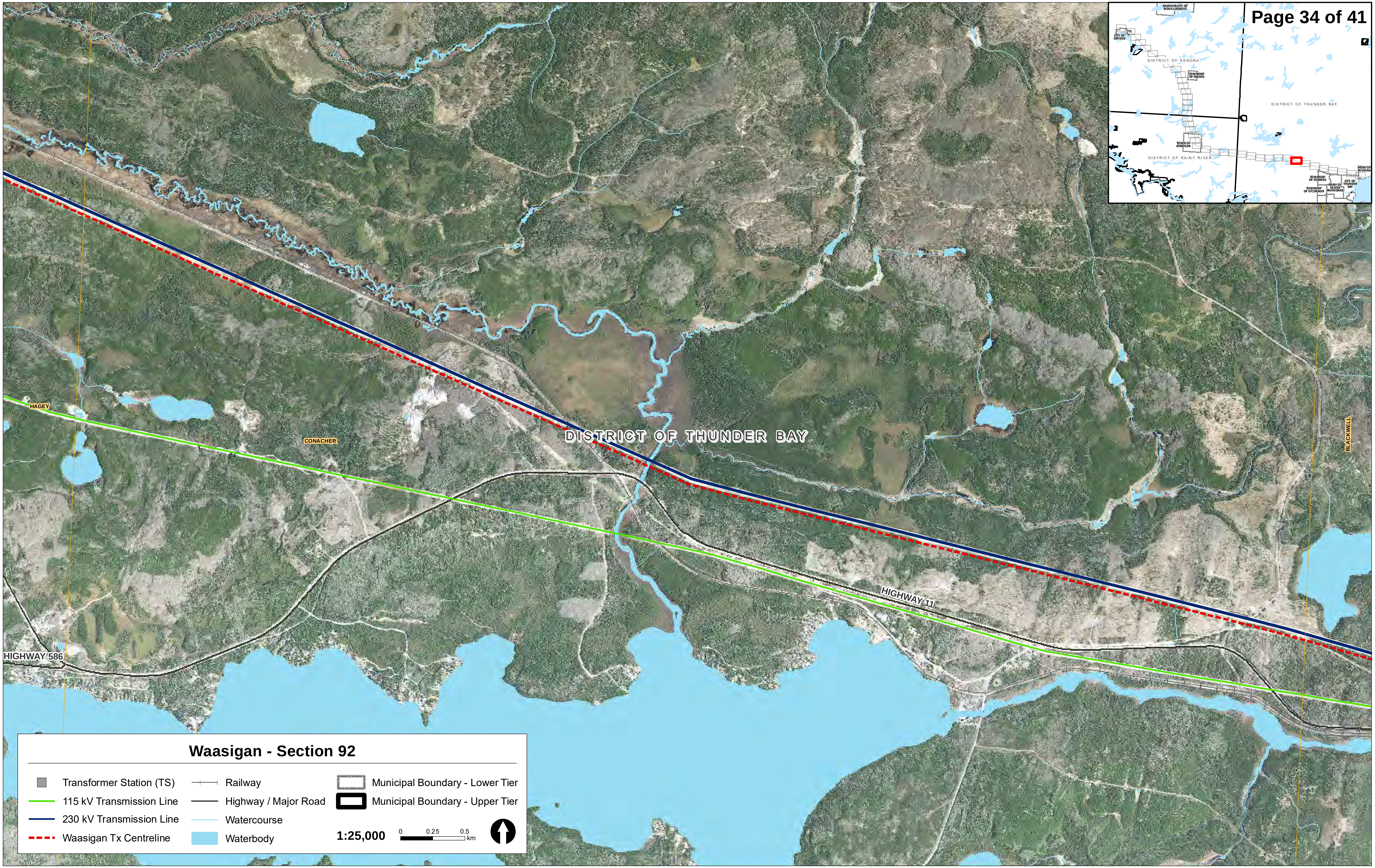

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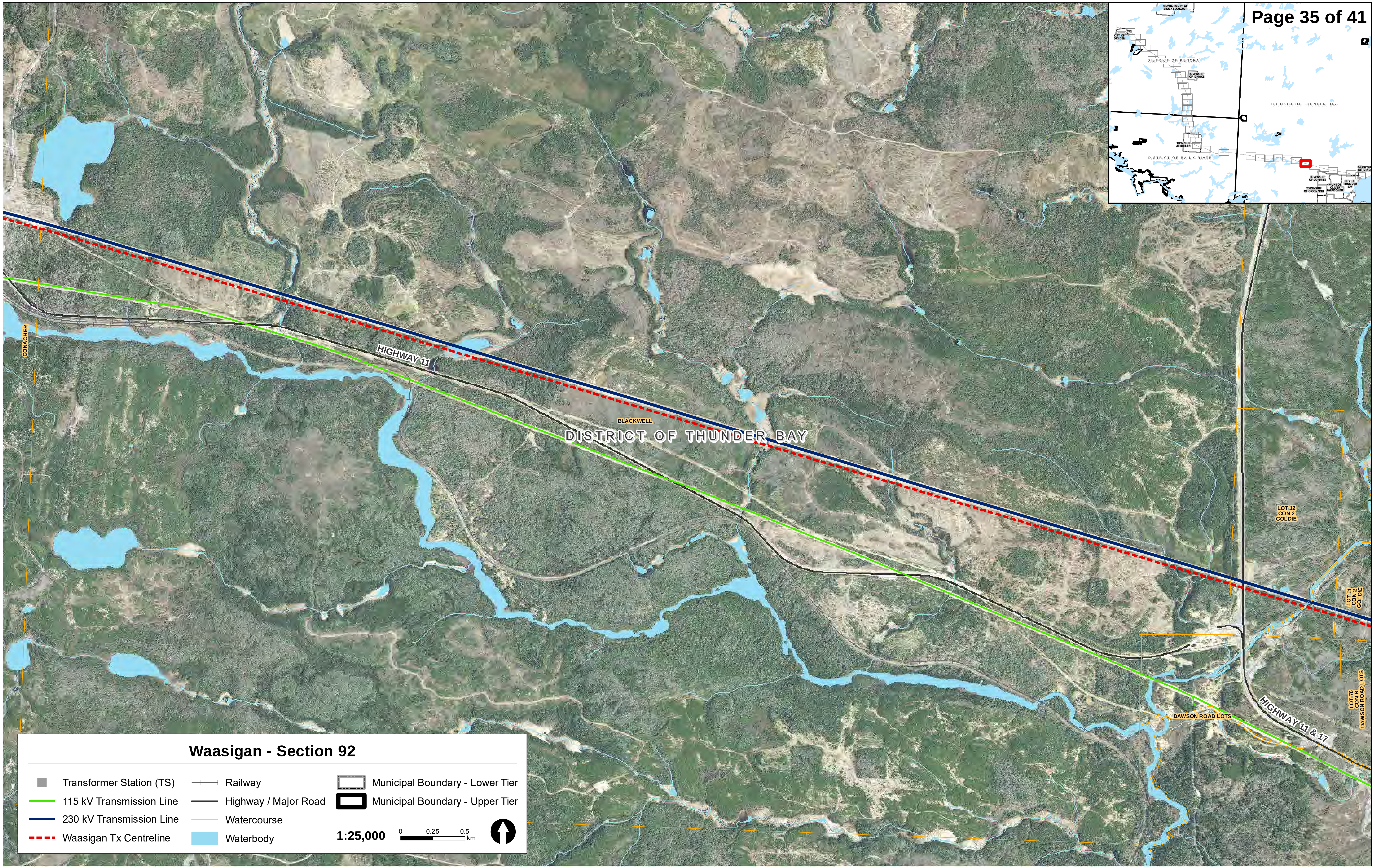

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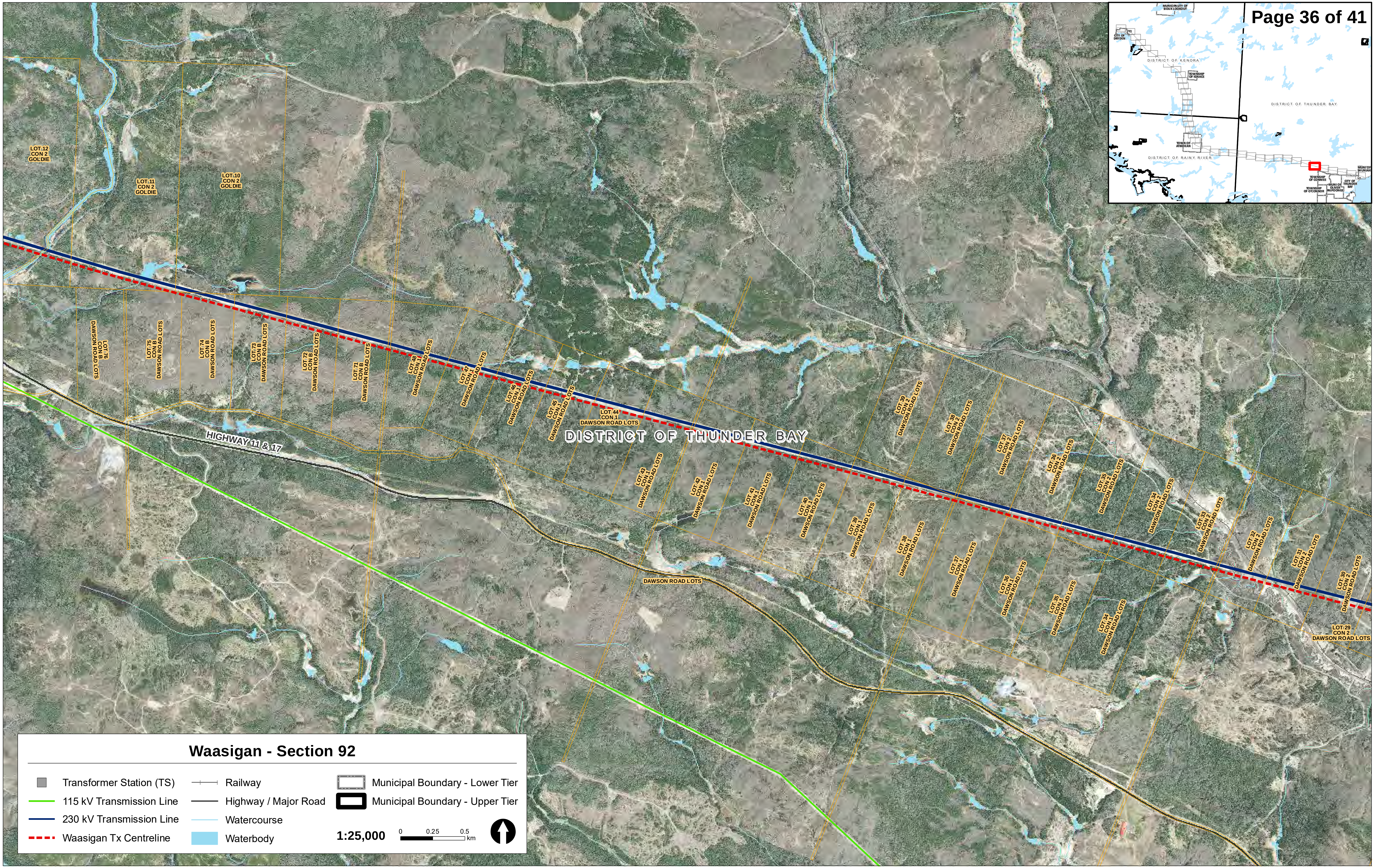

hydro one

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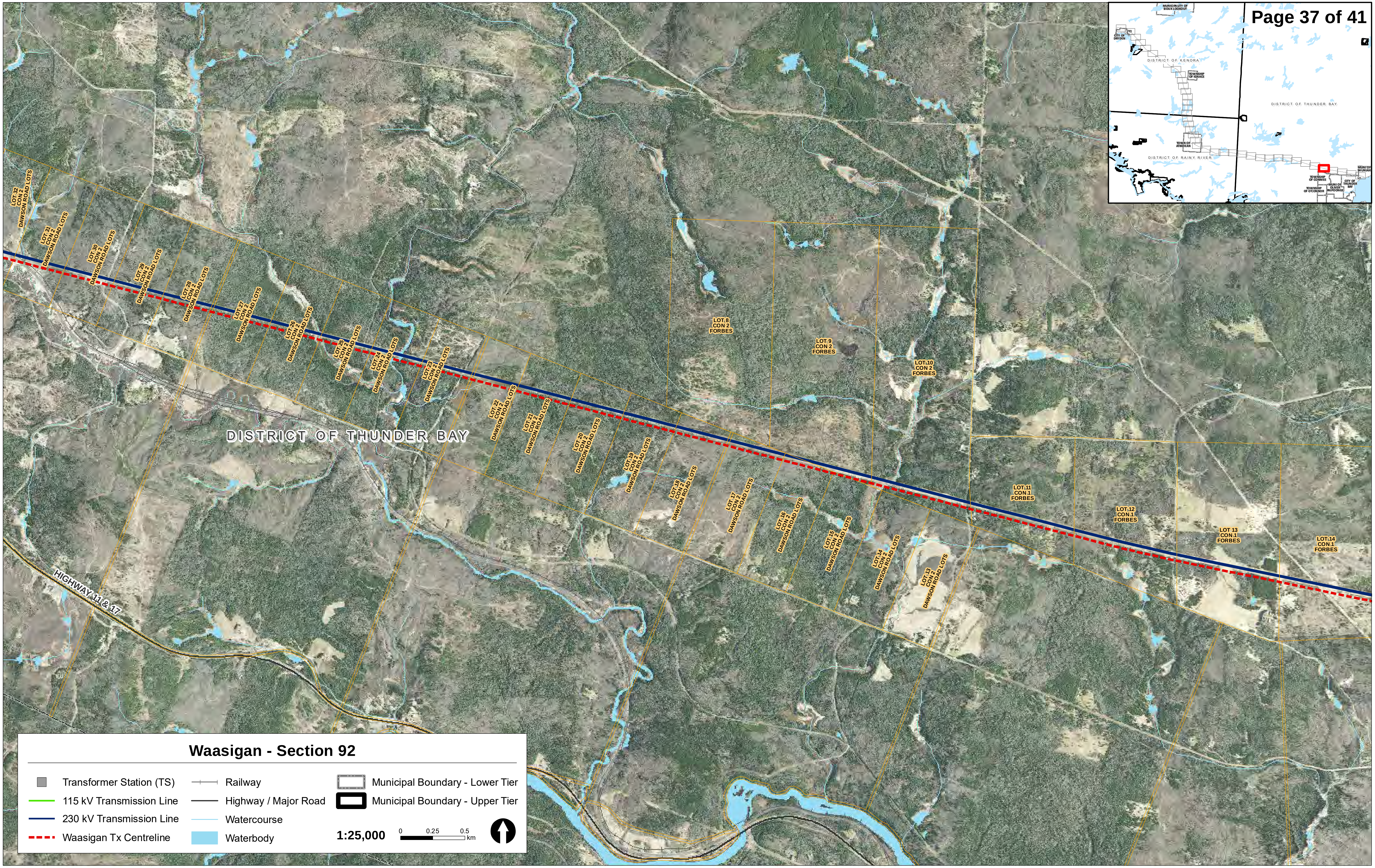

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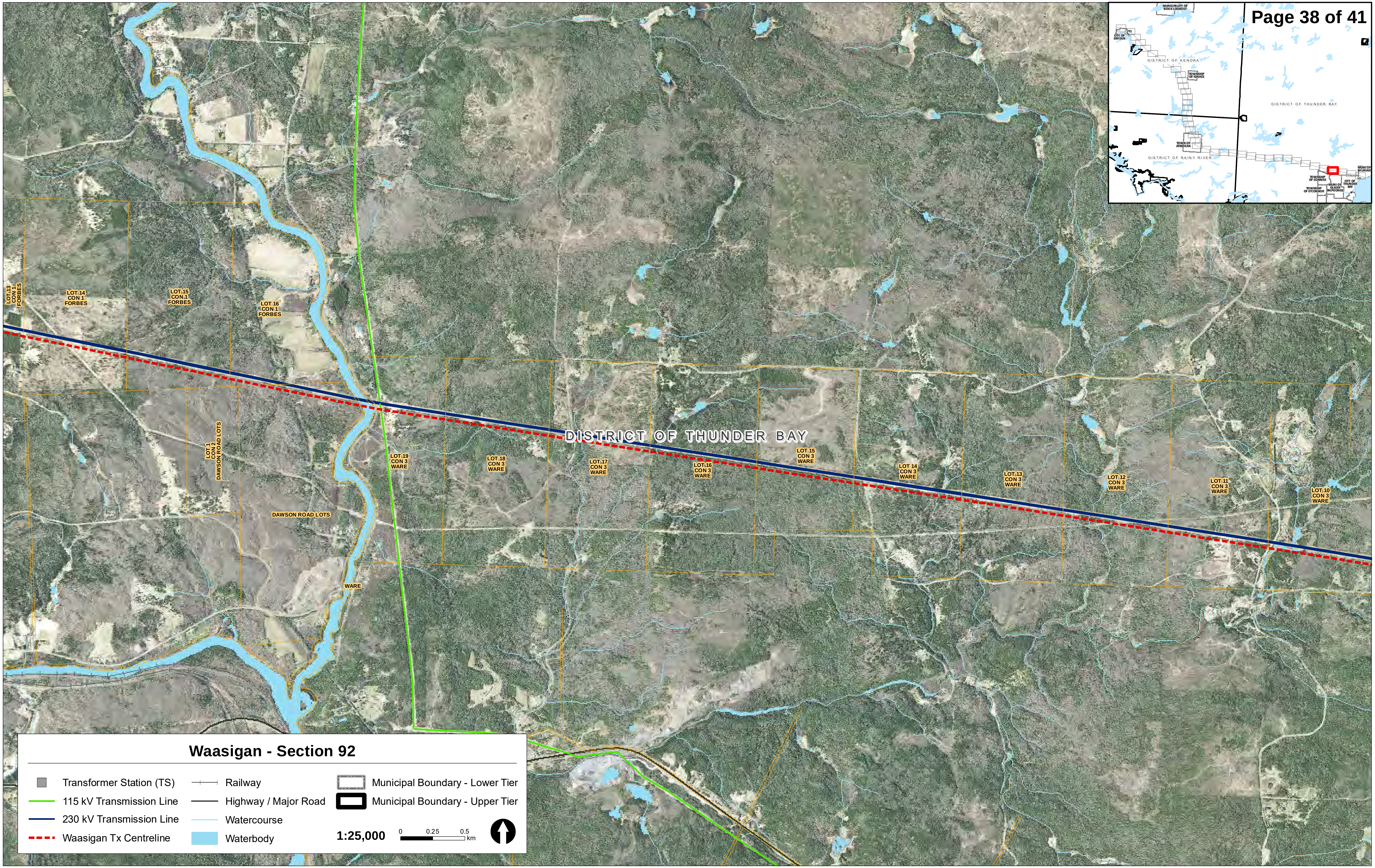

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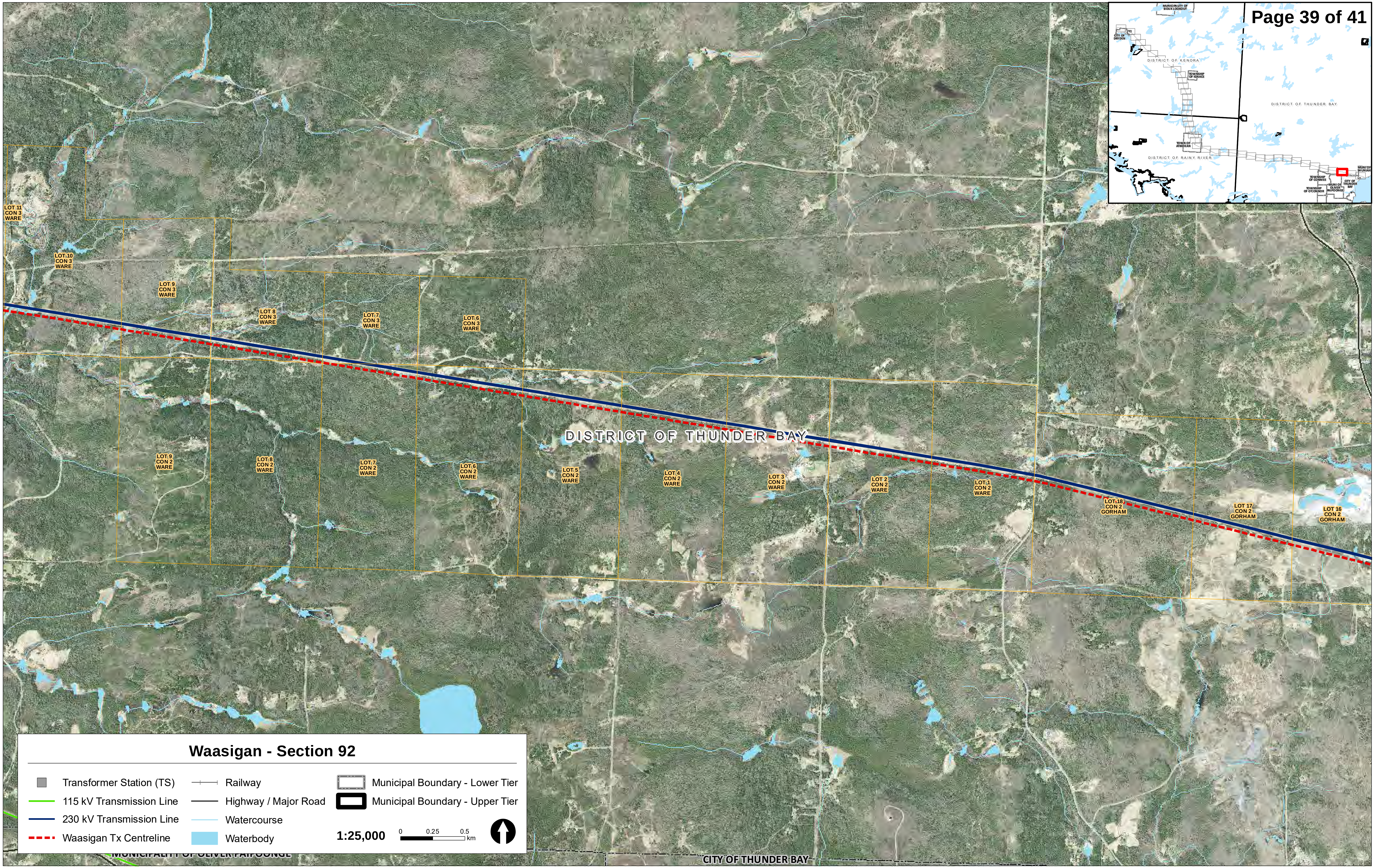

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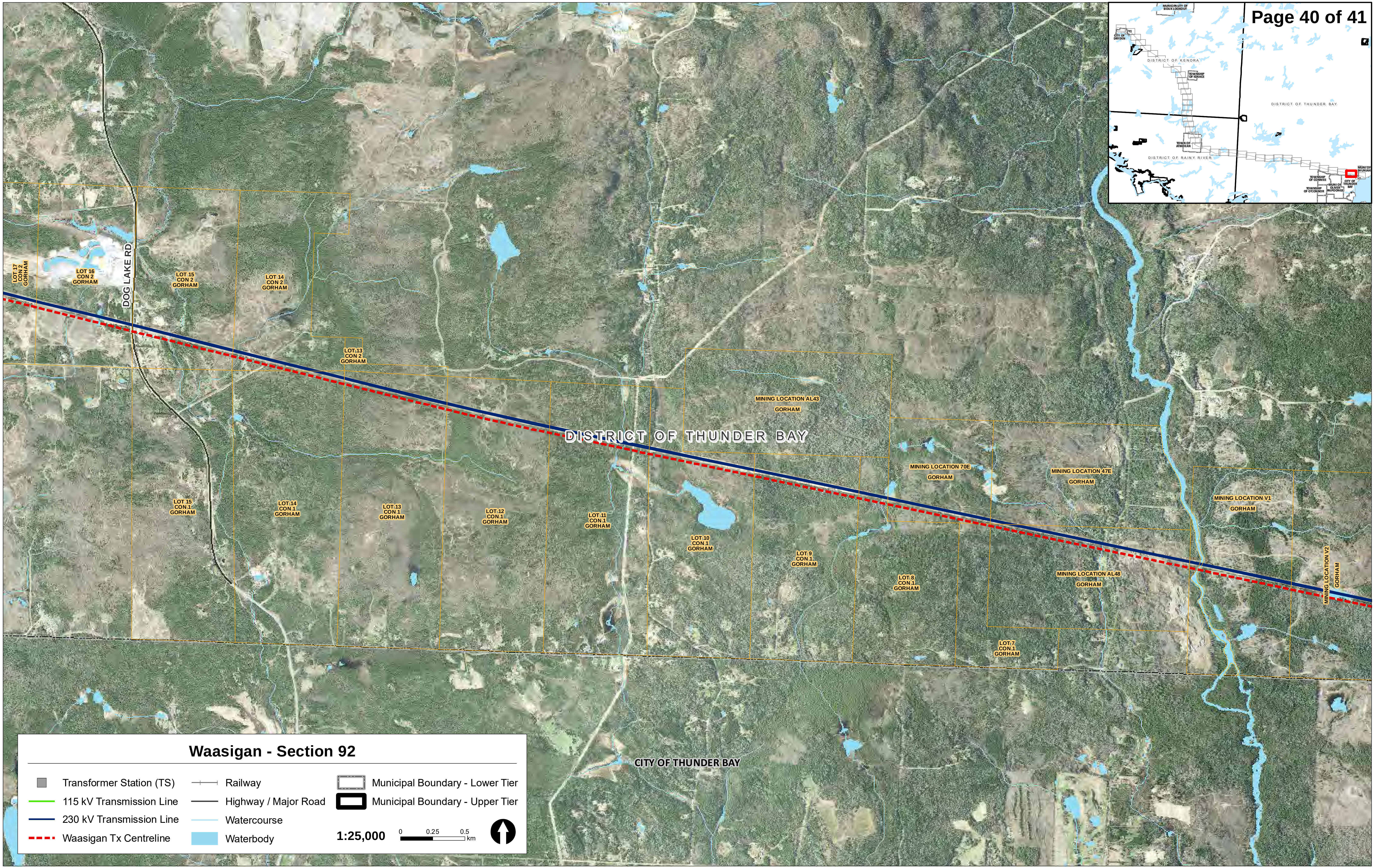

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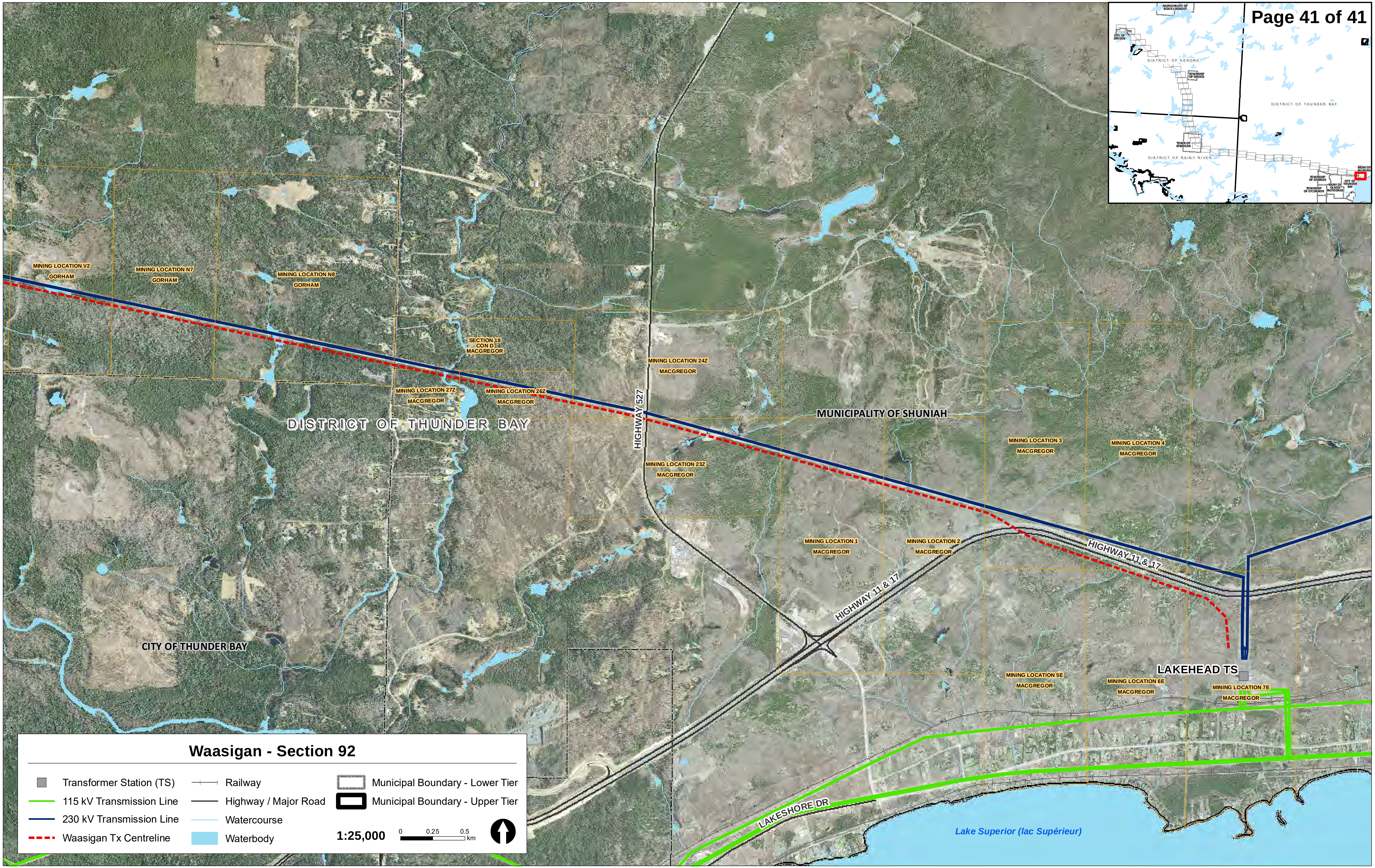

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OPERATIONAL DETAILS

The proposed facilities are in the districts of Thunder Bay, Rainy River and Kenora, Ontario. These facilities are part of the Ontario bulk transmission system and are critical circuit sections of the electrical system that allows management of flows towards and away from the Thunder Bay to Kenora areas. Hydro One Protection, Control and Telecom facilities installed as part of the Project will protect the new 230 kV transmission lines by detecting faults and isolating faulted elements. The future limited partnership will enter into Operating Service Agreements such that the proposed facilities will be monitored and operated by Hydro One's ISOC as directed by the IESO. The terminal stations for the proposed facilities are Lakehead TS, Mackenzie TS and Dryden TS as aforementioned in the Application.

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LAND MATTERS

1.0 THE ROUTE

The Waasigan Project is best described in two distinct phases, due to the timing of completion and in-service. Hydro One is seeking approval of both Project phases in this Application.

Phase 1

The first phase of the Waasigan Project involves the construction of a new 230 kV double circuit transmission line that is 190 km in length extending from Hydro One's Lakehead TS in the Municipality of Shuniah along the existing 230kV transmission line corridor near Highway 11 and 17 out of Shuniah and into Hydro One's Mackenzie TS in the Town of Atikokan.

Phase 2

The second phase of the Project involves the construction of a new 230 kV single circuit transmission line that is 170 km in length extending from Hydro One's Mackenzie TS in the Town of Atikokan along the existing 230 kV transmission line corridor near Highway 622 and Highway 17 into Hydro One's Dryden TS, located in the City of Dryden.

The new transmission corridor will be approximately 46 metres[1] wide and will parallel an existing transmission line, taking advantage of the existing ROW to the extent possible. Utilizing existing infrastructure and facilities is consistent with the *Ministry of Municipal Affairs and Housing Provincial Policy Statement, 2020*[2] under the *Planning Act* specifically utilizing existing utility ROWs where achievable. The new transmission corridor passes through primarily Crown, Municipal and privately held lands.

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[1] Equivalent to 150 feet
[2] Sections 1.6.8.4 and 1.6.8.5

2.0 DESCRIPTION OF LAND RIGHTS

Independent of the conventional land rights required from private landowners and federal, provincial and municipal authorities as described below, the Applicant respects the Treaty, Aboriginal and Inherent rights of Indigenous peoples, and respects their laws, customs, and protocols associated with their spiritual and land rights.

Waasigan is within the traditional territories of the Treaty #3 and Robinson-Superior First Nations and traverses the Northwestern Ontario Métis Community and Northern Lake Superior Métis Community. Indigenous peoples practice their Treaty, Aboriginal and Inherent rights, including harvesting rights, on these lands. Hydro One understands that individual Indigenous communities are independent Nations and have expressed unique relationships, jurisdictions, responsibilities, and requirements as it pertains to land rights.

The Crown has a Duty to Consult, and where appropriate, accommodate Indigenous peoples whenever a Crown decision or activity could impact established or asserted Aboriginal and Treaty rights. The Ministry of Energy (formerly the Ministry of Energy, Northern Development and Mines) delegated the procedural aspects of the Crown's Duty to Consult to Hydro One via a letter dated October 25, 2018[3] and a follow-up letter dated April 15, 2020[4]. The Ministry of Energy determined Hydro One's proposed Project may have the potential to affect First Nation and Métis communities who hold or claim Aboriginal or Treaty Rights protected under Section 35 of Canada's Constitution Act,1982. Hydro One entered into a Crown Delegation MOU, which identifies Crown responsibilities, Hydro One responsibilities, record keeping and information sharing requirements, and an Indigenous Consultation Plan requirement. Hydro One worked with Indigenous Communities to develop a Consultation Plan which identified its commitments and activities for Indigenous engagement on the Project. Fundamental to the plan is the need for meaningful engagement and relationships with the individual

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[3] Exhibit E, Tab 1, Schedule 1, Attachment 11
[4] Exhibit E, Tab 1, Schedule a, Attachment 12

Indigenous communities, to understand and address any concerns over impacts to Section 35 rights, so that Indigenous peoples can share in the benefits from the Project.

With respect to non-Indigenous land rights, Phase 1 of the Project will require Hydro One to acquire land rights from approximately 164 directly impacted property owners, consisting of 156 privately held properties, 5 Crown properties, 1 municipally held property and 2 railway crossings. The majority of properties will require Hydro One to acquire easement or fee simple corridor takings, at the property owner's election. A small number of properties will have dwellings and or major outbuildings within the new Hydro One corridor. Hydro One will work with directly impacted property owners to negotiate amicable voluntary agreements, which may include full property buyouts, at the property owner's election.

Additionally, Phase 1 of the Project will require Hydro One to acquire consent from approximately 260 existing permit holders, consisting of 32 unique permit holders who have an interest in unpatented Crown Lands. The existing permits intersect the current proposed Project corridor, and the large majority are mining claims. Hydro One will work with the appropriate permit holders to obtain consent for the disposition of their surface rights along the current proposed project corridor.

Phase 2 of the Project will require Hydro One to acquire land rights from approximately 97 directly impacted property owners, consisting of 78 privately held properties, 1 federally held property, 7 Crown properties, 7 municipally held properties, 2 Ontario Power Generation properties and 2 railway crossings. Like Phase 1, Phase 2 of the Project will require Hydro One to acquire easement or fee simple corridors on the majority of properties, at the property owner's election. A small number of properties will have dwellings and/or major outbuildings within the new Hydro One corridor. Hydro One will work with directly impacted property owners to negotiate amicable voluntary agreements, which may in some circumstances include full property buyouts, at the property owner's election.

Additionally, Phase 2 of the Project will require Hydro One to acquire consent from approximately 238 existing permit holders, consisting of 31 unique permit holders who have an interest in unpatented Crown Lands. The existing permits intersect the current proposed Project corridor and the large majority are mining claims. Hydro One will work with the appropriate permit holders to obtain consent for the disposition of their surface rights along the current proposed project corridor.

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

Table 1 - Phase 1: Summary of Property Types and Sizes Required

Land Ownership Type	Area (Hectares)	Proportion of Route (%)
Crown Lands (unpatented)	591.5	69%
Private Lands	247.1	29%
Provincial Lands	14.5	2%
Municipal Lands	2.6	< 1%
Railway Lands	0.8	< 1%

Table 2 - Phase 2: Summary of Property Types and Sizes Required

Land Ownership Type	Area (Hectares)	Proportion of Route (%)
Crown Lands (unpatented)	601.5	67%
Private Lands	246.4	28%
Provincial Lands	28.9	3%
Municipal Lands	18.2	2%
Federal Lands	0.1	< 1%
Railway Lands	0.3	< 1%

3.0 DESCRIPTION OF NEW LAND RIGHTS REQUIRED

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

- Land Use Permits on unpatented Crown Lands (new land rights required);
- Easement or fee simple rights on private, municipally owned, provincially owned and federally owned properties (new land rights required);
- Rail crossing agreements (new land rights required); and
- Temporary access and/or construction rights on provincially owned, unpatented Crown and private properties for access roads, temporary work headquarters, laydown areas, and material storage facilities (new land rights required).

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

- Early Access Agreement;
- Option to Purchase a Limited Interest – Easement;
- Compensation and Incentive Agreement – Easement;
- Option to Purchase – Fee Simple;
- Compensation and Incentive Agreement – Fee Simple;
- Rail Crossing Agreement (provided by rail company at a later date);
- Encroachment Permit (provided by Ministry of Transportation at a later date);
- Agreement for Temporary Rights;
- Off Corridor Access; and
- Damage Claim Agreement/Waiver.

Where crossings of public roads and highways are contemplated and indicated in **Exhibit C, Tab 2, Schedule 1, Attachment 3**, Hydro One will rely on the land rights afforded by section 41 of the Electricity Act (where applicable). Hydro One will notify and work with impacted road authorities, including municipalities and ministries, and obtain all required permits and/or agreements, including where agreements are required for the placement of infrastructure per section 41(9) of the Electricity Act. All road crossings will be designed to meet or exceed CSA vertical clearance standards. Structures shall be located so that tower legs and guy wire anchor locations (above ground) are at least 20 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 for Phase 1, followed by Phase 2, or on an as needed basis.

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

4.0 EARLY ACCESS TO LAND

Hydro One requires early access to the corridor to perform various activities/studies associated with the Project which include specific environmental studies, engineering and design studies, and property specific land valuations/studies. In order to facilitate the required access to the properties affected by the corridor in advance of Leave to Construct approval, Hydro One has been and will continue to be entering into early access agreements with affected landowners. To date, Hydro One has achieved voluntary early access agreements on 79% of the properties affected by the corridor in Phase 1 of the Project.

Hydro One is in the early stages of engagement with directly impacted property owners on Phase 2 of the Project for early access rights. Engagement with these owners has recently been initiated based on the recent directive from the IESO regarding Phase 2 in-service expectations.

5.0 LAND ACQUISITION PROCESS

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

Hydro One's real estate representatives have been meeting with affected property owners on Phase 1 since January, 2023. Engagement with affected owners on Phase 2 has commenced in June 2023. The objective of initial meetings is to introduce Hydro One's voluntary land acquisition process. Independent site-specific property appraisals will be prepared for all impacted properties. For Phase 1, appraisal work commenced in March, 2023. Appraisal work for Phase 2 is expected to commence in fall 2023. Hydro One will prepare voluntary property settlement offers based on these appraisals and the Company's Land Acquisition Compensation Principles. Affected property owners will be advised that they have the option to receive independent legal advice and that Hydro One is committed to reimbursing affected property owners for reasonably incurred legal fees associated with the review and execution of the necessary land rights agreements.

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

All other applicable agreements (e.g. Land Use Permits, rail crossing agreements, temporary rights agreements, etc.) will be utilized as part of the land acquisition process as required. A summary of all land negotiations to date, including their status, is summarised below in Table 3 below:

Table 3 - Land Acquisition Status

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	Phase 1: 156 Phase 2: 78	97% Pending	79% Pending	Pending Pending	Pending Pending	- Routing - Construction and Access - Future Maintenance - Trespassing - Etc.	- Continue to negotiate - Accommodate minor route refinements where and to the extent possible
Federal	Phase 1: 0 Phase 2: 1	N/A Pending	N/A Pending	N/A Pending	N/A Pending	- None to date	- N/A
Crown	Phase 1: 5 Phase 2: 7	100% Pending	100% Pending	Pending Pending	Pending Pending	Proximity of structures to designated transportation expansion areas	Locate structures in undesignated locations where they are situated on Crown lands
Municipal	Phase 1: 1 Phase 2: 7	100% Pending	100% Pending	Pending Pending	Pending Pending	None to date	N/A
OPG	Phase 1: 0 Phase 2: 2	N/A Pending	N/A Pending	N/A Pending	N/A Pending	None to date	N/A
Railway	Phase 1: 2 Phase 2: 2	N/A N/A	N/A N/A	Pending Pending	Pending Pending	None to date	N/A

5.0 LAND-RELATED FORMS

Provided as **Attachments 1 through 9** of this Schedule are the land rights agreements that Hydro One intends to utilize in order to obtain the required new land rights for the Project and for related Project activities.

The tables below indicate prior Hydro One OEB s.92 proceedings that have approved these forms of agreements, and if, or how, they are like what was previously approved by the Board and whether each contain any substantive changes to previously approved forms for the same purpose.

Table 4 below indicates the proceeding in which the forms of these agreements have been approved. These forms remain unchanged.

Table 4 - Forms of Agreement Remaining Unchanged

Form of Agreement	Attachment in this Schedule	Previous OEB Docket
Agreement for Temporary Rights	2	EB-2022-0140 Exhibit E, Tab 1, Schedule 1, Attachment 2
Damage Claim Agreement/Waiver	3	EB-2022-0140 Exhibit E, Tab 1, Schedule 1, Attachment 3
Compensation and Incentive Agreement – Easement	5	EB-2022-0140 Exhibit E, Tab 1, Schedule 1, Attachment 5
Option to Purchase – Fee Simple	6	EB-2022-0140 Exhibit E, Tab 1, Schedule 1, Attachment 6
Compensation and Incentive Agreement – Fee Simple	7	EB-2022-0140 Exhibit E, Tab 1, Schedule 1, Attachment 7
Off Corridor Access	8	EB-2022-0140 Exhibit E, Tab 1, Schedule 1, Attachment 8

Table 5 below indicates the proceeding in which the form of these agreements have been approved and, where applicable, describes any specific change/s.

Table 5 - Forms of Agreement Remaining Materially Unchanged

Form of Agreement	Attachment in this Schedule	Previous OEB Docket	Change Description
Option to Purchase a Limited Interest – Easement	4	EB-2022-0140 Exhibit E, Tab 1, Schedule 1, Attachment 4	Clause 3 in Schedule "C" removed as it pertains specifically to agricultural lands which is **not** applicable for the route location of this Project (however, Hydro One will re-insert as necessary if any agricultural operations are found).
Option to Purchase a Limited Interest – Easement with a Voluntary Buyout Offer	9	EB-2022-0140 Exhibit E, Tab 1, Schedule 1, Attachment 10	Clause 3 in Schedule "C" removed as it pertains specifically to agricultural lands which is **not** applicable for the route location of this Project (however, Hydro One will re-insert as necessary if any agricultural operations are found).

Table 6 below includes the form of access agreement similar in nature to a form previously approved by the OEB, being within docket EB-2022-0140[5], however containing substantive changes prompting submission by Hydro One for approval as a 'new' standalone form.

Table 6 - Forms of Agreement that include Material Changes

Form of Agreement	Attachment in this Schedule
Early Access Agreement	1

[5] Specifically Exhibit E, Tab 1, Schedule 1, Attachment 1.

EARLY ACCESS AGREEMENT

THIS AGREEMENT made in duplicate the _________ day of ______________ 2023.

BETWEEN:

(INSERT NAME)

(the **"Owner"**)
OF THE FIRST PART

AND:

HYDRO ONE NETWORKS INC.

(**"HONI"**)
OF THE SECOND PART

WHEREAS the Owner is the registered owner of lands legally described as ***(INSERT LEGAL DESCRIPTION),* being PIN *(INSERT PIN)* (the "Lands")**

AND WHEREAS the Owner is agreeable in allowing HONI to enter onto a portion of the Lands highlighted in yellow as shown on the sketch attached hereto as Schedule "A" (the "Strip"), in order to commence pre-construction activities in conjunction with the Waasigan Transmission Line Project (the "Project"), which shall include but are not limited to soil studies, environmental studies, engineering studies, property appraisals and surveys in, on or below the Strip subject to the terms and conditions contained herein (collectively the "Activities").

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of Two Dollars ($2.00) 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 Owner hereby grants to HONI and its respective officers, employees, workers, permittees, agents, surveyors, contractors and subcontractors, with or without vehicles, supplies, machinery, plant, material and equipment, (i) the right to commence the Activities on the Strip; and (ii) the right to enter upon and exit from, and to pass and repass at any and all times in, over, along, upon, across, and through the Strip and so much of the Lands as may be reasonably necessary.

2. The permission granted herein shall commence as of the date this Agreement (the "Commencement Date") and shall terminate three (3) years from the Commencement Date (the "Initial Term").

3. The Initial Term may be extended upon five (5) days prior notice from HONI to the Owner for an additional two (2) years on the same terms and conditions contained herein save for this right to extend (the "Extended Term").

4. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Lands shall be at the sole risk of HONI and the Owner 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 Owner.

5. Upon execution of this Agreement by all parties, HONI shall pay to the Owner the amount of **TWO THOUSAND FIVE HUNDRED Dollars ($2,500.00)** plus Harmonized Sales Tax ("HST") if applicable, which is compensation for the permission granted herein for the Initial Term.

6. In the event that HONI exercises its right to extend the Initial Term, HONI shall pay to the Owner the amount of ONE THOUSAND Dollars ($1,000.00), which is compensation for the permission granted herein for the Extended Term.

7. HONI shall repair any physical damage to the Lands resulting from the Activities and, shall restore the Lands to their original condition so far as possible and practicable to the satisfaction of the Owner, acting reasonably.

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

9. This Agreement does not commit the Owner to enter into any further agreements with HONI in conjunction with the Project.

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

11. This Agreement may be executed in one or more counterparts and delivered by electronic means, each of which shall be deemed an original and all of which when, taken together, shall constitute one and the same Agreement.

IN WITNESS WHEREOF the Parties have hereunto set their respective hands and seals to this Agreement.

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

)
)
)
)
)
______________________________) ____________________________ (seal)
Print Name of Witness ***Owner Name***

IF GRANTOR IS CORPORATION – USE THE FOLLOWING

OWNER NAME

Per: ____________________________
Print Name:
Print Title:

Per: ____________________________
Print Name:
Print Title:

We/I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

Per: ____________________________
Print Name:
Title:

I have authority to bind the Corporation

SCHEDULE “A”

PROPERTY SKETCH

Conceptual sketch only.

AGREEMENT FOR TEMPORARY RIGHTS

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

Between:

[INSERT SUBJECT PROPERTY LEGAL OWNER]

(hereinafter referred to as the "Grantor")

OF THE FIRST PART

--- and ---

HYDRO ONE NETWORKS INC.

(hereinafter referred to "HONI")

OF THE SECOND PART

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

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

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

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

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

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

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

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

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

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

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

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

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

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

TO HONI:

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

Attention:
Tel:

TO GRANTOR:

XXXXXXX
XXXXXXX
XXXXXXX

Attention:
Tel:

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

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

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

[INSERT SUBJECT PROPERTY LEGAL OWNER]

____
Grantor's HST Registration Number

____
Name:
Title:

I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

____
Name:
Title:

I have authority to bind the Corporation

SCHEDULE "A"

*Sketch for reference only, not to scale.

DAMAGE CLAIM AGREEMENT/WAIVER

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

Between:

[INSERT NAME OF OWNER]

herein called the "**Claimant**"

- and-

Hydro One Networks Inc.

herein called the "**Hydro One**"

Witnesseth:

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

[INSERT DESCRIPTION OF DAMAGE]

Area

TOTAL $

.

Subject to Approval by Hydro One Networks Inc.

Witness

____

Signature

____

Signature

OPTION TO PURCHASE A LIMITED INTEREST – EASEMENT

OPTION AGREEMENT - EASEMENT

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

B E T W E E N:

«OWNER_1_NAME_FOR_LETTERS» & «OWNER_2_NAME_FOR_LETTERS» & «OWNER_3_NAME_FOR_LETTERS»

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

OF THE FIRST PART

- and -

HYDRO ONE NETWORKS INC.

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

OF THE SECOND PART

- and -

SPOUSE NAME

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

OF THE THIRD PART

RECITALS:

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

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

C. Hydro One has entered into an agreement with the Owner having a date the same as this Option Agreement (the "**Compensation and Incentive Agreement**") whereby Hydro One has offered to compensate the Owner for injurious affection damages in accordance with the terms and conditions contained therein.

NOW THEREFORE, the parties hereby agree as follows:

1. **GRANT OF OPTION**

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

2. **PURCHASE PRICE**

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

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

WITNESS:	**OWNER:**
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_1_name_for_letters»**
Address: 1800 Main Street East Milton, ON L9T 7S3	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_2_name_for_letters»**
Address: 1800 Main Street East Milton, ON L9T 7S3	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_3_name_for_letters»**
Address: 1800 Main Street East Milton, ON L9T 7S3	

WITNESS:	The spouse of the Owner hereby consents to this Agreement **SPOUSE OF OWNER:**
	l/s
Name: Real Estate Representative	Name: **Property Owner Spouse Name**
Address: 1800 Main Street East Milton, ON L9T 7S3	

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________________

Name:

Title:

I have authority to bind the Corporation

SCHEDULE “A”
LEGAL DESCRIPTION

«LEGAL_DESCRIPTION»

SCHEDULE "A-1"
EASEMENT LANDS

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

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

Screenshot of ortho map with tower placements here

SCHEDULE "B"
STANDARD TERMS AND CONDITIONS

1. EXERCISE OF OPTION

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

2. EXTENSION OF OPTION TERM

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

3. PURCHASE PRICE

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

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

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

4. CLOSING

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

5. ACKNOWLEDGEMENT AND DIRECTION

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

6. REGISTRATION OF EASEMENT

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

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

7. **RIGHT TO TRANSFER**

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

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

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

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

9. **SURVEY/REFERENCE PLAN**

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

10. **INCOME TAX ACT**

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

11. **HARMONIZED SALES TAX**

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

12. **NOTICE OF OPTION**

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

13. **NO OTHER RIGHTS**

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

14. **PRIOR ENCUMBRANCES**

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

15. **<u>TIME OF ESSENCE</u>**

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

16. **<u>NOTICES</u>**

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

HYDRO ONE:

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

185 Clegg Road
Markham, Ontario L3G 1B7

Attention:
Fax: (905) 946-6242

with a copy to its solicitors,

Barriston LLP
90 Mulcaster Street
Barrie, ON L4M 4Y5

Attention: Jim McIntosh
Fax: 705-721-4025

OWNER:

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

«SAP_Phone_Number»
«SAP_email_address»

with a copy to their solicitors,

Solicitors Name
Solicitors Address 1
Solicitors Address 2
Solicitors Address 3

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

17. **<u>ASSIGNMENT OF OPTION BY HYDRO ONE</u>**

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

18. **SURVIVAL OF REPRESENTATIONS**

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

19. **ENTIRE AGREEMENT**

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

20. **SEVERABILITY**

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

21. **GOVERNING LAW**

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

22. **SUCCESSORS AND ASSIGNS**

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

23. **EXECUTION AND DELIVERY**

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

24. **PLANNING ACT**

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

25. **FURTHER ASSURANCES**

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

26. **SPOUSAL CONSENT**

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

27. **AGE**

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

SCHEDULE "C"
TRANSFER AND GRANT OF EASEMENT

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

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

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

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

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

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

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

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

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

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

2. The Transferor agrees that:

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

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

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

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

(e) The Rights hereby granted:

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

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

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

4. 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.

5. 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.

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

SCHEDULE "D"
ACKNOWLEDGEMENT AND DIRECTION

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

This will confirm that:

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

Dated _________________, 20__.

WITNESS:	**OWNER:**
______________________________	______________________________ l/s
Name: «Real_Estate_Representative» Address: 1800 Main Street East Milton, ON L9T 7S3	Name: **«Owner_1_name_for_letters»**
______________________________	______________________________ l/s
Name: «Real_Estate_Representative» Address: 1800 Main Street East Milton, ON L9T 7S3	Name: **«Owner_2_name_for_letters»** ______________________________
______________________________	______________________________ l/s
Name: «Real_Estate_Representative» Address: 1800 Main Street East Milton, ON L9T 7S3	Name: **«Owner_3_name_for_letters»**

WITNESS:	The spouse of the Owner hereby consents to this Acknowledgement and Direction
	SPOUSE OF OWNER:
	l/s
Name: Real Estate Representative Address: 1800 Main Street East Milton, ON L9T 7S3	Name: **Property Owner Spouse Name**

«OWNER_1_NAME_FOR_LETTERS»

Per: ______________________

Name:

Title:

We/I have authority to bind the Corporation

COMPENSATION AND INCENTIVE AGREEMENT – EASEMENT

COMPENSATION AND INCENTIVE AGREEMENT - EASEMENT

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

B E T W E E N:

«OWNER_1_NAME_FOR_LETTERS» & «OWNER_2_NAME_FOR_LETTERS» & «OWNER_3_NAME_FOR_LETTERS»

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

OF THE FIRST PART

- and -

HYDRO ONE NETWORKS INC.

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

OF THE SECOND PART

- and -

SPOUSE NAME

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

OF THE THIRD PART

RECITALS:

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

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

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

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

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

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

NOW THEREFORE, the parties agree as follows:

1. VALUATION

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

(b) In recognition of a dynamic real estate market and that the effective date of HONI's appraised values in the HONI Appraisal are only relevant for a limited period of time, Hydro One shall provide a market value top-up where the passage of time between the effective date of the HONI Appraisal and the date Hydro One receives project approval pursuant to section 92 of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B. (the "Section 92 Approval") warrants such top-up (the "Top-Up").

Provided that the Owner and Hydro One have entered into an Option Agreement prior to Hydro One receiving the Section 92 Approval, the Owner shall be entitled to the Top-Up, if applicable. The amount of the Top-Up is the difference between the HONI Appraisal, and the market value as of the date of the Section 92 Approval (if such market value is greater than the amount in the HONI Appraisal), adjusted for time only (change in market conditions) and based on an independent land rate study considering this singular factor. The land rate study will be prepared by an independent third party appraiser with an Accredited Appraiser Canadian Institute designation from the Appraisal Institute of Canada.

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

(c) The actual area of the Easement Lands will be confirmed by a survey to be prepared by Hydro One and in the event the surveyed area of the Easement Lands is greater than as provided for in the Calculation Sheet, the payments set out in section 1 herein will be adjusted accordingly.

2. INCENTIVE PAYMENTS

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

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

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

3. WAIVER

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

4. IA COMPENSATION

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

5. CONVEYANCING

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

6. TENANTS

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

7. NOTICES

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

HYDRO ONE:

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

185 Clegg Road
Markham, Ontario L3G 1B7

Attention:
Fax: (905) 946-6242

with a copy to its solicitors,

Barriston LLP
90 Mulcaster Street
Barrie, ON L4M 4Y5

Attention: Jim McIntosh
Fax: 705-721-4025

OWNER:

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

«SAP_Phone_Number»
«SAP_email_address»

with a copy to their solicitors,

Solicitors Name
Solicitors Address 1
Solicitors Address 2
Solicitors Address 3

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

8. ASSIGNMENT OF AGREEMENT BY OWNER

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

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

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

9. NOTICE OF AGREEMENT

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

10. NO MERGER

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

11. ENTIRE AGREEMENT

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

12. SEVERABILITY

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

13. GOVERNING LAW

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

14. SPOUSAL CONSENT

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

15. SUCCESSORS AND ASSIGNS

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

16. EXECUTION AND DELIVERY

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

17. FURTHER ASSURANCES

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

18. AGE

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

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

WITNESS:

Name: «Real_Estate_Representative»

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

Name: «Real_Estate_Representative»

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

Name: «Real_Estate_Representative»

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

OWNER:

l/s

Name: **«Owner_1_name_for_letters»**

l/s

Name: **«Owner_2_name_for_letters»**

l/s

Name: **«Owner_3_name_for_letters»**

WITNESS:

Name: «Real_Estate_Representative»

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

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

SPOUSE OF OWNER:

l/s

Name: **Property Owner Spouse Name**

HYDRO ONE
HST 870865821RT0001

HYDRO ONE NETWORKS INC.

Per:

Name:

Title:

I have authority to bind the Corporation

SCHEDULE “A”

LANDS

«LEGAL_DESCRIPTION»

SCHEDULE “B”

CALCULATION SHEET

OPTION TO PURCHASE – FEE SIMPLE

OPTION AGREEMENT - FEE SIMPLE CORRIDOR

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

B E T W E E N:

«OWNER_1_NAME_FOR_LETTERS» & «OWNER_2_NAME_FOR_LETTERS» & «OWNER_3_NAME_FOR_LETTERS»

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

OF THE FIRST PART

- and -

HYDRO ONE NETWORKS INC.

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

OF THE SECOND PART

- and -

SPOUSE NAME

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

OF THE THIRD PART

RECITALS:

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

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

C. Hydro One has entered into an agreement with the Owner having a date the same as this Option Agreement (the "Compensation and Incentive Agreement") whereby Hydro One has offered to compensate the Owner for injurious affection damages in accordance with the terms and conditions contained therein.

NOW THEREFORE, the parties hereby agree as follows:

1. **GRANT OF OPTION**

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

2. **PURCHASE PRICE**

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

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

WITNESS:

OWNER:

l/s

Name: «Real_Estate_Representative»

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

Name: **«Owner_1_name_for_letters»**

l/s

Name: «Real_Estate_Representative»

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

Name: **«Owner_2_name_for_letters»**

l/s

Name: «Real_Estate_Representative»

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

Name: **«Owner_3_name_for_letters»**

WITNESS:

The spouse of the Owner hereby consents to this Agreement

SPOUSE OF OWNER:

l/s

Name: Real Estate Representative

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

Name: **Property Owner Spouse Name**

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________

Name:
Title:

I have authority to bind the Corporation

File: «FileNo»

SCHEDULE "A"
LEGAL DESCRIPTION

«LEGAL_DESCRIPTION»

File: «FileNo»

SCHEDULE "A-1"
CORRIDOR LANDS

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

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

Screenshot of ortho map with tower placements here

SCHEDULE "B"
STANDARD TERMS AND CONDITIONS

1. EXERCISE OF OPTION

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

2. EXTENSION OF OPTION TERM

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

3. PURCHASE PRICE

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

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

4. CLOSING

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

5. AGREEMENT OF PURCHASE AND SALE

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

6. RIGHT TO TRANSFER AND TITLE

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

7. INSPECTION PERIOD AND EARLY ACCESS PERIOD

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

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

8. SURVEY/REFERENCE PLAN

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

9. INCOME TAX ACT

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

10. HARMONIZED SALES TAX

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

11. NOTICE OF OPTION

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

12. NO OTHER RIGHTS

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

13. PRIOR ENCUMBRANCES

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

14. TIME OF ESSENCE

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

15. NOTICES

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

HYDRO ONE:

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

185 Clegg Road
Markham, Ontario
L3G 1B7

Attention:
Fax: (905) 946-6242

with a copy to its solicitors,

Barriston LLP
90 Mulcaster Street
Barrie, ON L4M 4Y5

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

OWNER:

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

«SAP_Phone_Number»
«SAP_email_address»

with a copy to their solicitors,

Solicitors Name
Solicitors Address 1
Solicitors Address 2
Solicitors Address 3

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

16. ASSIGNMENT OF OPTION BY HYDRO ONE

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

17. SURVIVAL OF REPRESENTATIONS

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

18. ENTIRE AGREEMENT

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

19. SEVERABILITY

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

20. GOVERNING LAW

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

21. SUCCESSORS AND ASSIGNS

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

22. EXECUTION AND DELIVERY

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

23. PLANNING ACT

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

24. FURTHER ASSURANCES

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

25. SPOUSAL CONSENT

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

26. AGE

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

SCHEDULE "C"
AGREEMENT OF PURCHASE AND SALE

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

B E T W E E N:

«OWNER_1_NAME_FOR_LETTERS» & «OWNER_2_NAME_FOR_LETTERS» & «OWNER_3_NAME_FOR_LETTERS»

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

OF THE FIRST PART

- and -

HYDRO ONE NETWORKS INC.

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

OF THE SECOND PART

- and -

SPOUSE NAME

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

OF THE THIRD PART

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

ARTICLE 1
OFFER

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

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

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

NIL

ARTICLE 2
PURCHASE PRICE

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

(b) The Total Compensation is comprised as follows:

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

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

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

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

ARTICLE 3
CLOSING

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

3.2 On Closing,

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

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

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

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

ARTICLE 4
INSPECTION PERIOD

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

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

ARTICLE 5
TITLE

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

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

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

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

ARTICLE 6
PURCHASER'S INVESTIGATION RESULTS

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

ARTICLE 7
INSURANCE

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

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

ARTICLE 8
PLANNING ACT

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

ARTICLE 9
ADDITIONAL PROVISIONS

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

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

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

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

HYDRO ONE:

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

185 Clegg Road
Markham, Ontario L3G 1B7

Attention:
Fax: (905) 946-6242

with a copy to its solicitors,

Barriston LLP
90 Mulcaster St
Barrie, ON L4M 4Y5

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

OWNER:

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

«SAP_Phone_Number»
«SAP_email_address»

with a copy to their solicitors,

Solicitors Name
Solicitors Address 1
Solicitors Address 2
Solicitors Address 3

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

WITNESS:

OWNER:

l/s

Name: «Real_Estate_Representative»

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

Name: **«Owner_1_name_for_letters»**

l/s

Name: «Real_Estate_Representative»

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

Name: **«Owner_2_name_for_letters»**

l/s

Name: «Real_Estate_Representative»

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

Name: **«Owner_3_name_for_letters»**

WITNESS:

The spouse of the Owner hereby consents to this Agreement

SPOUSE OF OWNER:

l/s

Name: Real Estate Representative

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

Name: **Property Owner Spouse Name**

HYDRO ONE NETWORKS INC.

Per:

Name:
Title:

I have authority to bind the Corporation

HYDRO ONE
HST 870865821RT0001

SCHEDULE “A”
LEGAL DESCRIPTION OF LANDS

«LEGAL_DESCRIPTION

SCHEDULE "A-1"
LEGAL DESCRIPTION OF PROPERTY

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

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

Screenshot of ortho map with tower placements here

SCHEDULE "B"

PERMITTED ENCUMBRANCES

NIL

SCHEDULE "C"

CALCULATION SHEET

COMPENSATION AND INCENTIVE AGREEMENT – FEE SIMPLE

COMPENSATION AND INCENTIVE AGREEMENT – FEE SIMPLE

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

B E T W E E N:

«OWNER_1_NAME_FOR_LETTERS» & «OWNER_2_NAME_FOR_LETTERS» & «OWNER_3_NAME_FOR_LETTERS»

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

OF THE FIRST PART

- and -

HYDRO ONE NETWORKS INC.

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

OF THE SECOND PART

- and -

SPOUSE NAME

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

OF THE THIRD PART

RECITALS:

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

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

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

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

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

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

NOW THEREFORE, the parties agree as follows:

1. **VALUATION**

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

(b) In recognition of a dynamic real estate market and that the effective date of HONI's appraised values in the HONI Appraisal are only relevant for a limited period of time, Hydro One shall provide a market value top-up where the passage of time between the effective date of the HONI Appraisal and the date Hydro One receives project approval pursuant to section 92 of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B. (the "Section 92 Approval") warrants such top-up (the "Top-Up").

Provided that the Owner and Hydro One have entered into an Option Agreement prior to Hydro One receiving the Section 92 Approval, the Owner shall be entitled to the Top-Up, if applicable. The amount of the Top-Up is the difference between the HONI Appraisal, and the market value as of the date of the Section 92 Approval (if such market value is greater than the amount in the HONI Appraisal), adjusted for time only (change in market conditions) and based on an independent land rate study considering this singular factor. The land rate study will be prepared by an independent third party appraiser with an Accredited Appraiser Canadian Institute designation from the Appraisal Institute of Canada.

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

2. **INCENTIVE PAYMENTS**

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

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

(c) On the Closing Date, Hydro One shall make a further incentive payment to or to the order of the Owner in the amount of **XXXXX ($XX), (the "Premium Above Fair Market Value")** such amount being equal to 25% of the appraised fair market value of the Owner's fee simple interest in the Corridor Lands as set out on the Calculation Sheet.

3. **WAIVER**

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

4. **IA COMPENSATION**

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

5. **CONVEYANCING**

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

6. **TENANTS**

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

7. **NOTICES**

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

HYDRO ONE:

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

185 Clegg Road
Markham, Ontario L3G 1B7

Attention:
Fax: (905) 946-6242

with a copy to its solicitors,

Barriston LLP
90 Mulcaster Street
Barrie, ON L4M 4Y5

Attention: Jim McIntosh
Fax: 705-721-4025

OWNER:

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

«SAP_Phone_Number»
«SAP_email_address»

with a copy to their solicitors,

Solicitors Name
Solicitors Address 1
Solicitors Address 2
Solicitors Address 3

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

8. **ASSIGNMENT OF AGREEMENT BY OWNER**

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

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

9. NOTICE OF AGREEMENT

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

10. NO MERGER

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

11. ENTIRE AGREEMENT

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

12. SEVERABILITY

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

13. GOVERNING LAW

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

14. SPOUSAL CONSENT

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

15. SUCCESSORS AND ASSIGNS

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

16. EXECUTION AND DELIVERY

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

17. FURTHER ASSURANCES

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

18. AGE

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

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

WITNESS:	**OWNER:**
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_1_name_for_letters»**
Address: 1800 Main Street East Milton, ON L9T 7S3	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_2_name_for_letters»**
Address: 1800 Main Street East Milton, ON L9T 7S3	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_3_name_for_letters»**
Address: 1800 Main Street East Milton, ON L9T 7S3	
WITNESS:	The spouse of the Owner hereby consents to this Compensation and Incentive Agreement
	SPOUSE OF OWNER:
	l/s
Name: «Real_Estate_Representative»	Name: **Property Owner Spouse Name**
Address: 1800 Main Street East Milton, ON L9T 7S3	

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________
Name:
Title:

I have authority to bind the Corporation

SCHEDULE "A"

LANDS

«LEGAL_DESCRIPTION»

SCHEDULE “B”

CALCULATION SHEET

OFF CORRIDOR ACCESS

THIS AGREEMENT made in duplicate the ___________day of ___________ __2021

Between:

XXXXXXXXX

(hereinafter referred to as the "Grantor")

OF THE FIRST PART

--- and ---

HYDRO ONE NETWORKS INC.

(hereinafter referred to as "HONI")

OF THE SECOND PART

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

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

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

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

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

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

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

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

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

6. HONI agrees that it shall indemnify and save harmless the Grantor from and against all claims, demands, costs, damages, expenses and liabilities (collectively the "Costs") whatsoever arising out of HONI's presence on the Off-Corridor Access Lands or of its activities on or in connection with the Off-Corridor Access Lands arising out of the

permission granted herein except to the extent any of such Costs arise out of or are contributed to by the negligence or willful misconduct by the Grantor.

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

TO HONI:

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

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

TO GRANTOR:

XXXXXXXX
XXXXXXXX

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

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

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

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

HYDRO ONE
HST # 870 865 821 RT001

HYDRO ONE NETWORKS INC.

By: ____________________

Name:

Title:

I have authority to bind the Corporation

SCHEDULE "A"

PROPERTY SKETCH

OPTION TO PURCHASE A LIMITED INTEREST – EASEMENT WITH A VOLUNTARY BUYOUT OFFER

OPTION AGREEMENT - EASEMENT

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

B E T W E E N:

«OWNER_1_NAME_FOR_LETTERS» & «OWNER_2_NAME_FOR_LETTERS» & «OWNER_3_NAME_FOR_LETTERS»

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

OF THE FIRST PART

- and -

HYDRO ONE NETWORKS INC.

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

OF THE SECOND PART

- and -

SPOUSE NAME

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

OF THE THIRD PART

RECITALS:

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

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

C. Hydro One has entered into an agreement with the Owner having a date the same as this Option Agreement (the "**Compensation and Incentive Agreement**") whereby Hydro One has offered to compensate the Owner for injurious affection damages in accordance with the terms and conditions contained therein.

D. As the Owner's primary residence is located on the Lands within 100 metres from the centreline of the proposed new transmission line to be constructed on the Easement Lands, Hydro One has agreed that if Hydro One exercises the Option it will offer to purchase the Lands up to December 31, 2026 on the terms and conditions of the Voluntary Buyout Offer (the "Voluntary Buyout Offer") attached as Schedule "E" to this Option Agreement which Voluntary Buyout Offer shall be made on the Closing Date.

NOW THEREFORE, the parties hereby agree as follows:

1. **GRANT OF OPTION**

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

2. **PURCHASE PRICE**

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

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

WITNESS:	**OWNER:**
	l/s
Name: «Real_Estate_Representative» Address: 1800 Main Street East Milton, ON L9T 7S3	Name: **«Owner_1_name_for_letters»**
	l/s
Name: «Real_Estate_Representative» Address: 1800 Main Street East Milton, ON L9T 7S3	Name: **«Owner_2_name_for_letters»**
	l/s
Name: «Real_Estate_Representative» Address: 1800 Main Street East Milton, ON L9T 7S3	Name: **«Owner_3_name_for_letters»**
WITNESS:	The spouse of the Owner hereby consents to this Agreement **SPOUSE OF OWNER:**
	l/s
Name: «Real_Estate_Representative» Address: 1800 Main Street East Milton, ON L9T 7S3	Name: **Property Owner Spouse Name**

«OWNER_1_NAME_FOR_LETTERS»

Per: ______________________________

Name:

Title:

We/I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________________

Name: Aaron Fair

Title: Real Estate Services Supervisor

I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________________

Name: Ranjit Multani

Title: Manager, Facilities & Real Estate Acquisition

I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________________

Name: Erin Kelly

Title: Director, Facilities & Real Estate

I have authority to bind the Corporation

SCHEDULE "A"
LEGAL DESCRIPTION

«LEGAL_DESCRIPTION»

SCHEDULE "A-1"
EASEMENT LANDS

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

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

Screenshot of ortho map with tower placements here

SCHEDULE "B"
STANDARD TERMS AND CONDITIONS

1. **EXERCISE OF OPTION**

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

2. **EXTENSION OF OPTION TERM**

At any time during the Option Term, Hydro One may, by written notice delivered to the Owner prior to the expiration of the Option Term, as same may have been extended, extend the Option Term with respect to the Lands for one (1) additional period of one (1) year, provided that upon such election, Hydro One pays to the Owner the amount of $10,000 in consideration for the extension of the Option Term.

3. **PURCHASE PRICE**

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

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

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

4. **CLOSING**

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

5. **ACKNOWLEDGEMENT AND DIRECTION**

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

6. **REGISTRATION OF EASEMENT**

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

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

7. **RIGHT TO TRANSFER**

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

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

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

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

9. **SURVEY/REFERENCE PLAN**

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

10. **INCOME TAX ACT**

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

11. **HARMONIZED SALES TAX**

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

12. **NOTICE OF OPTION**

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

13. **NO OTHER RIGHTS**

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

14. **PRIOR ENCUMBRANCES**

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

15. **TIME OF ESSENCE**

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

16. **NOTICES**

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

HYDRO ONE:

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

185 Clegg Road
Markham, Ontario L3G 1B7

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

with a copy to its solicitors,

Barriston LLP
90 Mulcaster Street
Barrie, ON L4M 4Y5

Attention: Jim McIntosh
Fax: 705-721-4025

OWNER:

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

«SAP_Phone_Number»
«SAP_email_address»

with a copy to their solicitors,

Solicitors Name
Solicitors Address 1
Solicitors Address 2
Solicitors Address 3

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

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

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

18. **SURVIVAL OF REPRESENTATIONS**

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

19. **ENTIRE AGREEMENT**

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

20. **SEVERABILITY**

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

21. **GOVERNING LAW**

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

22. **SUCCESSORS AND ASSIGNS**

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

23. **EXECUTION AND DELIVERY**

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

24. **PLANNING ACT**

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

25. **FURTHER ASSURANCES**

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

26. **SPOUSAL CONSENT**

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

27. **AGE**

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

28. **VOLUNTARY BUYOUT OFFER**

a) If Hydro One exercises the Option in accordance with the terms hereof then, on Closing in addition to delivery of a cheque for the Purchase Price, Hydro One shall deliver to the Owner an offer to purchase the Lands on the terms set out in the Voluntary Buyout Offer attached as Schedule "E".

b) The Purchase Price of the Voluntary Buyout Offer shall be the fair market value of the Lands as determined by a new appraisal commissioned by Hydro One and, prepared by an external, independent appraiser with the Accredited Appraiser Canadian Institute ("AACI") designation at the time the Owner accepts the offer set out in Schedule "E" of this Option Agreement.

If the Owner does not accept the Voluntary Buyout Offer within the prescribed time specified therein, Hydro One shall not be required to purchase the Owner's interest in the Lands, and the Voluntary Buyout Offer shall be of no further force or effect and Hydro One shall be released of all obligations in respect thereof.

SCHEDULE "C"
TRANSFER AND GRANT OF EASEMENT

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

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

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

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

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

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

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

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

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

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

2. The Transferor agrees that:

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

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

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

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

(e) The Rights hereby granted:

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

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

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

4. 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.

5. 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.

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

SCHEDULE "D"
ACKNOWLEDGEMENT AND DIRECTION

TO: Hydro One Networks Inc. ("**Hydro One**") and its solicitors, Barriston LLP

AND TO: Any and all designees of the above

RE: Option Agreement dated __________________, 20____, (the "Option Agreement) and the Transfer and Grant of Easement in substantially the form attached **[as Schedule "C" to the Option Agreement or hereto]** (the "Easement Agreement")

This will confirm that:

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

Dated _________________, 20__.

WITNESS:	**OWNER:**
______________________________	______________________________ l/s
Name: «Real_Estate_Representative»	Name: **«Owner_1_name_for_letters»**
Address: 1800 Main Street East Milton, ON L9T 7S3	
______________________________	______________________________ l/s
Name: «Real_Estate_Representative»	Name: **«Owner_2_name_for_letters»**
Address: 1800 Main Street East Milton, ON L9T 7S3	______________________________
______________________________	

l/s

Name: «Real_Estate_Representative»

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

Name: **«Owner_3_name_for_letters»**

WITNESS:

Name: «Real_Estate_Representative»

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

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

SPOUSE OF OWNER:

l/s

Name: **Property Owner Spouse Name**

«OWNER_1_NAME_FOR_LETTERS»

Per: ______________________

Name:
Title:

We/I have authority to bind the Corporation

SCHEDULE "E"
VOLUNTARY BUYOUT OFFER

B E T W E E N:

«OWNER_1_NAME_FOR_LETTERS» & «OWNER_2_NAME_FOR_LETTERS» & «OWNER_3_NAME_FOR_LETTERS»

(hereinafter called the "**Vendor**")

OF THE FIRST PART

- and -

HYDRO ONE NETWORKS INC.

(hereinafter called the "Purchaser")

OF THE SECOND PART

- and -

XXXXXXXX

(hereinafter called the "**Spouse**")

OF THE THIRD PART

RECITALS

A. The Vendor entered into an Option Agreement with the Purchaser dated ● (the "**Option Agreement**") pursuant to which the Vendor granted the Purchaser an option to purchase a right-of-way and easement (the "**Easement**") in, on, over, under, across and through that portion of the Lands described on Schedule "A-1" attached thereto (the "**Easement Lands**"), the terms of which are more particularly set out in the Transfer and Grant of Easement (the "**Easement Agreement**") attached thereto as Schedule "C".

B. The Purchaser entered into an agreement with the Vendor having a date the same as the Option Agreement (the "**Compensation and Incentive Agreement**") whereby the Purchaser offered to compensate the Vendor for injurious affection damages, if applicable.

C. The Purchaser has exercised the Option to acquire the Easement pursuant to the Option Agreement.

D. As the Vendor's primary residence is located on the Lands within 100 metres from the centreline of the proposed new transmission line to be constructed on the Easement Lands, pursuant to the Option Agreement the Purchaser agreed to offer to purchase the Lands on the terms and conditions set out herein.

E. Initially capitalized terms not otherwise defined in this agreement shall have the meaning given to them in the Option Agreement and Compensation and Incentive Agreement.

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

ARTICLE 1
OFFER

1.1 The Purchaser hereby offers to purchase from the Vendor the lands and premises more particularly described in Schedule "A" attached hereto (the "**Lands**") upon and subject to the terms and conditions hereinafter set forth.

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

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

To be determined

1.4 The parties acknowledge and agree that this offer shall be irrevocable by the Purchaser until 3:30PM on the earlier of:

(a) December 31, 2026; or

(b) the date on which the Vendor ceases to be the registered and beneficial owner of the Lands (the "Irrevocable Date").

If the Vendor has not delivered a copy of this Agreement executed by the Vendor to the Purchaser on or before 3:30PM on the Irrevocable Date, this offer shall be null and void.

ARTICLE 2
PURCHASE PRICE

2.1 The purchase price for the Lands (the "Purchase Price") shall be the fair market value of the Lands as determined, as of the date of acceptance of this offer by the Vendor, by an external, independent AACI accredited appraiser retained by the Purchaser, at its expense, less an amount equal to the aggregate of the following amounts paid by the Purchaser to the Vendor pursuant to the Option Agreement and the Compensation and Incentive Agreement:

(a) the Purchase Price for the Easement (as defined in the Option Agreement) in the amount of XXXXX Dollars ($XXXXX.00);
(b) the IA Compensation, if any, in the amount of XXXXX Dollars ($XXXXX.00);
(c) Other compensation, if any, in the amount of XXXXX Dollars ($XXXXX.00).

2.2 The amount to be paid by the Purchaser to the Vendor on Closing for the Lands shall be the Purchase Price, as adjusted, after deducting the amounts as set out in Section 2.1 hereof, being the minimum amount of XXXXX Dollars ($XXXXX.00) representing the current fair market value of the land after adjustments. Should the appraised value of the land at the time of acceptance by the Vendor yield a result after adjustments that exceeds the minimum, the Vendor shall be entitled to the excess value. Should the appraised value of the land at the time of acceptance by the Vendor yield a result after adjustments that is less than the minimum, the Vendor shall be entitled to the minimum.

2.3 The Purchaser agrees to obtain and register, at its sole expense, any new Reference Plan with respect to the Lands that may be required by the Purchaser for completion of the transaction contemplated herein.

ARTICLE 3
CLOSING

3.1 The closing of this transaction shall be completed on the day that is ninety (90) days after the Vendor notifies the Purchaser of its intention to accept the Offer. If the Closing falls on a day when the Land Registry Office (the "Land Registry Office") in which the Lands are registered is closed, then the Closing shall be extended to the next day on which the Land Registry Office is open. 3.2 On Closing:

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

(b) The Purchaser shall pay to the Vendor by uncertified cheque or electronic funds transfer the Purchase Price as adjusted and subject to the deductions made in accordance with section 2.1 of this Agreement;

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

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

3.3 In the event that there is a delay in the completion of the transaction beyond the Closing Date as established by Hydro One upon delivery of the Exercise Notice that arises through no fault of Hydro One, then Hydro One shall not be responsible for any resulting delay in the Closing Date.

ARTICLE 4
TITLE

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

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

4.3 The Vendor agrees to provide to the Purchaser any existing survey of the Lands in the Vendor's possession, within fifteen (15) days from the date of the Vendor's acceptance of the offer.

ARTICLE 5
PURCHASER'S INVESTIGATION RESULTS

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

ARTICLE 6
INSURANCE

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

6.2 Pending completion, Vendor shall hold all insurance policies and the proceeds thereof in trust for the parties as their interests may appear and in the event of substantial damage to the Lands the Purchaser will take the proceeds of any insurance and complete the purchase.

ARTICLE 7
PLANNING ACT

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

ARTICLE 8
ADDITIONAL PROVISIONS

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

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

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

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

HYDRO ONE:

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

185 Clegg Road
Markham, Ontario L3G 1B7

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

with a copy to its solicitors,

Barriston LLP
90 Mulcaster St
Barrie, ON L4M 4Y5

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

OWNER:

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

«SAP_Phone_Number»
«SAP_email_address»

with a copy to their solicitors,

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

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

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

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

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

8.9 The offer to purchase contained herein is personal to the Vendor and shall not be assigned by the Vendor and does not enure to the benefit of the Vendor's successors or assigns.

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

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

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

8.13 The provisions of the attached Schedules "A" and "B" shall form part of this Agreement as if set out herein.

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

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

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

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

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

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

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

IN WITNESS WHEREOF the parties hereto have hereunto set their respective hands and seals to this Agreement of Purchase and Sale.

PURCHASER:

This Offer is dated the day of 20__.

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________________

Name:

Title: Manager, Facilities & Real Estate Acquisition

I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________________

Name:

Title: Director, Facilities & Real Estate

I have authority to bind the Corporation

VENDOR:

The undersigned Vendor hereby accepts the above offer and covenants, promises and agrees to and with the Purchaser to duly carry out the same on the terms and conditions above mentioned.

Dated and accepted as at this day of 20___.

WITNESS:	**VENDOR:**
______________________________	______________________________ l/s
Name: «Real_Estate_Representative»	Name: **«Owner_1_name_for_letters»**
Address: 1800 Main Street East Milton, ON L9T 7S3	
______________________________	______________________________ l/s
Name: «Real_Estate_Representative»	Name: **«Owner_2_name_for_letters»**
Address: 1800 Main Street East Milton, ON L9T 7S3	______________________________
______________________________	______________________________ l/s
Name: «Real_Estate_Representative»	Name: **«Owner_3_name_for_letters»**
Address: 1800 Main Street East Milton, ON L9T 7S3	

The undersigned Spouse of the Vendor hereby consents to the disposition evidenced herein pursuant to the provisions of the *Family Law Act*, R.S.O. 1990, c.F.3, and amendments thereto.

In consideration of One Dollar ($1.00), the receipt of which from the Purchaser is hereby acknowledged, the undersigned Spouse of the Vendor hereby agrees with the Purchaser that he/she will execute all necessary or incidental documents to give full force and effect to the sale evidenced herein.

WITNESS:	**SPOUSE OF VENDOR:**
	l/s
Name: «Real_Estate_Representative»	Name: **Property Vendor Spouse Name**
Address: 1800 Main Street East Milton, ON L9T 7S3	

SCHEDULE "A"

The Property is more particularly described as follows:

«Legal_Description»

SCHEDULE "B"

PERMITTED ENCUMBRANCES

The parties agree that title on Closing may be subject to, and will be acceptable to the Purchaser, as follows:

[NTD: the Easement Agreement.]

LIST OF PROPERTIES AND PERMITS ASSOCIATED WITH THE PROJECT ROUTE

	PIN (Property Identification Number)	LEGAL DESCRIPTION	TYPE OF PROPERTY (Municipal, Private, Etc.)	Does Hydro One Require New or Updated Property Rights	RIGHTS REQUIRED	Where Agreement is Outstanding - Summary of Negotiations to Date	Owner(s)
PHASE 1							
SH01	625060452	PT MINING LOCATION 6E WHITE'S SURVEY MACGREGOR SRO, PT 2 55R4851 EXCEPT PT 6, 55R13175, S/T & T/W TBR245903 (PARTIALLY RELEASED BY TY124627) SHUNIAH	Private	Yes	Permanent Easement	Offer Pending	[redacted]
SH02	625060198	PT MINING LOCATION 6E WHITE'S SURVEY MACGREGOR SRO PT 1 55R4851, S/T & T/W TBR245903(PARTIALLY RELEASED BY TY124627); SHUNIAH	Private	Yes	Permanent Easement	Offer Pending	
SH03	625060456	PT MINING LOCATION 3 H. P. SAVIGNY'S SURVEY MACGREGOR; PT MINING LOCATION 4 SAVIGNY'S SURVEY MACGREGOR SRO AS IN MCG2104 SOUTH OF LAKEHEAD EXPRESSWAY EXCEPT PTS 4 & 5, 55R13175; SHUNIAH	Municipal Government	Yes	Permanent Easement	Offer Pending	
SH04	625060458	PCL 25562 SEC TBF SRO; PT MINING LOCATION 2 SAVIGNEY'S SURVEY MACGREGOR; PT MINING LOCATION 4E WHITE'S SURVEY MACGREGOR PT 1, 55R10051; PT MINING LOCATION 3 SAVIGNEY'S SURVEY MACGREGOR PT 2, 55R10051 EXCEPT PT 6 55R13118 MUNICIPALITY OF SHUNIAH	Private	Yes	Permanent Easement	Offer Pending	
SH05	625060447	PT MINING LOCATION 1 H. P. SAVIGNY'S SURVEY MACGREGOR PT 4, PAR15R EXCEPT PT 2, TBR362073 & PT 3, 55R9702 & PTS1 & 2, 55R13068; PT MINING LOCATION 2 H. P. SAVIGNY'S SURVEY MACGREGOR PT 2, PAR16R EXCEPT PT 1, TBR362073 & PT 4, 55R13068 & PT 1 55R13118; PT MINING LOCATION 3 H. P. SAVIGNY'S SURVEY MACGREGOR PT 2, PAR17R EXCEPT MINING RIGHTS AS IN TBR155740 & EXCEPT PTS 3,4 & 5 55R13118 SUBJECT TO AN EASEMENT AS IN PTA131136 SUBJECT TO AN EASEMENT AS IN TBR360052 MUNICIPALITY OF SHUNIAH	Private	Yes	Permanent Easement	Offer Pending	
SH06	625060506	PCL 23212 SEC TBF; PT LT 29 CON 2 DAWSON ROAD LOTS PT 1, 2, 3, 4, 5, 6 55R9229; S/T LEW45799; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
SH08	625060258	MINING LOCATION 23Z MILES SURVEY MACGREGOR WEST OF PAR2R EXCEPT PT 1, 2, 3, 4, 55R7812; S/T PTA131058, TBR360253; SHUNIAH	Private	Yes	Permanent Easement	Offer Pending	
SH09	625060261	PT MINING LOCATION 24Z MILES SURVEY MACGREGOR AS IN MCG3891 WEST OF PAR2R EXCEPT PT 1, 55R9477 & PT 4, 55R2635; S/T PTA138298, TBR360253; SHUNIAH	Private	Yes	Permanent Easement	Offer Pending	
SH10	625060244	PT MINING LOCATION 26Z MILES SURVEY MACGREGOR SRO; PT MINING LOCATION 27Z MILES SURVEY MACGREGOR SRO PT 9, 10, 11, 12, 13, 55R4303 EXCEPT PT 1, 2 55R4803; S/T PTA133942, TBR361142; SHUNIAH EXCEPT FORFEITED MINING RIGHTS, IF ANY	Private	Yes	Permanent Easement	Offer Pending	
SH11	625060241	PT MINING LOCATION 26Z MILES SURVEY MACGREGOR; PT MINING LOCATION 27Z MILES SURVEY MACGREGOR PT 2, 3, 4, 5, 6, 7, 55R4303; S/T PTA133942, TBR360068; SHUNIAH EXCEPT FORFEITED MINING RIGHTS, IF ANY	Private	Yes	Permanent Easement	Offer Pending	
SH12	625060184	PT NE1/4 SEC 18 CON D MACGREGOR; PT NW1/4 SEC 18 CON D MACGREGOR AS IN TBR409002; S/T PTA138297, TBR367424; SHUNIAH EXCEPT FORFEITED MINING RIGHTS, IF ANY MUNICIPALITY OF SHUNIAH	Private	Yes	Permanent Easement	Offer Pending	
TB01	623250254	PCL 26620 SEC TBF; PT SE 1/4 MINING LOCATION N.8 GORHAM PT 3, 4, 6 55R10830; S/T LPA83652; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB02	623250255	PCL 23078 SEC TBF; PT SE 1/4 MINING LOCATION N-8 GORHAM PT 3, 5, 7 55R6990; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB03	623250257	PCL 8942 SEC TBF; SW 1/4 MINING LOCATION N 8 GORHAM; S/T F46704, LPA83916; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB04	623250286	PCL 11043 SEC TBF; PT E 1/2 MINING LOCATION A.L. 42 GORHAM AS IN LPA50725; S/T F46768, LPA53789, LPA83921; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB05	623250290	PCL 10480 SEC TBF; PT E PT LOCATION A.L. 42 GORHAM AS IN LPA46712 EXCEPT PT 1 55R1239, PT 1 55R1740 S/T DEBTS IN LPA46712; S/T F46809, LPA83918; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB06	623250291	PCL 9649 SEC TBF; W PT OF LOCATION A.L. 42 GORHAM AS IN PPA5770 EXCEPT PT 2 55R1239; S/T F46809, LPA83918; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	

	PIN (Property Identification Number)	LEGAL DESCRIPTION	TYPE OF PROPERTY (Municipal, Private, Etc.)	Does Hydro One Require New or Updated Property Rights	RIGHTS REQUIRED	Where Agreement is Outstanding - Summary of Negotiations to Date	Owner(s)
TB07	623250278	PCL 16364 SEC TBF; PT MINING LOCATION 47 E GORHAM SRO PT 1 TO 3 PAR680, PT 1 TO 5 PAR131, PT 1 TO 3 PAR292; S/T F47015, LPA84264; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB08	623250300	PCL 14560 SEC TBF; MINING LOCATION 70E MCINTYRE SRO; S/T F46766, LPA84265; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB09	623250301	PCL 4636 SEC TBF; N PT LT 8 CON 1 GORHAM BEING ALL THAT PART OF SAID LT LYING N OF A LINE DRAWN ACROSS SAID LT ON A COURSE E ASTRONOMICALLY FROM A POINT ON THE W LIMIT THEREOF 40 CHAINS NORTH OF THE SW ANGLE THEREOF; S/T F46804, LPA83895; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB11	623250331	PCL 4732 SEC TBF; N PT LT 10 CON 1 GORHAM AS IN PPA2879; S/T F51143, LPA83897; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB12	623240413	PART PCL 7877 SEC TBF; NE 1/4 LT 11 CON 1 GORHAM, BEING PARTS 1, 2, 3 AND 4 ON PLAN 55R-14590, EXCEPT LPA22629; S/T F51142, LPA76824, LT226664; SUBJECT TO AN EASEMENT OVER UNITS A, B, C & D, PLAN D17 AS IN EXPROPRIATION PLAN D17; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB13	623240414	PCL 7877 SEC TBF; NE 1/4 LT 11 CON 1 GORHAM, EXCEPT PARTS 1, 2, 3, AND 4 ON PLAN 55R-14595 AND PARTS 1, 2, 3 AND 4 ON PLAN 55R-14590, EXCEPT LPA22629; S/T F51142, LPA76824, LT226664; SUBJECT TO AN EASEMENT OVER UNITS A, B, C & D, PLAN D17 AS IN EXPROPRIATION PLAN D17; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB14	623240395	N 1/2 LT 12 CON 1 GORHAM EXCEPT PT 2 55R14265 SUBJECT TO AN EASEMENT AS IN F47273 SUBJECT TO AN EASEMENT AS IN LPA83888 UNORGANIZED TERRITORIES	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB15	623240173	PCL 24981 SEC TBF; FIRSTLY: E 1/2 LT 13 CON 1 GORHAM EXCEPT FIRSTLY: CONTAINING BY ADMEASUREMENT 50 ACRES, COMMENCING AT THE SOUTHEAST ANGLE OF THE SAID LOT; THENCE WEST ALONG THE SOUTH LIMIT OF THE SAID LOT 10 CHAINS AND 58.8 LINKS; THENCE NORTH AND PARALLEL TO THE EAST LIMIT OF THE SAID LOT 47 CHAINS AND 22.3 LINKS; THENCE EAST AND PARALLEL TO THE SOUTH LIMIT OF THE SAID LOT, 10 CHAINS AND 58.8 LINKS MORE OR LESS, TO THE EAST LIMIT OF THE SAID LOT; THENCE SOUTH ALONG THE EAST LIMIT OF THE SAID LOT 47 CHAINS AND 22.3 LINKS MORE OR LESS TO THE POINT OF COMMENCEMENT. SECONDLY: PORTION CONTAINING BY ADMEASUREMENT 8 ACRES, BE THE SAME MORE OR LESS, AND MORE PARTICULARLY DESCRIBED AS FOLLOWS: COMMENCING AT A POINT IN THE SOUTH LIMIT OF THE SAID LOT DISTANT 15 CHAINS AND 45 LINKS MEASURED WESTERLY THEREALONG FROM THE SOUTHEAST ANGLE OF THE SAID LOT: THENCE WESTERLY ALONG THE SOUTH LIMIT OF THE SAID LOT, 4 CHAINS AND 55 LINKS TO THE SOUTHWEST ANGLE OF THE SAID EAST HALF; THENCE NORTH ALONG THE WEST LIMIT OF THE SAID EAST HALF 17 CHAINS AND 58 LINKS; THENCE EASTERLY AND PARALLEL TO THE SOUTH LIMIT OF THE SAID LOT, 4 CHAINS AND 55 LINKS MORE OR LESS TO INTERSECT A LINE DRAWN NORTH AND PARALLEL TO THE EAST LIMIT OF THE SAID LOT FROM THE POINT OF COMMENCEMENT; THENCE SOUTH 17 CHAINS AND 58 LINKS MORE OR LESS PARALLEL TO THE EAST LIMIT OF THE SAID LOT TO THE POINT OF COMMENCEMENT.	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB16	623240248	PCL 5859 SEC TBF; PT W 1/2 LT 13 CON 1 GORHAM AS IN LPA19514; S/T F49325, LPA83909; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB17	623240362	PT N 1/2 LT 14 CON 1 GORHAM EXCEPT PT 1, 2 & 3 55R10840; PT N 1/2 LT 15 CON 1 GORHAM PT 1 55R7903; S/T F46811, LPA83911; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB18	623240159	PCL 19784 SEC TBF; PT S PT BROKEN LT 14 CON 2 GORHAM PT 5 TO 7 55R3926; S/T LPA83919; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB19	623240154	PCL 10446 SEC TBF; S PT BROKEN LT 14 CON 2 GORHAM AS IN LPA91907 EXCEPT PT 1 TO 7 55R3926; S/T F46706, LPA83919; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB20	623240133	PCL 15699 SEC TBF; PT S 1/2 LT 15 CON 2 GORHAM PT 7, 8 55R1106; S/T F46696, LPA83928; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB21	623240134	PCL 23842 SEC TBF; PT S 1/2 LT 15 CON 2 GORHAM PT 4 TO 6 55R1106, S/T PT 5 55R1106 AS IN LPA83928; S/T F46692; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]

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TB22	623240104	PCL 21275 SEC TBF; S 1/2 LT 16 CON 2 GORHAM EXCEPT LPA65956, LPA65423, PT 1, 2 55R8462; S/T F46726, LPA84148; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB23	623240056	PCL 5267 SEC TBF; E 1/2 OF S PT LT 17 CON 2 GORHAM AS IN LPA49357; S/T LPA83903 AMENDED BY LT186448; S/T F46719; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB24	623240057	PCL 4264 SEC TBF; S PT LT 17 CON 2 GORHAM AS IN PPA2484 EXCEPT LPA16356; S/T F46567, LPA84613; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB25	623240047	PCL 583 SEC TBEF; E 1/2 OF S 1/2 LT 18 CON 2 GORHAM; S/T LPA83886; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB26	623240441	E 1/2 OF N 1/2 LOT 18 CON 2 GORHAM EXCEPT PART 1, PAR600, PARTS 1 TO 4, 55R4045, PARTS 1 AND 2, 55R9076 AND PARTS 1 AND 2, 55R14890; S/T F46721, LPA83889; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB27	623240034	PCL 6230 SEC TBF; W 1/2 OF N 1/2 LT 18 CON 2 GORHAM EXCEPT PT 2 55R9515, PARTS 1 TO 5, 55R3320 & PART 4, PAR286; S/T F46700, LPA83910; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB28	623240043	PCL 18428 SEC TBF; PT LT 18 CON 2 GORHAM PT 4 55R3320 T/W PT 4 PAR286; S/T F46698, LPA83579; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB29	623220377	PCL 4374 SEC TBF; PT LT 1 CON 2 WARE AS IN PPA2584; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB30	623220376	PCL 17325 SEC TBF; PT N 1/2 LT 1 CON 2 WARE PT 3, 4 & 7 55R2230 EXCEPT PT 1 55R4808; S/T F46801; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB31	623220368	PCL 25380 SEC TBF; PT N 1/2 LT 2 CON 2 WARE PT 6 & 7 55R9799; S/T F32562; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB32	623220365	PCL 13223 SEC TBF; N 1/2 LT 3 CON 2 WARE EXCEPT PT 1 TO 13 55R1294; S/T LPA84262; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB33	623220360	PCL 15907 SEC TBF; PT N 1/2 LT 3 CON 2 WARE PT 13 55R1294; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB34	623220359	PCL 15908 SEC TBF; PT N 1/2 LT 3 CON 2 WARE PT 4, 5 & 12 55R1294; S/T LPA84262; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB35	623220358	PCL 21255 SEC TBF; PT N 1/2 LT 3 CON 2 WARE PT 3, 6 & 11 55R1294 S/T EASEMENT IN FAVOUR OF THE HYDRO ELECTRIC POWER COMMISSION OF ONTARIO OVER PT 6 55R1294; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB36	623220357	PCL 15904 SEC TBF; PT N 1/2 LT 3 CON 2 WARE PT 2, 7 & 10 55R1294; S/T LPA84262; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB37	623220356	PCL 15941 SEC TBF; PT N 1/2 LT 3 CON 2 WARE PT 1, 8 & 9 55R1294; S/T LPA84262; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB38	623220348	PCL 4406 SEC TBF; N 1/2 LT 4 CON 2 WARE EXCEPT PT 1 55R2583 & PT 1 TO 4 55R3053; S/T LPA83891; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB39	623220344	PCL 14176 SEC TBF; PT N 1/2 LT 5 CON 2 WARE AS IN LPA77231; S/T LPA83926; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB40	623220342	PCL 22779 SEC TBF; PT LT 5 CON 2 WARE PT 2, 3 & 4 55R6593; S/T LPA84146; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB41	623220341	PCL 9340 SEC TBF; PT N 1/2 LT 5 CON 2 WARE AS IN LPA37479 EXCEPT PT 1 TO 4 55R3676 & PT 1 TO 4 55R6593; S/T LPA84146; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB42	623220340	PCL 23530 SEC TBF; PT N 1/2 LT 5 CON 2 WARE PT 1, 2, 3 & 4 55R3676; S/T LPA84146; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB43	623220332	PCL 16058 SEC TBF; PT N 1/2 LT 6 CON 2 WARE PT 1, 2, 3 & 4 55R1479; S/T LPA84147; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB44	623220331	PCL 24278 SEC TBF; N 1/2 LT 6 CON 2 WARE EXCEPT PT 1 TO 4 55R1479 & PT 1 TO 4 55R3840; S/T LPA84147; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB45	623220329	PCL 18978 SEC TBF; PT N 1/2 LT 6 CON 2 WARE PT 2, 3 & 4 55R3840; S/T LPA84147; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB46	623220327	PCL 14513 SEC TBF; N 1/2 LT 7 CON 2 WARE; S/T LPA83929; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB47	623220298	PCL 19795 SEC TBF; PT LT 7 CON 3 WARE PT 1 & 2 55R4568; S/T LPA83912; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB48	623220723	PART LOT 7 CONCESSION 3 WARE, PARTS 1, 2 AND 3 55R14932; DISTRICT OF THUNDER BAY SUBJECT TO AN EASEMENT OVER PART 2 55R14932 AS IN LPA83912	Private	Yes	Permanent Easement	Offer Pending	

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TB49	623220724	PART LOT 7 CONCESSION 3 WARE, PARTS 1, 2 AND 3 55R4703, SAVE AND EXCEPT PARTS 1, 2 AND 3 55R14932; DISTRICT OF THUNDER BAY SUBJECT TO AN EASEMENT AS IN LPA83912	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB50	623220325	PCL 25355 SEC TBF; PT N 1/2 LT 8 CON 2 WARE PT 3, 4 & 5 55R8875; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB51	623220296	PCL 5058 SEC TBF; LT 8 CON 3 WARE; S/T LPA51263, LPA83899, LT225213; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB52	623220684	PT S 1/2 LT 9 CON 3 WARE PT 4, 5, 9, 10, 18 & 19 55R1506; EXCEPT PT 1 55R14181; S/T LPA84449; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB53	623220292	PCL 5020 SEC TBF; PT S 1/2 LT 9 CON 3 WARE PT 3, 8 & 15 55R1506; S/T LPA84449; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB54	623220291	PCL 18581 SEC TBF; PT S 1/2 LT 9 CON 3 WARE PT 2, 7, 13 & 14 55R1506; S/T LPA84449; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB55	623220290	PCL 16078 SEC TBF; PT S 1/2 LT 9 CON 3 WARE PT 1, 6, 11 & 12 55R1506; S/T LPA84449; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB56	623220289	PCL 17685 SEC TBF; PT S PT LT 10 CON 3 WARE PT 6, 7 & 8 55R2694; S/T LPA83924; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB57	623220288	PCL 17688 SEC TBF; PT S PT LT 10 CON 3 WARE PT 1, 2, 3 & 5 55R2694; S/T LPA83924; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB58	623220287	PCL 14019 SEC TBF; S PT LT 10 CON 3 WARE AS IN LPA74693 EXCEPT 1 TO 3, 5 TO 8 55R2694, 1 TO 5 55R2669, 1 TO 3 55R5186; S/T LPA51269, LPA83924, LT225169; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB59	623220285	PCL 20931 SEC TBF; PT S PT LT 10 CON 3 WARE PT 1, 2, 3, 4 & 5 55R2669; S/T LPA51269, LPA83924, LT225170; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB60	623210168	PCL 23557 SEC TBF; S 1/2 LT 11 CON 3 WARE EXCEPT PT 1, 2 & 3 55R7742, PT 2 & 3 55R9067, PT 1, 2 & 3 55R11314; S/T LPA51651, LPA83901, LT225171; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB61	623210170	PCL 25021 SEC TBF; PT S 1/2 LT 11 CON 3 WARE PT 3 55R9067; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB62	623210169	PCL 25013 SEC TBF; PT S 1/2 LT 11 CON 3 WARE PT 2 55R9067; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB64	623210162	PCL 13927 SEC TBF; S 1/2 LT 13 CON 3 WARE S/T, IF ENFORCEABLE, EXECUTION 170995; S/T LPA51301, LPA85436, LT225409; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB65	623210282	SOUTH PART LOT 14 CONCESSION 3 WARE AS IN PPA3318 EXCEPT PARTS 1 TO 4 PLAN 55R9332, PART 1 PLAN 55R14014 & PART 1 PLAN 55R14546; DISTRICT OF THUNDER BAY SUBJECT TO AN EASEMENT AS IN LPA51302 SUBJECT TO AN EASEMENT AS IN LPA83905 SUBJECT TO AN EASEMENT AS IN LT225114	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB66	623210271	PT LT 14 CON 3 WARE, DESIGNATED AS PT 1 PL 55R14014; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB67	623210156	PCL 25096 SEC TBF; PT LT 14 CON 3 WARE PT 1, 2 & 3 55R9332; S/T LPA83905; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB68	623210211	PCL 10400 SEC TBF; PT S 1/2 LT 16 CON 3 WARE AS IN LPA45966; S/T LPA51289; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB69	623210147	PCL 5941 SEC TBF; N 1/2 LT 16 CON 3 WARE EXCEPT PT 1 TO 5 55R8346, PT 1 TO 3 55R9470; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB70	623210146	PCL 25368 SEC TBF; PT N 1/2 LT 16 CON 3 WARE PT 1, 2 & 3 55R9470; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB71	623210143	PCL 24427 SEC TBF; PT N 1/2 LT 16 CON 3 WARE PT 1, 2 & 3 55R8346; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB72	623210142	PCL 5432 SEC TBF; N 1/2 LT 17 CON 3 WARE; S/T LPA82998; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB73	623210140	PCL 5349 SEC TBF; N 1/2 LT 18 CON 3 WARE; S/T LPA53906; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB74	623210137	PCL 5280 SEC TBF; PT OF N PT BROKEN LT 19 CON 3 WARE: S/T LPA64368; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB75	623210136	PCL 8764 SEC TBF; PT OF N PT BROKEN LT 19 CON 3 WARE AS IN LPA33303 S/T DEBTS IN LT217885; S/T LPA64370, LPA83914; DISTRICT OF THUNDER BAY SUBJECT TO AN EASEMENT OVER PARTS 1 AND 2, 55R14049 AS IN TY215643	Private	Yes	Permanent Easement	Offer Pending	[redacted]

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TB76	623180172	PCL 6645 SEC DFWF; JK 159 UNSURVEYED TERRITORY AS IN LEW34848; S/T LEW27109, LEW45802, LT223126; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB77	623180156	PCL 23812 SEC TBF; PT S PT LT 16 CON 1 FORBES PT 2, 3, 4 55R7757; S/T LEW45803; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB78	623180160	PCL 5812 SEC DFWF; S 1/2 OF S 1/2 LT 15 CON 1 FORBES AS IN LEW48069 S/T UNIT A D6 AS IN LEW45892; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB79	623180113	PCL 4906 SEC DFWF; S PT LT 14 CON 1 FORBES AS IN LEW28977; S/T LEW27105, LEW46693, LT223123; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB80	623180110	PCL 2265 SEC DFWF; S 1/2 LT 13 CON 1 FORBES AS IN PFW601 EXCEPT PT 1, 2 55R4397, PT 1, 2 55R5268, PT 1, 2, 3 55R7433; S/T LEW28500, LEW45688, LT222944; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB81	623180109	PCL 21088 SEC TBF; PT S 1/2 LT 13 CON 1 FORBES PT 1 55R5268; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB82	623180073	PCL 2284 SEC DFWF; S PT LT 12 CON 1 FORBES AS IN PFW614; S/T LEW47141; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB83	623180070	PCL 16924 SEC TBF; LT 11 CON 1 FORBES EXCEPT LEW6749; S/T LEW46061; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB84	623180072	PCL 18364 SEC TBF; PT LT 11 CON 1 FORBES PT 1 55R3201; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB85	623180071	PCL 7516 SEC DFWF; PT LT 11 CON 1 FORBES AS IN LEW44552 EXCEPT PT 1 55R3201; S/T LEW46061; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB86	623180035	PCL 2956 SEC DFWF; S PT BROKEN LT 10 CON 2 FORBES AS IN PFW946 EXCEPT LEW9757; S/T LEW47140; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB87	623190062	PCL 5598 SEC DFWF; PT LT 15 CON 2 DAWSON ROAD LOTS AS IN LEW27562; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB88	623190059	PCL 1728 SEC DFWF; LT 16 CON 2 DAWSON ROAD LOTS EXCEPT PT 1 55R3417; S/T LEW45793; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB89	623190058	PCL 2255 SEC DFWF; LT 17 CON 2 DAWSON ROAD LOTS; S/T LEW45794; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB91	623190057	PCL 2657 SEC DFWF; LT 18 CON 2 DAWSON ROAD LOTS; S/T LEW45855; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB92	623190055	PCL 7131 SEC DFWF; PT LT 19 CON 2 DAWSON ROAD LOTS AS IN LEW40230; S/T LEW45795; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB93	623190054	PCL 5048 SEC DFWF; LT 20 CON 2 DAWSON ROAD LOTS; S/T LEW47790; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB94	623190053	PCL 7493 SEC DFWF; LT 22 CON 2 DAWSON ROAD LOTS; S/T LEW45796; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB96	623190052	PCL 4247 SEC DFWF; PT LT 23 CON 2 DAWSON ROAD LOTS AS IN PFW1539; S/T LEW45797; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB97	623190395	PCL 26018 SEC TBF; 1STLY: PT LT 23 CON 2 DAWSON ROAD LOTS; 2NDLY: PT LT 13 CON 1 DAWSON ROAD LOTS; 3RDLY: PT LT 15 CON 1 DAWSON ROAD LOTS; 4THLY: PT LT 16 CON 1 DAWSON ROAD LOTS; 5THLY: PT LT 17 CON 1 DAWSON ROAD LOTS; 6THLY: PT LT 18 CON 1 DAWSON ROAD LOTS; 7THLY: PT LT 19 CON 1 DAWSON ROAD LOTS; 8THLY: PT LT 20 CON 1 DAWSON ROAD LOTS; 9THLY: PT LT 21 CON 1 DAWSON ROAD LOTS; 10THLY: PT LT 22 CON 1 DAWSON ROAD LOTS; 11THLY: PT LT 23 CON 1 DAWSON ROAD LOTS; 12THLY: PT LT 31 CON B DAWSON ROAD LOTS; 13THLY: PT LT 32 CON B DAWSON ROAD LOTS; 14THLY: PT LT 33 CON B DAWSON ROAD LOTS; 15THLY: PT LT 34 CON B DAWSON ROAD LOTS; 16THLY: PT LT 35 CON B DAWSON ROAD LOTS; 17THLY: PT LT 39 CON B DAWSON ROAD LOTS; 18THLY: PT LT 40 CON B DAWSON ROAD LOTS CONSISTING OF THE RIGHT-OF-WAY AND STATION GROUNDS OF THE CANADIAN NATIONAL RAILWAY COMPANY (FORMERLY THE GRAND TRUNK PACIFIC RAILWAY COMPANY) AS IN F74605 AS SHOWN ON PL652; DISTRICT OF THUNDER BAY SUBJECT TO AN EASEMENT IN GROSS AS IN TY268304	Private	Yes	Permanent Easement	Offer Pending	
TB98	623190050	PCL 3429 SEC DFWF; LT 24 CON 2 DAWSON ROAD LOTS; S/T LEW45865; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	

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TB99	623190049	PCL 2415 SEC DFWF; LT 25 CON 2 DAWSON ROAD LOTS; S/T LEW45798; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB100	623190048	PCL 16817 SEC TBF; LT 26 CON 2 DAWSON ROAD LOTS; S/T LEW45994; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB101	623190137	PCL 2381 SEC DFWF; LT 27 CON 2 DAWSON ROAD LOTS; S/T LEW49823; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB103	623190136	PCL 25887 SEC TBF; PT LT 28 CON 2 DAWSON ROAD LOTS PT 10, 11, 12 55R9229; S/T LEW45799; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB104	623190135	PCL 25110 SEC TBF; PT LT 28 CON 2 DAWSON ROAD LOTS; PT LT 29 CON 2 DAWSON ROAD LOTS PT 7, 8, 9 55R9229; S/T LEW45799; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB105	623190132	PCL 23212 SEC TBF; PT LT 29 CON 2 DAWSON ROAD LOTS PT 1, 2, 3, 4, 5, 6 55R9229; S/T LEW45799; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB106	623190131	PCL 3663 SEC DFWF; PT LT 30 CON 2 DAWSON ROAD LOTS PT 1, 3 TO 14 55R3772; S/T LEW45799; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB107	623190129	PCL 6676 SEC DFWF; PT LT 31 CON 2 DAWSON ROAD LOTS AS IN LEW37443; S/T LEW46188, LT225872; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB108	Unknown	Unknown	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB109	623190128	PCL 7258 SEC DFWF; PT LT 32 CON 2 DAWSON ROAD LOTS AS IN LEW41882; S/T LEW45870; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB111	623190127	PCL 6949 SEC DFWF; PT LT 33 CON 2 DAWSON ROAD LOTS AS IN LEW39214; S/T LEW46005; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB112	623190126	PCL 6891 SEC DFWF; PT LT 34 CON 2 DAWSON ROAD LOTS AS IN LEW37788; S/T LEW45498; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB113	623190125	PCL 7538 SEC DFWF; PT LT 35 CON 2 DAWSON ROAD LOTS AS IN LEW45620; S/T LEW46545; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB114	623190124	PCL 7214 SEC DFWF; LT 36 CON 2 DAWSON ROAD LOTS EXCEPT LEW11188; S/T LEW45800; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB115	623190152	PCL 7855 SEC DFWF; FIRSTLY: LT 36 CON 1 DAWSON ROAD LOTS; SECONDLY: PT LT 59 CON B DAWSON ROAD LOTS AS IN LEW49924; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB116	623190123	PCL 7579 SEC DFWF; LT 37 CON 2 DAWSON ROAD LOTS; S/T LEW47950; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB118	623190153	PCL 3378 SEC DFWF; LT 37 CON 1 DAWSON ROAD LOTS; S/T LEW45790; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB120	623190154	PCL 4873 SEC DFWF; LT 42 CON 1 DAWSON ROAD LOTS; S/T LEW46321; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB122	623190155	PCL 7759 SEC DFWF; LT 49 CON 1 DAWSON ROAD LOTS; S/T LEW48493; DISTRICT OF THUNDER BAY *SEC AMENDED TO "DFWF" BY ROBERT JOHNSON 2007 04 04.	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB123	623190036	PCL 24157 SEC TBF; LT 73 CON B DAWSON ROAD LOTS; S/T LEW46270; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB124	623190035	PCL 20475 SEC TBF; LT 74 CON B DAWSON ROAD LOTS SRO; S/T LEW46270; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB125	623190033	PCL 5800 SEC DFWF; PT LT 75 CON B DAWSON ROAD LOTS AS IN LEW29343; S/T LEW45792; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB126	623170009	PCL 5647 SEC DFWF; S 1/2 LT 10 CON 2 GOLDIE; S/T LEW46732; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB127	623170008	PCL 4630 SEC DFWF; S 1/2 LT 11 CON 2 GOLDIE; S/T LEW45804; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB128	623170039	SURFACE RIGHTS ONLY PT OF S PT LT 12 CON 2 GOLDIE AS IN LT95000; S/T LEW45805; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB129	623170002	PCL 20263 SEC TBF; PT S PT LT 12 CON 2 GOLDIE AS IN LT171395 EXCEPT PT 7 55R11687, S/T PT 1 55R10475 AS IN F71204; DISTRICT OF THUNDER BAY	Crown	Yes	Permanent Easement	Offer Pending	[redacted]
TB130	623170007	PCL 5145 SEC DFWF; PT S PT LT 12 CON 2 GOLDIE AS IN PFW2067 (FIRSTLY) EXCEPT PT 1 55R3081, PT 1 55R4911, PT 1 55R8771; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB131	623160031	PCL 20253 SEC TBF; MINING CLAIM TB15042 UNSURVEYED TERRITORY SITUATE WEST OF GOLDIE TOWNSHIP EXCEPT PT 2, 3 55R3081, PT 1 55R6014; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]

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TB132	623150199	PCL 23934 SEC TBF; MINING CLAIM TB 27846 CONACHER SRO; S/T LEW45791; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB133	623150218	PCL 4288 SEC DFWF; MINING CLAIM TB 22333 CONACHER; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB134	623150128	PCL 4047 SEC DFWF; MINING CLAIM TB 28089 CONACHER EXCEPT LEW24239; S/T LEW24948, LEW45681; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB135	623150312	SURFACE RIGHTS ONLY MINING CLAIM TB16322 CONACHER EXCEPT LEW24239; S/T LEW46398; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB136	623150308	SURFACE RIGHTS ONLY MINING CLAIM TB16321 CONACHER BEING LAND & LAND COVERED WITH THE WATER OF PART OF THE SWAMP RIVER, EXCEPT LEW24239; S/T LEW46398; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB137	623150310	SURFACE RIGHTS ONLY MINING CLAIM TB16320 CONACHER EXCEPT LEW24139; S/T LEW46398; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB138	623150124	PCL 3996 SEC DFWF; MINING CLAIM TB 28091 CONACHER AS IN F32470 (ELEVENTHLY) EXCEPT LEW24239; S/T LEW24948; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB139	623150127	PCL 4048 SEC DFWF; MINING CLAIM TB 28090 CONACHER EXCEPT LEW24239; S/T LEW24948; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB140	623150275	PCL 742 SEC DFWF; THE RIGHT OF WAY OF THE CANADIAN NORTHERN RAILWAY (ONTARIO AND RAINY RIVER DIVISION) CONACHER INCLUDING ALSO EXTRA LAND FOR STATION GROUNDS, SIDINGS, BALLAST PITS AND SPUR LINES ADJOINING SAID RIGHT OF WAY AS IN PPA877 AS SHOWN ON PA142;	Private	Yes	Permanent Easement	Offer Pending	
TB141	623150125	PCL 18629 SEC TBF; FIRSTLY: PT MINING CLAIM TB2386 CONACHER PT 1 55R4010; SECONDLY: MINING CLAIM TB22425 CONACHER RESERVING THE SRO ON AND OVER THE ROW OF THE CANADIAN NATIONAL RAILWAYS CROSSING SAID CLAIM; THIRDLY: MINING CLAIM TB28072 CONACHER BEING LAND AND LAND COVERED WITH THE WATERS OF PT OF SWAMP RIVER WITHIN THE LIMITS OF THIS MINING CLAIM, RESERVING THE ROW OF THE CANADIAN NATIONAL RAILWAYS CROSSING THE SAID CLAIM, ALSO RESERVING THE SRO ON AND OVER A STRIP OF LAND ONE CHAIN IN PERPENDICULAR WIDTH ALONG THE SHORE OF THE SWAMP RIVER; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB142	623150117	PCL 4149 SEC DFWF; MINING CLAIM TB 28100 CONACHER EXCEPT LEW24139; DISTRICT OF THUNDER BAY	Crown	Yes	Permanent Easement	Offer Pending	
TB143	623130148	PCL 4610 SEC DFWF; PT MINING CLAIM TB 39173 HAGEY AS IN LT101988 & PT 9 FWR360; S/T LEW49450; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB144	623130147	PCL 4609 SEC DFWF; PT MINING CLAIM TB 40058 HAGEY AS IN LT101989 & PT 10 55R360; S/T LEW49450; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB145	623130146	PCL 4611 SEC DFWF; PT MINING CLAIM TB 39172 HAGEY AS IN LT101990 & PT 13 FWR360 EXCEPT LEW22202 & LEW22997; S/T LEW49450; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB146	623130577	MINING LOCATION 69Z MILES SURVEY HAINES; S/T MUS2228, MUS2335, OFW62642; DISTRICT OF THUNDER BAY	Crown	Yes	Permanent Easement	Offer Pending	
TB147	623130576	PT MINING LOCATION 68Z MILES SURVEY HAINES AS IN TBR163599(FOURTHLY); S/T MUS2228, MUS2335, OFW62642; DISTRICT OF THUNDER BAY	Crown	Yes	Permanent Easement	Offer Pending	
TB148	623130574	PT MINING LOCATION 67Z MILES SURVEY HAINES AS IN TBR163599 (FIFTHLY); S/T MUS2228, MUS2335, OFW62642; DISTRICT OF THUNDER BAY	Crown	Yes	Permanent Easement	Offer Pending	
TB149	625050591	PCL 2211 SEC DFWF; MINING LOCATION AL 641 UNSURVEYED TERRITORY SITUATE ON THE W SIDE OF KASHABOIWE RIVER, N OF LAKE SHEBANDOWAN, EXCEPT SRO ON AND OVER A STRIP OF LAND ONE CHAIN IN PERPENDICULAR WIDTH ALONG THE SHORE OF KASHABOIWE RIVER, AND EXCEPT THE ROW AND LANDS OF THE CANADIAN NATIONAL RAILWAY, AND EXCEPT LEW49214; S/T LEW14559, LEW25106, LEW47169; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	

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TB150	625050589	PCL 7277 SEC DFWF SRO; PT MINING LOCATION 70 Z UNSURVEYED TERRITORY W OF THE TWP OF HAINES AS IN LEW42792 EXCEPT PT 1 & 2, 55R4412, PT 1, 55R3522, PT 1, 55R4816; S/T LEW46510; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	[redacted]
TB151	625050951	PCL 6517 SEC DFWF; PT MINING LOCATION 70Z UNSURVEYED TERRITORY W OF THE TWP OF HAINES AS IN LEW32952 (SECONDLY) EXCEPT MRO AS IN LEW39202; S/T PT 2, 3, 4, 5 & 6, 55R3212 AS IN LT136081; S/T LEW14653, LEW25029, LEW45806; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB152	625051127	PT MINING LOCATION 71Z BETWEEN LAKE SHEBANDOWAN & LAKE KASHABOWIE UNSURVEYED TERRITORY SRO AS IN TBR336601 (SECONDLY) E OF OFW42564; S/T OFW64107, RUS2227, RUS2334; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB153	625051132	PT MINING LOCATION 71Z BETWEEN LAKE SHEBANDOWAN & LAKE KASHABOWIE UNSURVEYED TERRITORY SRO AS IN OFW48160; S/T OFW63944; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB154	625051128	PT MINING LOCATION 71Z BETWEEN LAKE SHEBANDOWAN & LAKE KASHABOWIE UNSURVEYED TERRITORY AS IN OFW49102; S/T OFW68616; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB155	625051124	PT MINING LOCATION 71Z BETWEEN LAKE SHEBANDOWAN & LAKE KASHABOWIE UNSURVEYED TERRITORY PT 4, 55R7030; PT MINING LOCATION 71Z BETWEEN LAKE SHEBANDOWAN & LAKE KASHABOWIE UNSURVEYED TERRITORY PT 3, 55R7030 EXCEPT MRO OVER PT AS IN OFW50279; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB156	625051123	PT MINING LOCATION 71Z BETWEEN LAKE SHEBANDOWAN & LAKE KASHABOWIE UNSURVEYED TERRITORY PT 1, 55R7030 EXCEPT MRO OVER PT AS IN OFW50279; DISTRICT OF THUNDER BAY.	Private	Yes	Permanent Easement	Offer Pending	
TB157	625051151	PT MINING LOCATION K 56 SHEBANDOWAN LAKE (C. C. FORNERIS SURVEY) UNSURVEYED TERRITORY; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB158	625050550	PCL 4578 SEC DFWF; MINING CLAIM TB 39176 UNSURVEYED TERRITORY BEING LAND AND LAND COVERED WITH THE WATER OF PT OF AN UNNAMED LAKE WITHIN THE LIMITS OF THIS MINING CLAIM, SITUATE IN THE UPPER SHEBANDOWAN LAKE AREA, SAVING AND EXCEPTING THEREOUT AND THEREFROM THE SRO ON AND OVER THE TRANSMISSION LINE OF THE HYDRO-ELECTRIC POWER COMMISSION CROSSING THE SAID CLAIM, EXCEPT LEW24011, LEW35047, LEW35005; S/T LEW27075, LEW45773; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
TB159	625050551	PCL 4579 SEC DFWF; MINING CLAIM TB 39177 UNSURVEYED TERRITORY BEING LAND AND LAND COVERED WITH THE WATER OF PT OF AN UNNAMED LAKE WITHIN THE LIMITS OF THIS MINING CLAIM, SITUATE IN THE UPPER SHEBANDOWAN LAKE AREA, SAVING AND EXCEPTING THEREOUT AND THEREFROM THE SRO ON AND OVER THE ROW OF THE TRANSMISSION LINE OF THE HYDRO-ELECTRIC POWER COMMISSION CROSSING THE SAID CLAIM, EXCEPT LEW24011; S/T LEW27075, LEW45773; DISTRICT OF THUNDER BAY	Private	Yes	Permanent Easement	Offer Pending	
AT01	560661111	PCL 16584 SEC RAINY RIVER; SUMMER RESORT LOCATION SH 22 UNSURVEYED TERRITORY N NYM LAKE S TWP MCCAUL; S/T A2508; DISTRICT OF RAINY RIVER	Private	Yes	Permanent Easement	Offer Pending	
AT02	560660967	PCL 16163 SEC RAINY RIVER; SUMMER RESORT LOCATION SH-21 UNSURVEYED TERRITORY N NYM LAKE S TWP MCCAUL; S/T SLT88789; DISTRICT OF RAINY RIVER	Private	Yes	Permanent Easement	Offer Pending	
AT03	560662673	PCL 427 SEC RAINY RIVER SRO; MINING LOCATION R 760 UNSURVEYED TERRITORY; MINING LOCATION R 761 UNSURVEYED TERRITORY *2 1/2 MILES S CANADIAN NORTHERN RAILWAY S STEEP ROCK LAKE; S/T D34; DISTRICT OF RAINY RIVER ; *AMENDED 2003/09/24 BY LAND REGISTRAR #7	Private	Yes	Permanent Easement	Offer Pending	
				PHASE 2			
AT04	560660751	PCL 14892 SEC RAINY RIVER; MINING CLAIM FF-5272 UNSURVEYED TERRITORY EXCEPT PT 1 RR361 RESERVING AND EXCEPTING THEREOUT AND THEREFROM THE RIGHT OF WAY OF THE CANADIAN NATIONAL RAILWAYS CROSSING THE SAID LANDS; DISTRICT OF RAINY RIVER	Private	Yes	Permanent Easement	Offer Pending	

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AT06	560051269	PCL 23659 SEC RAINY RIVER; PT LOCATION HY 192 SCHWENGER PT 1, 2 & 3 48R3721; S/T A81057; ATIKOKAN	Private	Yes	Permanent Easement	Offer Pending	[redacted]
AT08	560051295	PCL 25974 SEC RAINY RIVER; FIRSTLY PT MINING CLAIM FF 3203 SCHWENGER; PT MINING CLAIM FF 3288 SCHWENGER; PT MINING CLAIM FF 3311 SCHWENGER; PT MINING CLAIM FF 3332 SCHWENGER; PT MINING CLAIM FF 3333 SCHWENGER; MINING CLAIM FF 3204 SCHWENGER; MINING CLAIM FF 3205 SCHWENGER; MINING CLAIM FF 3280 SCHWENGER; MINING CLAIM FF 3281 SCHWENGER; MINING CLAIM FF 3282 SCHWENGER; MINING CLAIM FF 3283 SCHWENGER; MINING CLAIM FF 3284 SCHWENGER; MINING CLAIM FF 3285 SCHWENGER; MINING CLAIM FF 3286 SCHWENGER; MINING CLAIM FF 3287 SCHWENGER; MINING CLAIM FF 3334 SCHWENGER; MINING LOCATION X 261 SCHWENGER; MINING LOCATION X 262 SCHWENGER; MINING LOCATION HP 633 SCHWENGER; THE RDAL ADJACENT TO X261, X262 & HP633 SCHWENGER ALONG THE SHORE OF STEEP ROCK LAKE AND THE SEINE RIVER; PT 1-14, PL D48; SECONDLY LOCATION HY 200 SCHWENGER SURFACE RIGHTS ONLY, BEING ALL OF MINING CLAIM F.F. 6285 AND PT OF MINING CLAIMS F.F. 3203 & F.F. 3288, BEING PT OF THE OF THE BED OF SEINE RIVER & PT OF THE BED OF MINK LAKE, PT 1-16, 48R2746; S/T A12513E, A27085, A81057, SLT65638, SLT84254, SLT84796E, SLT86176E, SLT88396E, SLT88491; ATIKOKAN	Private	Yes	Permanent Easement	Offer Pending	[redacted]
AT09	560052031	PCL 703 SEC RAINY RIVER; MINING LOCATION 252X SCHWENGER; MINING LOCATION 253X SCHWENGER; MINING LOCATION 254X SCHWENGER; MINING LOCATION 255X SCHWENGER; MINING LOCATION 256X SCHWENGER; MINING LOCATION 257X SCHWENGER; MINING LOCATION 258X SCHWENGER; MINING LOCATION 259X SCHWENGER; MINING LOCATION 260X SCHWENGER; ATIKOKAN	Crown	Yes	Permanent Easement	Offer Pending	[redacted]
AT10	560052133	PCL 1554 SEC RAINY RIVER; MINING LOCATION 873X SCHWENGER; MINING LOCATION 872X SCHWENGER SOUTH OF STEEP ROCK LAKE ON THE SEINE RIVER; SURFACE RIGHTS ONLY; S/T A24004, SLT67364; ATIKOKAN	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
AT11	560052275	PCL 1553 SEC RAINY RIVER; MINING LOCATION 858X UNSURVEYED TERRITORY; S/T A3256; DISTRICT OF RAINY RIVER.	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
AT12	560052272	PCL 15957 SEC RAINY RIVER; MINING LOCATION 862-X UNSURVEYED TERRITORY;MINING LOCATION 863-X UNSURVEYED TERRITORY; MINING LOCATION 860-X UNSURVEYED TERRITORY; MINING LOCATION 861-X UNSURVEYED TERRITORY; MINING LOCATION 817-X UNSURVEYED TERRITORY; MINING LOCATION 818-X UNSURVEYED TERRITORY; MINING LOCATION 864-X UNSURVEYED TERRITORY; MINING LOCATION 865-X UNSURVEYED TERRITORY; MINING LOCATION 866-X UNSURVEYED TERRITORY; MINING LOCATION 871-X UNSURVEYED TERRITORY; MINING LOCATION G-324 UNSURVEYED TERRITORY; MINING LOCATION HW-725 UNSURVEYED TERRITORY; MINING LOCATION 815-X UNSURVEYED TERRITORY; MINING LOCATION 816-X UNSURVEYED TERRITORY AS IN SLT62391 SURFACE RIGHTS ONLY EXCEPT SLT62512, PL SM197, PL SM200, PL SM201, SLT67408, SLT68024, SLT66188, PT 3 & 4 RR155, PT 1 TO 6 RR196, PT 1 RR201, PT 1,2 & 3 RR430, PT 1 & 2 48R943, PT 1 48R2087, PT 1, 2, 3 & 5 48R2184, PT1 48R2217, PT 1 & 2, 48R2218, PT 3 48R2349, PT 1 48R2865, PT 1 48R3149 PT 1 & 2 48R3168, PT 1, 2 & 3 48R3737 LYING N OF THE RAINY RIVER; S/T SLT82413, SLT89649; DISTRICT OF RAINY RIVER	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]

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AT13	560052272	PCL 15957 SEC RAINY RIVER; MINING LOCATION 862-X UNSURVEYED TERRITORY;MINING LOCATION 863-X UNSURVEYED TERRITORY; MINING LOCATION 860-X UNSURVEYED TERRITORY; MINING LOCATION 861-X UNSURVEYED TERRITORY; MINING LOCATION 817-X UNSURVEYED TERRITORY; MINING LOCATION 818-X UNSURVEYED TERRITORY; MINING LOCATION 864-X UNSURVEYED TERRITORY; MINING LOCATION 865-X UNSURVEYED TERRITORY; MINING LOCATION 866-X UNSURVEYED TERRITORY; MINING LOCATION 871-X UNSURVEYED TERRITORY; MINING LOCATION G-324 UNSURVEYED TERRITORY; MINING LOCATION HW-725 UNSURVEYED TERRITORY; MINING LOCATION 815-X UNSURVEYED TERRITORY; MINING LOCATION 816-X UNSURVEYED TERRITORY AS IN SLT62391 SURFACE RIGHTS ONLY EXCEPT SLT62512, PL SM197, PL SM200, PL SM201, SLT67408, SLT68024, SLT66188, PT 3 & 4 RR155, PT 1 TO 6 RR196, PT 1 RR201, PT 1,2 & 3 RR430, PT 1 & 2 48R943, PT 1 48R2087, PT 1, 2, 3 & 5 48R2184, PT1 48R2217, PT 1 & 2, 48R2218, PT 3 48R2349, PT 1 48R2865, PT 1 48R3149 PT 1 & 2 48R3168, PT 1, 2 & 3 48R3737 LYING N OF THE RAINY RIVER; S/T SLT82413, SLT89649; DISTRICT OF RAINY RIVER	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
AT14	560052154	PCL 23874 SEC RAINY RIVER; PT MINING LOCATION 818X SCHWENGER PT 1, 2 & 3 48R2184; PT MINING LOCATION 817X SCHWENGER PT 5 48R2184 & PT 1 48R2217; SURFACE RIGHTS ONLY; S/T SLT89649; ATIKOKAN	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
AT15	560660797	PCL 1540 SEC RAINY RIVER SURFACE RIGHTS ONLY; MINING LOCATIONS 819X UNSURVEYED TERRITORY SITUATE N OF ATIKOKAN RIVER NEAR 28TH & 29TH MILES ON NIVEN'S SOUTH BASE LINE; S/T A24004; DISTRICT OF RAINY RIVER	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]
AT16	560663467	MINING LOCATION 106E UNSURVEYED TERRITORY; MINING LOCATION 107E UNSURVEYED TERRITORY; MINING LOCATION 108E UNSURVEYED TERRITORY; MINING LOCATION 109E UNSURVEYED TERRITORY; MINING LOCATION 110E UNSURVEYED TERRITORY; MINING LOCATION 111E UNSURVEYED TERRITORY; MINING LOCATION 118E UNSURVEYED TERRITORY RESERVING AN ALLOWANCE OF ONE CHAIN PERPENDICULAR WIDTH FOR A RD ON THE BANKS OF THE ATIKOKAN RIVER EXCEPT SLT61349; PT 1 48R939; S/T A23703, SLT91527; DISTRICT OF RAINY RIVER	Private	Yes	Permanent Easement	Offer Pending	[redacted]
AT17	560662988	PCL 2066 SEC RAINY RIVER; CNR RIGHT OF WAY UNSURVEYED TERRITORY /FREEBORN; RIGHT OF WAY FROM THE EASTERN BOUNDARY OF THE DISTRICT OF RAINY RIVER, W TO MINING LOCATION 636X TWP OF HUTCHINSON BEING 237.60 ACRES; ABIWIN STATION GROUNDS BEING 9.23 ACRES; KAWENE STATION GROUNDS BEING 9.69 ACRES; RIGHT OF WAY FROM MINING LOCATION 633X W TO MINING LOCATION R. 404 BEING 47.80 ACRES; ADJOINING MINING LOCATION 231X BEING 1.70 ACRES; ADJOINING MINING LOCATION 234X BEING .17 ACRES; ADJOINING MINING LOCATION 235X BEING 1.00 ACRES; ADJOINING MINING LOCATION 108E BEING .70 ACRES; W OF MINING LOCATION 107. E. BEING 10.66 ACRES; ADJOINING MINING LOCATION 109.E BEING .40 ACRES; ADJOINING MINING LOCATION 111.E BEING .80 ACRES; ADJOINING MINING LOCATION 869X BEING 3.02 ACRES; RIGHT OF WAY W FROM MINING LOCATION B.G.122 TO MINING LOCATION F.F.83 BEING 232.89 ACRES; STEEP ROCK STATION GROUNDS BEING 9.23 ACRES; BANNING STATION GROUNDS BEING 10.88 ACRES; ADJOINING MINING LOCATION J.0.9 BEING 2.36 ACRES; ADJOINING MINING LOCATION J.0.8 BEING 5.19 ACRES; ADJOINING MINING LOCATION P.755 BEING 5.21 ACRES; ADJOINING MINING LOCATION K.261 BEING .66 ACRES; ADJOINING MINING LOCATION K.608 BEING 2.35 ACRES; ADJOINING MINING LOCATION F.F 10 BEING 4.04 ACRES; ADJOINING MINING LOCATION H.P.126 BEING 3.83 ACRES; WEST OF MINING LOCATION G.103 BEING 12.14 ACRES; ADJOINING MINING LOCATION K.660 BEING 15.05 ACRES; FARRINGTON STATION GROUNDS BEING 10.15 ACRES; W OF MINING LOCATION K.462 BEING 5.54	Private	Yes	Permanent Easement	Offer Pending	[redacted]
AT18	560660752	PCL 14894 SEC RAINY RIVER; MINING CLAIM FF-5275 UNSURVEYED TERRITORY EXCEPT PT 1 48R1867 SAVING AND EXCEPTING THEREOUT AND THEREFROM THE RIGHT OF WAY OF THE CANADIAN NATIONAL RAILWAYS CROSSING THE SAID LANDS; S/T SLT95183; DISTRICT OF RAINY RIVER	Municipal Government	Yes	Permanent Easement	Offer Pending	[redacted]

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AT19	560662344	PCL 24989 SEC RAINY RIVER; PT MINING CLAIM FF-5274 UNSURVEYED TERRITORY PT 1, 2 & 3 48R2638 T/W EASEMENT OVER PT 6 48R1867 FOR INGRESS & EGRESS FOR OWNERS PT 1,2,3,4 & 5 48R2638; S/T SLT95183; DISTRICT OF RAINY RIVER	Private	Yes	Permanent Easement	Offer Pending	[redacted]
AT20	560661914	PCL 23222 SEC RAINY RIVER; PT MINING CLAIM FF 5274 UNSURVEYED TERRITORY PT 4 & 5, 48R2638, T/W PT 4 & 5, 48R1867 AS IN A24978; DISTRICT OF RAINY RIVER	Private	Yes	Permanent Easement	Offer Pending	
DR01	420990005	PCL 17855 SEC DKF; SUMMER RESORT LOCATION RK728 ILSLEY; S/T LT110529; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR02	420980003	PCL 28910 SEC DKF SRO; MINING LOCATION 93E HODGSON; MINING LOCATION 99E HODGSON; S/T LT46248; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR03	420960009	PCL 8835 SEC DKF; S1/2 LT 1 CON 1 REVELL; S/T LT102252, LT105489, LT188262, LT188263, LT190940, LT60964; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR05	420960017	PCL 9948 SEC DKF; N1/2 LT 6 CON 2 REVELL; S/T LT107423, LT199866; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR10	420950057	PCL 11619 SEC DKF; PT LT 1 CON 4 MELGUND AS IN PA8806; S/T LT102715, LT108136, LT189018, LT45840, LT61325; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR11	420950059	PCL 4476 SEC DKF; N PT LT 2 CON 4 MELGUND AS IN PA3680; S/T LT101250, LT106169, LT189017, LT45838, LT56670; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR12	420950051	PCL 5827 SEC DKF; PT S1/2 LT 4 CON 5 MELGUND AS IN PA4677; S/T LT101419, LT106168, LT190251, LT45926, LT56668; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR13	420950041	PCL 5704 SEC DKF THE RIGHT OF WAY OF THE DYMENT BRANCH OF THE CANADIAN PACIFIC RAILWAY ACROSS; PT LT 6 CON 2 MELGUND; PT LT 5 CON 4 MELGUND; PT LT 6 CON 1 MELGUND; PT LT 4 CON 4 MELGUND; PT LT 4 CON 5 MELGUND; PT LT 5 CON 3 MELGUND; PT LT 7 CON 1 MELGUND; PT MINING LOCATION SV242 MELGUND; PT MINING LOCATION SV240 MELGUND AS IN PA4584 AS SHOWN ON PL36; S/T LT204872; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR14	420950042	PT N1/2 LT 4 CON 5 MELGUND AS IN PA7606; EXCEPT LT30952, LT56230, LT56231 & PT 1, 23R8417; S/T LT102715, LT45836; CITY OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR15	420950048	PT N1/2 LT 5 CON 5 MELGUND AS IN PA16059; S/T LT101337; CITY OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR16	420950046	PCL 18491 SEC DKF; N PT LT 6 CON 5 MELGUND AS IN PA13614; S/T LT101094; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR17	420950024	PCL 16228 SEC DKF; PT S1/2 LT 6 CON 6 MELGUND AS IN LT12260; S/T LT112664, LT45841; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR18	420950025	PCL 16353 SEC DKF; S1/2 LT 7 CON 6 MELGUND; S/T LT101092, LT45839; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR19	420950027	PCL 4560 SEC DKF; S PT BROKEN LT 8 CON 6 MELGUND AS IN PA3742; S/T LT102816, LT45924; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR20	420950026	PCL 11726 SEC DKF; N PT BROKEN LT 8 CON 6 MELGUND AS IN PA8927; S/T LT101093, LT45925; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR22	420930202	PCL 19800 SEC DKF; E1/2 OF S1/2 LT 2 CON 2 SOUTHWORTH; PLANNING ACT VALIDATION IN KN16300; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR23	420930199	PCL 21644 SEC DKF; PT LT 4 CON 3 SOUTHWORTH AS IN LT61928; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR24	420930185	PCL 18406 SEC DKF; PT S PT LT 5 CON 4 SOUTHWORTH AS IN PA13564; S/T LT101742; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR25	420930184	PCL 6318 SEC DKF; N PT LT 5 CON 4 SOUTHWORTH AS IN PA4993; RESERVING THE ROW OF CANADIAN PACIFIC RAILWAY; S/T LT104819, LT45837; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR26	420930186	PCL 12020 SEC DKF; MINING LOCATION HW405 SOUTHWORTH; N PT LT 6 CON 4 SOUTHWORTH AS IN PA9252; EXCEPT LT32338; S/T LT101417, LT45828; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR27	420930177	PCL 16243 SEC DKF; S PT BROKEN LT 6 CON 5 SOUTHWORTH AS IN LT43034; S/T LT101743, LT45849; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	

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DR28	420930440	PCL 15382 SEC DKF; MINING LOCATION HW12 SOUTHWORTH; PT MINING LOCATION HW310 SOUTHWORTH AS IN PA11695; S/T LT101416, LT45850; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR29	420930181	PCL 3567 SEC DKF; LOCATION SV7 SOUTHWORTH; S/T LT102815, LT46207; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR30	420930398	PCL 9671 SEC DKF; PT LOCATION HW8 SOUTHWORTH AS IN LT21462; SITUATE N OF THE CANADIAN PACIFIC RAILWAY ROW AND IMMEDIATELY E OF HW7 AT WABIGOON MISSION AND N OF THE MCKENZIE RIVER; S/T LT100961, LT45831; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR31	420930376	PCL 12730 SEC DKF SRO; LOCATION HW243 SOUTHWORTH; S/T LT102208, LT52241; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR32	420930377	PCL 18503 SEC DKF; PT LT 8 CON 5 SOUTHWORTH AS IN PA13617; S/T LT101251, LT108400; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR33	420930151	PCL 11339 SEC DKF; S PT LT 8 CON 6 SOUTHWORTH AS IN PA8410; EXCEPT LT33144 & LT 1 & 2 M494; S/T LT100950, LT45843; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR34	420930150	PCL 10978 SEC DKF; S1/2 LT 9 CON 6 SOUTHWORTH; S/T LT100740, LT45844; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR35	420930149	PCL 9337 SEC DKF SRO; N1/2 LT 9 CON 6 SOUTHWORTH; S/T LT100962, LT46501; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR36	420930148	PCL 25238 SEC DKF; N 1/2 LT 10 CON 6 SOUTHWORTH; S/T LT100962, LT46501; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR37	420900014	PCL 4719 SEC DKF SRO; PT LT 11 CON 1 HARTMAN AS IN PA3843; S/T LT105970, LT45834; DISTRICT OF KENORA	Crown	Yes	Permanent Easement	Offer Pending	[redacted]
DR38	420900013	PCL 4148 SEC DKF SRO; PT LT 11 CON 1 HARTMAN AS IN PA3437; S/T LT105970, LT45834; DISTRICT OF KENORA	Crown	Yes	Permanent Easement	Offer Pending	[redacted]
DR39	420900029	PCL 6460 SEC DKF SRO; S 1/2 LT 12 CON 2 HARTMAN; S/T LT105970, LT45829; DISTRICT OF KENORA	Crown	Yes	Permanent Easement	Offer Pending	[redacted]
DR40	420890692	PCL 9572 SEC DKF; S PT LT 2 CON 2 ZEALAND AS IN PA7292; S/T LT100951, LT45835; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR41	420890691	PCL 16865 SEC DKF; N PT LT 2 CON 2 ZEALAND AS IN PA12701; S/T LT101490, LT45923; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR42	420890245	PCL 14462 SEC DKF; PT BROKEN LT 2 CON 3 ZEALAND AS IN PA10767; S/T LT100952, LT45853; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR43	420890244	PCL 17905 SEC DKF; PT LT 3 CON 3 ZEALAND AS IN PA13287; S/T LT100739; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR44	420890243	PCL 13095 SEC DKF; W 1/2 LT 4 CON 3 ZEALAND; S/T LT101095, LT45922; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR45	420890785	SURFACE RIGHTS ONLY: N 1/2 LT 5 CON 3 ZEALAND; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR46	420890141	PCL 9922 SEC DKF; S1/2 LT 4 CON 4 ZEALAND; S/T LT103052, LT47194; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR47	420890137	PCL 7052 SEC DKF; S1/2 LT 5 CON 4 ZEALAND EXCEPT N1/2 OF S1/2; S/T LT103052, LT45852; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR48	420890138	PCL 15401 SEC DKF; N1/2 OF S1/2 LT 5 CON 4 ZEALAND; S/T LT101491, LT46143; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR49	420890134	PCL 15395 SEC DKF; S1/2 LT 6 CON 4 ZEALAND EXCEPT PT 1 & 3, 23R5468 SRO; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR50	420890140	PCL 40282 SEC DKF SRO; N1/2 LT 5 CON 4 ZEALAND; S/T LT100955, LT50894; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR51	420890082	PCL 20754 SEC DKF SRO; N1/2 LT 7 CON 4 ZEALAND; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR52	420890075	PCL 20469 SEC DKF; PT OF S1/2 OF LT 6 CON 5 ZEALAND AS IN PA14467; S/T LT105970; DISTRICT OF KENORA	Crown	Yes	Permanent Easement	Offer Pending	[redacted]
DR53	420890071	PCL 6611 SEC DKF; S1/2 LT 8 CON 5 ZEALAND; S/T LT105970; DISTRICT OF KENORA	Crown	Yes	Permanent Easement	Offer Pending	[redacted]
DR54	420890070	PCL 21358 SEC DKF; N PT BROKEN LT 9 CON 5 ZEALAND PT 1, 2 & 3, KR954; S/T LT105970, LT50893; DISTRICT OF KENORA	Crown	Yes	Permanent Easement	Offer Pending	[redacted]
DR55	420890037	PCL 18969 SEC DKF; PT LT 10 CON 6 ZEALAND AS IN LT51351 & LT41479: EXCEPT LT51424, LT51450, LT51568, LT52788, PT 1, 2, 3 & 4, 23R3991; PT 1, 2, 3, 4, 5, 6, 7, 23R9079; S/T LT51450, LT51568, LT52788, LT41479; S/T LT100954, LT45830; DRYDEN	Private	Yes	Permanent Easement	Offer Pending	[redacted]

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DR55B	420890050	PCL 30831 SEC DKF; PT LT 10 CON 6 ZEALAND PT 1, 2, 3, & 4, 23R3991;; S/T LT100954, LT45830; DRYDEN	Federal Government	Yes	Permanent Easement	Offer Pending	[redacted]
DR56	420890032	PCL 17285 SEC DKF; PT LT 11 CON 6 ZEALAND AS IN PA12946; LOCATION E.B.1193; EXCEPT PT 1 & 3, 23R3610; S/T PT2, 23R3610 AS IN LT117857; S/T LT101336, LT47125; DRYDEN	Private	Yes	Permanent Easement	Offer Pending	
DR57	420680055	PCL 17419 SEC DKF; S 1/2 LT 15 CON 7 ZEALAND; S/T LT102817, LT50892; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR58	420680056	PCL 17627 SEC DKF; S 1/2 OF N 1/2 LT 15 CON 7 ZEALAND; S/T LT102817, LT45870; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR59	420680101	PCL 24930 SEC DKF; E 1/2 OF N 1/2 LT 16 CON 7 ZEALAND; S/T LT102817, LT45833; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR60	420680019	PCL 9910 SEC DKF; W 1/2 OF N 1/2 LT 16 CON 7 ZEALAND; S/T LT100741, LT45842; DRYDEN	Private	Yes	Permanent Easement	Offer Pending	
DR61	420680029	PCL 11904 SEC DKF; N 1/2 LT 18 CON 7 ZEALAND EXCEPT PT 1 AND 2 KR883; S/T LT100956, LT45846; DRYDEN	Private	Yes	Permanent Easement	Offer Pending	
DR62	420680040	PCL 13545 SEC DKF; W1/2 OF S1/2 LT 19 CON 8 ZEALAND EXCEPT CANADIAN PACIFIC RAILWAY, LT74343, PT 2 23R4905, PT 1 AND 2 23R5296, S/T PT 3 23R5296 AS IN LT152648; S/T LT102814, LT45847; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR63	420680007	PCL 8000 SEC DKF; PT S 1/2 LT 19 CON 8 ZEALAND AS IN PA5931, EXCEPT PT 1 AND 5 KR717; DISTRICT OF KENORA SUBJECT TO AN EASEMENT IN GROSS OVER PTS 3, 6 & 8 23R2596 AS IN KN41538	Private	Yes	Permanent Easement	Offer Pending	
DR64	420680001	PCL 7668 SEC DKF; SE 1/4 OF S 1/2 LT 20 CON 8 ZEALAND EXCEPT PT 1 23R6264; DISTRICT OF KENORA SUBJECT TO AN EASEMENT IN GROSS OVER PTS 2, 7 & 9 23R2596 AS IN KN41538	Private	Yes	Permanent Easement	Offer Pending	
DR65	420680005	PCL 7686 SEC DKF; SW 1/4 OF S 1/2 LT 20 CON 8 ZEALAND BEING QUARRY CLAIM; DISTRICT OF KENORA SUBJECT TO AN EASEMENT IN GROSS OVER PTS 1 & 10 23R2596 AS IN KN41538	Private	Yes	Permanent Easement	Offer Pending	
DR66	420680002	PCL 7671 SEC DKF; SE 1/4 OF S 1/2 LT 21 CON 8 ZEALAND; DISTRICT OF KENORA SUBJECT TO AN EASEMENT IN GROSS OVER PTS 4 & 5 23R2589 AS IN KN41538	Private	Yes	Permanent Easement	Offer Pending	
DR67	420680058	PCL 17850 SEC DKF; LT 21 CON 8 ZEALAND BEING N 1/2 OF S 1/2 AND PT OF SW 1/4 OF S 1/2 AS IN PA13242. EXCEPT PT 1 23R4584; S/T LT101096; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR68	420680045	PCL 14716 SEC DKF; S 1/2 LT 22 CON 8 ZEALAND; S/T LT100953, LT45832; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR69	420680013	PCL 9322 SEC DKF; S 1/2 LT 23 CON 8 ZEALAND EXCEPT PT 1 M507; S/T LT102218, LT45845; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR70	420690188	PCL 5036 SEC DKF; S1/2 LT 1 CON 2 WAINWRIGHT EXCEPT LT76841 & PT 1, 23R3813; S/T LT100387, LT51738; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR71	420690184	PCL 3883 SEC DKF; PT LT 2 CON 2 WAINWRIGHT AS IN LT8220 EXCEPT LT76841; S/T LT113629, LT46399; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR72	420690177	PCL 29655 SEC DKF; PT LT 2 CON 2 WAINWRIGHT PT 1, 2 & 3, 23R3242 EXCEPT PT 1 & 2, 23R4197; S/T LT100386, LT48667; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR73	420690178	PCL 33862 SEC DKF; PT LT 2 CON 2 WAINWRIGHT PT 1, 23R5353; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR75	420690173	PCL 30891 SEC DKF; S PT BROKEN LT 3 CON 2 WAINWRIGHT PT 4, 5, 6, 7, 9, 10, 12 & 13, 23R4081; S/T LT100389, LT45848; DISTRICT OF KENORA SUBJECT TO AN EASEMENT IN GROSS AS IN KN58216	Private	Yes	Permanent Easement	Offer Pending	
DR76	420690172	PCL 33409 SEC DKF; S PT BROKEN LT 3 CON 2 WAINWRIGHT PT 1, 2, 3, 8 & 11, 23R4081; S/T LT100389, LT45848; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR77	420690471	PCL 27513 SEC DKF; PT S PT BROKEN LT 4 CON 2 WAINWRIGHT PT 4, 5 & 6, KR2097; S/T LT101415, LT45851; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR78	420690470	PCL 27485 SEC DKF; PT S PT BROKEN LT 4 CON 2 WAINWRIGHT PT 3, 7 & 8, KR2097; S/T LT100605, LT45851, LT47209, LT54265; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR79	420690468	PCL 27777 SEC DKF; PT S PT BROKEN LT 4 CON 2 WAINWRIGHT PT 1, 2 & 15, KR2097; S/T LT101414, LT45851, LT47209, LT54265; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	

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DR80	420690466	PCL 24329 SEC DKF; PT S PT OF N PT LT 4 CON 2 WAINWRIGHT PT 1 & 2, KR321; S/T LT47210; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	[redacted]
DR81	420690469	PCL 7102 SEC DKF; PT S PT BROKEN LT 4 CON 2 WAINWRIGHT AS IN PA5468 EXCEPT LT84544, PT 1, 2, 3, 4, 5, 6, 7, 8 & 15, KR2097; S/T LT45851, LT47209, LT54265; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR82	420690439	PCL 32200 SEC DKF; PT LT 5 CON 2 WAINWRIGHT BEING PT OF THE N 1/2 OF THE N 1/2 OF THE S 1/2 PT 1 & 2, 23R4543; S/T LT101338; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR83	420690443	PCL 25400 SEC DKF; PT S1/2 OF N1/2 LT 5 CON 2 WAINWRIGHT PT 1, 2, 3, 4 & 5, KR1023 EXCEPT LT84544 & PT 1 & 2, 23R5412; S/T LT154216, LT45662, LT63283; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR84	420690436	PCL 33051 SEC DKF; PT LT 5 CON 2 WAINWRIGHT BEING PT OF THE N 1/2 OF THE N 1/2 OF THE S 1/2 PT 1, 2, 3, 4, 5, 6 & 7, 23R5026 T/W PT 3, 23R3715 AS IN LT146969; S/T LT101338, LT153403, LT45663, LT63332; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
DR85	420690434	PCL 15435 SEC DKF; PT LT 5 CON 2 WAINWRIGHT BEING PT OF THE S 1/2 OF THE N 1/2 OF THE S 1/2 AS IN LT40707 EXCEPT LT84544, PT 1 & 2, 23R3715; S/T LT45886, LT54266, LT63353; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
	420690543	PCL 4477 SEC DKF; PT BROKEN LT 3 CON 2 WAINWRIGHT AS IN PA3681 EXCEPT PT 1 - 13, 23R4081; S/T LT100389; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
	420690601	PCL 18051 SEC DKF; PT LT 5 CON 2 WAINWRIGHT BEING THE N 1/2 OF THE N 1/2 OF THE S 1/2 EXCEPT LT84544, PT 3 & 4, 23R3715, PT 1, 2, 3 & 4, 23R4543 & PT 1, 2, 3, 4, 5, 6 & 7, 23R5026; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
	420690721	PCL 8218 SEC DKF; PT LT 4 CON 2 WAINWRIGHT AS IN PA6004; EXCEPT PT 1, 2 & 3, KR321, PT 1 & 2, KR672, LT84544, PLAN D5, PT 3, 7, 9 & 13, KR482 & PT 2, KR1727; DISTRICT OF KENORA	Private	Yes	Permanent Easement	Offer Pending	
				NO/LIMITED RIGHTS REQUIRED			
	420680105	PCL 25036 SEC DKF; FIRSTLY PT LT 20 CON 7 ZEALAND; SECONDLY PT LT 19 CON 8 ZEALAND; THIRDLY PT LT 19 CON 7 ZEALAND PT 1-5 KR717; PCL 43154 SEC DKF PT LT 20 CON 7 ZEALAND PT 1 TO 6 LT74343; DISTRICT OF KENORA	Crown	TBD	Potential Crossing Permit	N/A	
	420680227	PCL 43155 SEC DKF; PCL 32912 SEC DKF; PT W1/2 OF S1/2 LT 19 CON 8 ZEALAND PT 19 LT74343, PT 2 23R4905; PCL 13514 SEC DKF SRO; PCL 24114 SEC DKF SRO; PCL 24115 SEC DKF SRO; PCL 8437 SEC DKF; PT N PT & S PT LT 19 CON 7 ZEALAND PTS 20 TO 31 LT74343; S/T LT45	Crown	TBD	Potential Crossing Permit	N/A	
	420680241	PCL 24968 SEC DKF; PT LT 23 CON 8 ZEALAND PT 1 & 2 M507; DISTRICT OF KENORA	Crown	TBD	Potential Crossing Permit	N/A	
	420690426	PCL 30229 SEC DKF; PT S1/2 OF S1/2 LT 5 CON 2 WAINWRIGHT PT 1, 2 & 3, 23R3714; S/T LT271314; DISTRICT OF KENORA	Owned	No	Owned by Hydro One	N/A	
	420690433	PCL 23022 SEC DKF; PT S1/2 OF S1/2 LT 5 CON 2 WAINWRIGHT PT 1, 2, 3, 4, 5, 6, 7 & 8, KR244; S/T LT46662, LT54264, LT63247; DISTRICT OF KENORA	Owned	No	Owned by Hydro One	N/A	
	420690435	PCL 30230 SEC DKF; PT LT 5 CON 2 WAINWRIGHT BEING PT OF THE S 1/2 OF THE N 1/2 OF THE S 1/2 PT 1 & 2, 23R3715 S/T PT 1, 23R3715 AS IN LT118746; DISTRICT OF KENORA	Bill 58	No	Rights in Place (Bill 58)	N/A	
	420690566	PCL 24923 SEC DKF; PCL 43174 SEC DKF; PCL 23930 SEC DKF; PCL 23794 SEC DKF; PCL 24914 SEC DKF; PT LT 1 CON 2 WAINWRIGHT; PT LT 2 CON 2 WAINWRIGHT; PT LT 1 CON 3 WAINWRIGHT; PT LT 1 CON 4 WAINWRIGHT PT 1, 2, 3 & 5, LT77242, LT 1, 2 & 5, M499, LT 4, 5, 6, 7	Crown	TBD	Potential Crossing Permit	N/A	
	420690600	PCL 43218 SEC DKF; PCL 43242 SEC DKF; PCL 43037 SEC DKF; PCL 43241 SEC DKF; PCL 39111 SEC DKF; PT LT 5 CON 2 WAINWRIGHT PT 1, LT84776, PT 1, 8, 9, 10, 11, 13, 14, 15 & 16, LT84544 & PT 1, 23R8290; PCL 43239 SEC DKF; PT LT 5 CON 3 WAINWRIGHT PT 1, 2, 3, 4,	Crown	TBD	Potential Crossing Permit	N/A	
	420690605	PCL 26385 SEC DKF; UNIT 1 PL D5; PCL 43244 SEC DKF; PCL 24415 SEC DKF; PCL 43245 SEC DKF; PCL 23831 SEC DKF; PCL 43246 SEC DKF; PT BROKEN LT 4 CON 2 WAINWRIGHT PT 2, 3, 4, 5, 6, 7 & 12, LT84544 & PT 3, KR321; S/T LT47210; DISTRICT OF KENORA	Crown	TBD	Potential Crossing Permit	N/A	
	420690757	PT LT 2 CON 2 WAINWRIGHT PT 1 23R5414; DISTRICT OF KENORA	Crown	TBD	Potential Crossing Permit	N/A	

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	420930154	PCL 12373 SEC DKF; PT LT 7 CON 6 SOUTHWORTH AS IN LT33144; PCL 24861 SEC DKF; LT 1-4 PL M494; PCL 42849 SEC DKF PT OF S PT LT 8 CON 6 SOUTHWORTH AS IN LT33144; PCL 5034 SEC DKF PT N PT LT 8 CON 6 SOUTHWORTH AS IN LT33144; PCL 24862 SEC DKF SRO PT 1 & 2, P	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	420930200	PCL 17499 SEC DKF; PT S1/2 LT 1 CON 2 SOUTHWORTH AS IN LT47207; DISTRICT OF KENORA	Bill 58	No	Rights in Place (Bill 58)	N/A	
	420930372	PCL 10840 SEC DKF; PCL 42804 SEC DKF; PT N PT LT 6 CON 4 SOUTHWORTH; S PT LT 6 CON 5 SOUTHWORTH AS IN LT32338; DISTRICT OF KENORA	Crown	TBD	Potential Crossing Permit	N/A	
	420950041	PCL 5704 SEC DKF THE RIGHT OF WAY OF THE DYMENT BRANCH OF THE CANADIAN PACIFIC RAILWAY ACROSS; PT LT 6 CON 2 MELGUND; PT LT 5 CON 4 MELGUND; PT LT 6 CON 1 MELGUND; PT LT 4 CON 4 MELGUND; PT LT 4 CON 5 MELGUND; PT LT 5 CON 3 MELGUND; PT LT 7 CON 1 MELGUND;	Railway Crossing	No	Crossing Permit	N/A	
	420980008	PCL 42062 SEC DKF; PT UNSUBDIVIDED PORTION HODGSON PT 1 MISC 864, PT 2 MISC 864 BEING PT OF THE BED OF AN UNNAMED LAKE, PT 1 MISC 865, PT 1 MISC 866, PT 1 MISC 867; DISTRICT OF KENORA	Crown	TBD	Potential Crossing Permit	N/A	
	560051203	PCL 16858 SEC RAINY RIVER SURFACE RIGHT ONLY; PT MINING LOCATION G-324 SCHWENGER; PT MINING LOCATION 815-X SCHWENGER; PT MINING LOCATION 816-X SCHWENGER; PT MINING LOCATION 817-X SCHWENGER; PT MINING LOCATION 818-X SCHWENGER; PT MINING LOCATION 871-X SCHW	Crown	TBD	Potential Crossing Permit	N/A	
	560052029	PCL 19317 SEC RAINY RIVER; PT LOCATION SH 279 SCHWENGER PT 1, 48R1871, T/W PT 2, 48R1735 AS IN A25109; ATIKOKAN	Private	TBD	Potential Crossing Permit	N/A	
	560052050	PCL 19317 SEC RAINY RIVER; PT CROWN LANDS SCHWENGER PT 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, & 13, RR378, T/W PT 2, 48R1735 AS IN A25109; ATIKOKAN	Private	TBD	Potential Crossing Permit	N/A	
	560052274	PCL 26027 SEC RAINY RIVER; PT MINING LOCATION 816X PT 3, 48R3737, SURFACE RIGHTS ONLY; ATIKOKAN	Crown	TBD	Potential Crossing Permit	N/A	
	560660994	PCL 16439 SEC RAINY RIVER; MINING CLAIM F.F. 5760 UNSURVEYED TERRITORY EXCEPTING THEREOUT ALL DEPOSITS OF SAND & GRAVEL TOGETHER WITH THE RIGHT OF THE CROWN OR ITS DESIGNATES T ENTER & REMOVE SAME WITHOUT COMPENSATION; DISTRICT OF RAINY RIVER	Owned	No	Owned by Hydro One	N/A	
	560660997	PCL 16442 SEC RAINY RIVER; MINING CLAIM F.F. 5939 UNSURVEYED TERRITORY LAND & LAND UNDER THE WATER OF A SMALL UNNAMED CREEK WITHIN THE LIMITS OF THIS MINING CLAIM EXCEPT SURFACE RIGHTS OF PT 6 & 7 48R1368 & ALL PT 1 48R1562 & PT 2 48R2612 S/T PT 4 48R1867	Owned	No	Owned by Hydro One	N/A	
	560661616	PCL 21989 SEC RAINY RIVER SURFACE RIGHTS ONLY; FIRSTLY PT MINING CLAIM F.F. 5763 UNSURVEYED TERRITORY PT 4, 48R1368; SECONDLY PT MINING CLAIM FF. 5759 UNSURVEYED TERRITORY PT 5, 48R1368; THIRDLY PT MINING CLAIM FF.5939 UNSURVEYED TERRITORY PT 6 & 7 48R136	Crown	TBD	Potential Crossing Permit	N/A	
	560661913	PCL 23221 SEC RAINY RIVER; FIRSTLY PT MINING CLAIM FF 5275 UNSURVEYED TERRITORY PT 1, 48R1867; SECONDLY PT MINING CLAIM FF 5274 UNSURVEYED TERRITORY PT 2 & 6, 48R1867, S/T PT 6, 48R1867 AS IN A24977; DISTRICT OF RAINY RIVER	Bill 58	No	Rights in Place (Bill 58)	N/A	
	560662988	PCL 2066 SEC RAINY RIVER; CNR RIGHT OF WAY UNSURVEYED TERRITORY /FREEBORN; RIGHT OF WAY FROM THE EASTERN BOUNDARY OF THE DISTRICT OF RAINY RIVER, W TO MINING LOCATION 636X TWP OF HUTCHINSON BEING 237.60 ACRES; ABIWIN STATION GROUNDS BEING 9.23 ACRES; KAWE	Railway Crossing	No	Crossing Permit	N/A	
	560663066	PCL L728 SEC RAINY RIVER LEASEHOLD; PT LOCATION SH-159 MCCAUL PT 3, RR363; DISTRICT OF RAINY RIVER	Bill 58	No	Rights in Place (Bill 58)	N/A	
	560663380	PARCEL 14893 SEC RAINY RIVER; MINING CLAIM F.F.5274 UNSURVEYED TERRITORY EXCEPT SLT70462 & PARTS 8 & 9, 48R1867; S/T EASEMENT OVER PART 5, 48R1867 AS IN A24978; DISTRICT OF RAINY RIVER	Bill 58	No	Rights in Place (Bill 58)	N/A	
	623130403	PCL 4611 SEC DFWF; PT MINING CLAIM TB 39172 HAGEY AS IN LEW22202 & LEW22997; DISTRICT OF THUNDER BAY	Crown	TBD	Potential Crossing Permit	N/A	
	623180111	PCL 19333 SEC TBF; PT S 1/2 LT 13 CON 1 FORBES PT 2 55R4397, PT 2 55R5268; DISTRICT OF THUNDER BAY	Crown	TBD	Potential Crossing Permit	N/A	
	623190175	RDAL BTN LT 42 & LT 43 CON 1 DAWSON ROAD LOTS; DISTRICT OF THUNDER BAY	Road Allowance	No	Rely on S.41(1) of the Electricity Act	N/A	

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	623190177	RDAL BTN LT 37 & LT 38 CON 1 DAWSON ROAD LOTS; DISTRICT OF THUNDER BAY	Road Allowance	No	Rely on S.41(1) of the Electricity Act	N/A	[redacted]
	623190178	RDAL BTN LT 32 & LT 33 CON 2 DAWSON ROAD LOTS; DISTRICT OF THUNDER BAY	Road Allowance	No	Rely on S.41(1) of the Electricity Act	N/A	[redacted]
	623190180	RDAL BTN LT 27 & LT 28 CON 2 DAWSON ROAD LOTS; DISTRICT OF THUNDER BAY	Road Allowance	No	Rely on S.41(1) of the Electricity Act	N/A	[redacted]
	623190182	RDAL BTN LT 22 & LT 23 CON 2 DAWSON ROAD LOTS; DISTRICT OF THUNDER BAY	Road Allowance	No	Rely on S.41(1) of the Electricity Act	N/A	[redacted]
	623190184	RDAL BTN LT 17 & LT 18 CON 2 DAWSON ROAD LOTS; DISTRICT OF THUNDER BAY	Road Allowance	No	Rely on S.41(1) of the Electricity Act	N/A	[redacted]
	623190201	RDAL BTN CON 1 & CON 2 DAWSON ROAD LOTS BTN SLY EXT OF E LIMIT LT 1 CON 2 & SLY EXT OF W LIMIT LT 49 CON 2; DISTRICT OF THUNDER BAY	Road Allowance	No	Rely on S.41(1) of the Electricity Act	N/A	[redacted]
	623210155	PCL 25075 SEC TBF; PT LT 14 CON 3 WARE PT 4 55R9332 BEING A TRAVELLED RD DESIGNATED AS A LOCAL RD IN THE WARE ROADS AREA; DISTRICT OF THUNDER BAY	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	623210171	PCL 23548 SEC TBF; PT S 1/2 LT 11 CON 3 WARE PT 3 55R7742 BEING TRAVELLED RD DESIGNATED AS A LOCAL RD IN THE WARE LOCAL ROADS AREA; DISTRICT OF THUNDER BAY	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	623220286	PCL 19333 SEC TBF; PT S PT LT 10 CON 3 WARE PT 1, 2 & 3 55R5186, PT 6 55R4731; DISTRICT OF THUNDER BAY	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	623220478	PCL 25428 SEC TBF; PT N 1/2 LT 2 CON 2 WARE PT 1, 2, 4 & 8 55R9799 BEING A TRAVELLED RD; DISTRICT OF THUNDER BAY	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	623240042	PCL 18389 SEC TBF; PT LT 18 CON 2 GORHAM PT 5 55R3320; DISTRICT OF THUNDER BAY	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	623240155	PCL 19083 SEC TBF; PT S PT BROKEN LT 14 CON 2 GORHAM PT 1 TO 3 55R3926; S/T LPA83919; DISTRICT OF THUNDER BAY	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	623240326	PCL 14640 SEC TBF; UNIT 1 D-15 GORHAM; UNIT 2 D-15 GORHAM; UNIT 3 D-15 GORHAM; DISTRICT OF THUNDER BAY	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	623240417	PCL 3391 SEC TBF; PT S 1/2 LT 14 CON 1 GORHAM AS IN LPA65423; PCL 26877 SEC TBF ; PT S 1/2 LT 14 CON 1 GORHAM AS IN LPA64135 (AMENDED BY LPA65983) & LPA65983; PCL 4555 SEC TBF; PT LT 15 CON 1 GORHAM BEING PT E 1/2 OF S 1/2 AS IN LPA65423 (AMENDED BY LPA65	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	623250324	PCL STREETS-1 SEC M56; ROADS PL M56 GORHAM; DISTRICT OF THUNDER BAY	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	623250353	PCL 26616 SEC TBF; PT SE 1/4 MINING LOCATION N. 8 GORHAM PT 5, 7 55R10830, BEING A TRAVELLED RD; DISTRICT OF THUNDER BAY	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	624960698	PT MINING LOCATION 7-E WHITE'S SURVEY MACGREGOR PT 8 55R13175 MUNICIPALITY OF SHUNIAH	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	624960699	SRO PT MINING LOCATION 7-E WHITE'S SURVEY MACGREGOR PT 2 PAR356 EXCEPT PT 8 55R13175 TOGETHER WITH AN EASEMENT OVER PT LT 3 CON 7 DORION PTS 4, 5, 9 & 10 ON 55R13119 UNTIL 2031/12/12 AS IN TY113135 SUBJECT TO AN EASEMENT IN GROSS OVER PT 1 55R14720 AS IN	Owned	No	Owned by Hydro One	N/A	[redacted]
	625050823	PCL 7812 SEC DFWF; PT MINING LOCATION 70 Z UNSURVEYED TERRITORY; PT MINING LOCATION AL 641 UNSURVEYED TERRITORY AS IN LEW49214; S/T LEW14559, LEW14653, LEW25029, LEW25106, LT94958; DISTRICT OF THUNDER BAY	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	625051129	PT MINING LOCATION 71Z BETWEEN LAKE SHEBANDOWAN & LAKE KASHABOWIE UNSURVEYED TERRITORY AS IN OFW42564 ; AKA HWY 802 & BURCHELL LAKE RD; S/T RUS2227, RUS2334; DISTRICT OF THUNDER BAY	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	625051134	PT MINING LOCATION 71Z BETWEEN LAKE SHEBANDOWAN & LAKE KASHABOWIE UNSURVEYED TERRITORY; PT MINING LOCATION K 56 SHEBANDOWAN LAKE (C. C. FORNERIS SURVEY) UNSURVEYED TERRITORY AS IN RUS2314 EXCEPT PT 1, RR47 AKA HWY 11; DISTRICT OF THUNDER BAY	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	625060266	PT MINING LOCATION 5 SAVIGNY'S SURVEY MACGREGOR PT 11, PAR2R; PT MINING LOCATION 23Z MILES SURVEY MACGREGOR PT 12, PAR2R , PT 3, 55R9477 SRO; PT MINING LOCATION 24Z MILES SURVEY MACGREGOR PT 13, PAR2R , PT 1, 2, 55R9477, PT 7, 55R2635, PT 2, 3, 4, 55R2635	Crown	TBD	Potential Crossing Permit	N/A	[redacted]

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	625060309	PT MINING LOCATION 1 H. P. SAVIGNY'S SURVEY MACGREGOR AS IN PT 2, PTA119942 , PT 5, 7, 55R9702 SRO, PT 2, 3, TBR362073 SRO; PT MINING LOCATION 2 H. P. SAVIGNY'S SURVEY MACGREGOR AS IN PT 3, PTA119942 , PT 1, PTA120776, PT 4 55R9702 SRO, PT 1 TBR362073 SRO	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	625060448	PT MINING LOCATION 2 H. P. SAVIGNY'S SURVEY MACGREGOR PT 1, 55R13118; PT MINING LOCATION 3 H. P. SAVIGNY'S SURVEY MACGREGOR PTS 3, 4, 5, 55R13118 EXCEPT MINING RIGHTS AS IN TBR155740 SUBJECT TO AN EASEMENT AS IN PTA131136 SUBJECT TO AN EASEMENT AS IN TBR3	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	625060451	PT MINING LOCATION 6E WHITE'S SURVEY MACGREGOR SRO, PT 6 55R13175; SHUNIAH	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	625060455	PT MINING LOCATION 3 H. P. SAVIGNY'S SURVEY MACGREGOR, PT 4 55R13175; PT MINING LOCATION 4 SAVIGNY'S SURVEY MACGREGOR SRO, PT 5 55R13175; MUNICIPALITY OF SHUNIAH	Crown	TBD	Potential Crossing Permit	N/A	[redacted]
	625060457	PT MINING LOCATION 3 SAVIGNEY'S SURVEY MACGREGOR PT 6 55R13118 MUNICIPALITY OF SHUNIAH	Crown	TBD	Potential Crossing Permit	N/A	[redacted]

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PHASE 1								
WTL18255	100777	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18257	106108	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18258	106205	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18261	108364	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18264	112582	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18265	114228	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18266	114229	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18267	114272	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18268	114273	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18280	125498	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18283	134771	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18285	136429	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18287	137482	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18291	140500	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18296	144284	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18298	145733	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18301	147476	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18310	159993	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18311	159994	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18314	161392	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18315	163390	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18319	166668	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18328	176717	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18332	179401	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18333	186765	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19381	188239	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18338	189059	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18341	193654	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18342	193655	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18343	193861	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18346	194598	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18348	195451	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18350	198857	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18354	201273	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18355	202676	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18356	203212	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19382	207768	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18368	213984	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18370	215391	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18380	221632	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18382	224707	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18391	237184	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18392	237575	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18393	237893	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18397	241025	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18405	248701	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18406	249080	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18409	249837	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18412	253479	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18413	257407	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18414	258748	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18418	261803	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19383	267045	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18422	267845	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18424	268580	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18435	274459	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18461	302774	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18465	304267	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18466	304971	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18467	305083	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18469	306492	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18478	311213	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18479	311879	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18481	312197	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18487	314535	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18499	328438	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18500	328508	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18506	332005	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18511	334326	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18512	334514	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18516	338286	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]

	Property Identification	LEGAL DESCRIPTION	TYPE OF PROPERTY (Municipal, Private, Etc.)	PROPERTY CLASSIFICATION	Does Hydro One Require New or Updated Property Rights	RIGHTS REQUIRED	Where Agreement is Outstanding - Summary of Negotiations to Date	Owner(s)
WTL18518	340934	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18521	345018	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18588	534191	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18590	534211	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18594	534231	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18596	534234	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18598	534240	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18599	534242	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18600	534243	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18601	534244	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18603	534249	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18604	534250	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18605	534251	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18606	534253	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18607	534254	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18608	534257	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18609	534258	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18610	534259	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18611	534261	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18612	534264	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18614	534266	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18615	534267	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18616	534268	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18621	536292	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18623	536296	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18624	536298	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18625	536299	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18626	536302	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18629	536307	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18630	536309	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18631	536311	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18633	536315	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18635	536321	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18636	536325	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18637	536335	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18638	536336	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18639	536337	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18642	536357	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18647	536377	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18648	536378	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18649	536380	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18652	536386	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18654	546228	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18655	546229	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18656	546230	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18657	546231	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18658	546232	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18659	546235	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18660	546236	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18661	546237	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18662	546238	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18663	546239	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18664	546243	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18666	555290	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18667	555291	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18668	555292	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18670	561653	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18671	561654	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18672	561655	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18673	561656	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18674	561657	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18680	598944	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18682	598946	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18683	598948	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18684	598950	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18685	598953	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18687	598958	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18688	598960	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18689	598961	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18690	598962	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18691	605309	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18692	605310	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18695	605314	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	
WTL18697	605317	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	

	Property Identification	LEGAL DESCRIPTION	TYPE OF PROPERTY (Municipal, Private, Etc.)	PROPERTY CLASSIFICATION	Does Hydro One Require New or Updated Property Rights	RIGHTS REQUIRED	Where Agreement is Outstanding - Summary of Negotiations to Date	Owner(s)
WTL18698	605318	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18699	605319	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18700	605320	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18701	605322	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18704	605350	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18705	605352	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18706	605355	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18707	621532	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18708	621533	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18709	621750	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19334	626074	Unorganized Crown Lands	Provincial Crown	Active Authorized Aggregate Site	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19331	626125	Unorganized Crown Lands	Provincial Crown	Active Authorized Aggregate Site	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19333	626132	Unorganized Crown Lands	Provincial Crown	Active Authorized Aggregate Site	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19319	626136	Unorganized Crown Lands	Provincial Crown	Active Authorized Aggregate Site	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18747	657277	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18972	681346	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18111	69712180	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Licence of Occupation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19075	701807	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19076	701808	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19077	701809	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19078	701812	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19079	701813	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19080	701814	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19081	701816	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19082	701819	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19083	701821	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19084	701823	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19085	701827	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19086	701833	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19087	701839	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19088	701841	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19090	701847	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19091	701848	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19096	701869	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19097	701876	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19105	701917	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19109	721913	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19114	722267	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19115	722268	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19116	722269	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19117	722603	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19119	725785	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19122	726759	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19123	726760	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19125	726807	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19126	726808	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19127	726809	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19128	726810	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19130	731649	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19156	737185	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19163	737199	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19164	737200	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19166	737207	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19167	737208	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19168	737210	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19169	737212	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19170	737213	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19173	737221	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19175	737224	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19177	737229	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19179	737231	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19185	737291	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19188	737296	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19194	737311	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19203	740249	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19204	740269	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19205	740271	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19210	740290	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19211	740292	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19212	740293	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19216	740302	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19219	740318	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19233	740457	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]

	Property Identification	LEGAL DESCRIPTION	TYPE OF PROPERTY (Municipal, Private, Etc.)	PROPERTY CLASSIFICATION	Does Hydro One Require New or Updated Property Rights	RIGHTS REQUIRED	Where Agreement is Outstanding - Summary of Negotiations to Date	Owner(s)
WTL19235	740464	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19396	807916	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19397	807920	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19398	807921	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19395	807922	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19399	807936	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19400	807944	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19385	810575	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19388	810576	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19389	811115	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19390	811116	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19391	811117	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19403	829179	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19432	841681	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19433	841682	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19434	841684	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19435	842482	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19436	842483	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19378	MTO AP 500 226	Unorganized Crown Lands	Provincial Crown	MTO Aggregate Site	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19379	MTO AP 500 283	Unorganized Crown Lands	Provincial Crown	MTO Aggregate Site	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19380	MTO AP 500 425	Unorganized Crown Lands	Provincial Crown	MTO Aggregate Site	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19338	P-3091-18	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19335	See ALPS 500425	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19366	SURFACE RIGHTS RESERVATION #F188542	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19351	WNCR-9/83	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19347	W-TB-124/09	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19365	W-TB-30/93	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19341	W-TB-31/13	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19358	W-TB-49/15	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19359	wtb69-16	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19302	623130146	PCL 4611 SEC DFWF; PT MINING CLAIM TB 39172 HAGEY AS IN LT101990 & PT 13 FWR360 EXCEPT LEW22202 & LEW22997; S/T LEW49450; DISTRICT OF THUNDER BAY	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19301	623130147	PCL 4609 SEC DFWF; PT MINING CLAIM TB 40058 HAGEY AS IN LT101989 & PT 10 55R360; S/T LEW49450; DISTRICT OF THUNDER BAY	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19303	623130148	PCL 4610 SEC DFWF; PT MINING CLAIM TB 39173 HAGEY AS IN LT101988 & PT 9 FWR360; S/T LEW49450; DISTRICT OF THUNDER BAY	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19307	623170040	MINING RIGHTS ONLY PT OF S PT LT 12 CON 2 GOLDIE AS IN LT95000; S/T LEW45805; DISTRICT OF THUNDER BAY;	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19306	623190762	PCL 1958 SEC DFWF; LT 74 CON B DAWSON ROAD LOTS EXCEPT SRO AS IN LT174560; S/T LEW46270; DISTRICT OF THUNDER BAY	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19308	623210210	PCL 25429 SEC TBF; LOCATION CL 7060 WARE PT 1 55R7156; DISTRICT OF THUNDER BAY	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19309	624960482	MINING LOCATION 10E H. WHITE SURVEY MACGREGOR; MINING LOCATION 7E H. WHITE SURVEY MACGREGOR; MINING LOCATION 8E H. WHITE SURVEY MACGREGOR; MINING LOCATION 9E H. WHITE SURVEY MACGREGOR N OF CPR EXCEPT SRO; SHUNIAH	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19305	625050550	PCL 4578 SEC DFWF; MINING CLAIM TB 39176 UNSURVEYED TERRITORY BEING LAND AND LAND COVERED WITH THE WATER OF PT OF AN UNNAMED LAKE WITHIN THE LIMITS OF THIS MINING CLAIM, SITUATE IN THE UPPER SHEBANDOWAN LAKE AREA, SAVING AND EXCEPTING THEREOUT AND THEREFROM THE SRO ON AND OVER THE TRANSMISSION LINE OF THE HYDRO-ELECTRIC POWER COMMISSION CROSSING THE SAID CLAIM, EXCEPT LEW24011, LEW35047, LEW35005; S/T LEW27075, LEW45773; DISTRICT OF THUNDER BAY	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19304	625050551	PCL 4579 SEC DFWF; MINING CLAIM TB 39177 UNSURVEYED TERRITORY BEING LAND AND LAND COVERED WITH THE WATER OF PT OF AN UNNAMED LAKE WITHIN THE LIMITS OF THIS MINING CLAIM, SITUATE IN THE UPPER SHEBANDOWAN LAKE AREA, SAVING AND EXCEPTING THEREOUT AND THEREFROM THE SRO ON AND OVER THE ROW OF THE TRANSMISSION LINE OF THE HYDRO-ELECTRIC POWER COMMISSION CROSSING THE SAID CLAIM, EXCEPT LEW24011; S/T LEW27075, LEW45773; DISTRICT OF THUNDER BAY	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]

	Property Identification	LEGAL DESCRIPTION	TYPE OF PROPERTY (Municipal, Private, Etc.)	PROPERTY CLASSIFICATION	Does Hydro One Require New or Updated Property Rights	RIGHTS REQUIRED	Where Agreement is Outstanding - Summary of Negotiations to Date	Owner(s)
WTL19310	625050591	PCL 2211 SEC DFWF; MINING LOCATION AL 641 UNSURVEYED TERRITORY SITUATE ON THE W SIDE OF KASHABOIWE RIVER, N OF LAKE SHEBANDOWAN, EXCEPT SRO ON AND OVER A STRIP OF LAND ONE CHAIN IN PERPENDICULAR WIDTH ALONG THE SHORE OF KASHABOIWE RIVER, AND EXCEPT THE ROW AND LANDS OF THE CANADIAN NATIONAL RAILWAY, AND EXCEPT LEW49214; S/T LEW14559, LEW25106, LEW47169; DISTRICT OF THUNDER BAY	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18217	70321644	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Crown Easement	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18218	70321903	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Crown Easement	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
				PHASE 2				
WTL19299	420890134	PCL 15395 SEC DKF; S1/2 LT 6 CON 4 ZEALAND EXCEPT PT 1 & 3, 23R5468 SRO; DISTRICT OF KENORA	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19290	420890139	PCL 17395 SEC DKF MRO; N1/2 LT 5 CON 4 ZEALAND; S/T LT100955, LT50894; DISTRICT OF KENORA	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19298	420890784	MINING RIGHTS ONLY; N 1/2 LT 5 CON 3 ZEALAND; DISTRICT OF KENORA	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19288	420890804	MINING RIGHTS ONLY: ALL THAT LAND AND LAND UNDER WATER, BEING N 1/2 LT 7 CON 4 ZEALAND CONTAINING 63.940 HECTARES, MORE OR LESS, COMPRISING ALL OF	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19289	420890820	LAND AND LAND UNDER WATER PART NORTH HALF LOT 6 CON 4 ZEALAND BEING MINING CLAIM K1119532 AND PART MINING CLAIMS K1119537,K1119531, AND K1119538 BEING PART 3 23R12396; UNORGANIZED TERRITORIES	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19291	420950148	PCL 40411 SEC DKF; PT LT 1 CON 4 MELGUND BEING; LOCATION CL7611 MELGUND PT 1, 23R7495; DISTRICT OF KENORA	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19295	420960020	PCL 40412 SEC DKF; PT LOCATION CL7620 REVELL PT 2, 23R7677; DISTRICT OF KENORA	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19296	420960024	PCL 40411 SEC DKF; PT LOCATION CL7615 REVELL PT 3, 23R7597; DISTRICT OF KENORA	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19294	420960028	PCL 40411 SEC DKF; LOCATION CL7619 REVELL PT 1 & 2, 23R7634; DISTRICT OF KENORA	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19297	420960033	PCL 40412 SEC DKF; PT LOCATION CL7620 REVELL PT 3, 23R7677; DISTRICT OF KENORA	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL17970	69773196	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Crown Easement	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL17966	69773236	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Crown Easement	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18254	100099	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18256	101335	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18260	107331	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18262	111148	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19322	11151	Unorganized Crown Lands	Provincial Crown	Active Authorized Aggregate Site	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19324	11467	Unorganized Crown Lands	Provincial Crown	Active Authorized Aggregate Site	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18269	115735	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18270	116189	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18271	116190	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18272	116252	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18275	117151	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL17837	69824584	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Lease	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL17742	70308401	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Crown Easement	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL17770	70308406	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Crown Easement	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18288	139469	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18289	139470	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18304	152296	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18313	160968	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18320	167080	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18337	188016	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18347	194877	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19316	20301	Unorganized Crown Lands	Provincial Crown	Active Authorized Aggregate Site	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18362	206228	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18363	206229	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18369	214922	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18373	215736	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18383	225528	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18384	225529	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18387	233867	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18403	247620	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18421	266792	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]

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WTL18428	268968	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18430	270918	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18431	271202	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18433	274210	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18434	274292	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18436	277517	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18441	281841	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18443	283009	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18448	286761	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18449	286762	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18451	286872	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18453	293697	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18460	301103	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18462	302921	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18501	331157	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18507	332658	Unorganized Crown Lands	Provincial Crown	Boundary Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18508	332659	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18513	335072	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18520	343450	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19285	420990019	SURFACE RIGHTS ONLY PCL 3012 SEC DKL; PT LOCATION SN120 ILSLEY PT 1, 2 & 3 23R5973; DISTRICT OF KENORA	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19292	560052050	CL 19317 SEC RAINY RIVER; PT CROWN LANDS SCHWENGER PT 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, & 13, RR378, T/W PT 2, 48R1735 AS IN A25109; ATIKOKAN	Provincial Crown	Limited Interest/Leasehold	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18539	532446	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18545	532466	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18547	532472	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18548	532473	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18549	532474	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18550	532475	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18564	532514	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18566	532522	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18567	532523	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18569	532530	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18570	532531	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18573	532536	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18574	532537	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18575	532538	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19325	600941	Unorganized Crown Lands	Provincial Crown	Active Authorized Aggregate Site	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19315	604362	Unorganized Crown Lands	Provincial Crown	Active Authorized Aggregate Site	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18745	655275	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18746	655276	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18758	670664	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18766	670696	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18767	670697	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18769	670700	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18770	670706	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18771	670707	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18773	670714	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18775	670719	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18776	670721	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18777	670726	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18778	670727	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18780	670756	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18781	670757	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18783	670761	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18784	670762	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18787	670766	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18788	670767	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18857	671028	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18858	671029	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18859	671050	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18860	671051	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18861	671061	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18862	671062	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18864	671064	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]

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WTL18867	671070	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18890	671145	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18892	671155	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18893	671156	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18895	671159	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18902	671172	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18905	671396	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18906	671397	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18907	671398	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18908	671399	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18909	671401	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18910	671402	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18911	671403	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18912	671405	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18913	671406	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18914	672056	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18919	672067	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18929	672095	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18930	672098	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18933	672110	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18967	680807	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18968	680808	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18969	680816	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18975	681352	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18976	681353	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18977	681354	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18979	681360	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18982	681366	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18983	681367	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18984	681375	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18985	681376	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL18996	681647	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19002	681670	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19004	681674	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19005	681675	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19006	681676	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19008	681836	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19010	681848	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19011	681849	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19012	681850	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19014	681859	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19045	683081	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19047	687216	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19048	687217	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19050	688334	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19051	688335	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19052	688342	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19053	688345	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19055	688358	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19056	688359	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19057	688362	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19058	688363	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19059	688367	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL17758	70308409	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Crown Easement	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL17769	70308536	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Crown Easement	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL17760	70308553	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Crown Easement	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19062	700031	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19063	700280	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19064	700281	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19065	700282	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19071	700966	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19107	702788	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL17747	70327477	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Crown Easement	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL17751	70327478	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Crown Easement	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL17741	70340797	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Crown Easement	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]

	Property Identification	LEGAL DESCRIPTION	TYPE OF PROPERTY (Municipal, Private, Etc.)	PROPERTY CLASSIFICATION	Does Hydro One Require New or Updated Property Rights	RIGHTS REQUIRED	Where Agreement is Outstanding - Summary of Negotiations to Date	Owner(s)
WTL17771	70340810	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Crown Easement	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL17757	70340814	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Crown Easement	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL17626	120017229	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Lease	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL17628	124223691	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - Lease	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL17711	128815117	Unorganized Crown Lands	Provincial Crown	Non Freehold Disposition - LUP	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19129	731608	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19154	733682	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19241	743798	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19242	743799	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19243	743800	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19244	745666	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19384	745669	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19251	752828	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19266	759033	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19267	759035	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19268	759040	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19269	759041	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19270	759043	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19271	759052	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19283	799886	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19284	799887	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19414	805580	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19415	805597	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19416	805605	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19401	805620	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19402	805621	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19417	821433	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19418	821434	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19419	821439	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19420	821445	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19421	821452	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19422	821453	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19423	821460	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19404	821821	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19405	821824	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19406	821828	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19407	821830	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19408	821831	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19409	821834	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19410	821839	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19411	821845	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19412	821846	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19413	821853	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19392	823793	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19393	823796	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19394	823797	Unorganized Crown Lands	Provincial Crown	Multi-cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19424	828496	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19425	828524	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19426	828527	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19427	828528	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19428	828530	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19429	828531	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19430	828551	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19431	828608	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19386	834750	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19387	834751	Unorganized Crown Lands	Provincial Crown	Single Cell Mining Claim	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19374	MTO AP 500 070	Unorganized Crown Lands	Provincial Crown	MTO Aggregate Site	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19375	MTO AP 500 434	Unorganized Crown Lands	Provincial Crown	MTO Aggregate Site	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19349	SEC.43 MG ACT W21/80	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19339	W6/80	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19363	W-73/83	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19372	wk26-17	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19345	W-K-37/01	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19362	wk60-15	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19343	W-K-98/13	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19336	W-TB-24/04	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]
WTL19353	W-TB-33/94	Unorganized Crown Lands	Provincial Crown	Operational Alienation	Yes	Stakeholder Consent	Offer to Consent Pending	[redacted]

MINISTRY OF NORTHERN DEVELOPMENT AND MINES DELEGATION LETTER OCTOBER 25, 2018

Ministry of Energy, Northern Development and Mines

Office of the Deputy Minister of Energy

Hearst Block, 4th Floor
900 Bay Street
Toronto, ON M7A 2E1
Tel: 416-327-6758
Fax: 416-327-6755

Ministère de l'Énergie, du Développement du Nord et des Mines

Bureau du sous-ministre de l'Énergie

Édifice Hearst, 4e étage
900, rue Bay
Toronto, ON M7A 2E1
Tél. : 416-327-6758
Téléc. : 416-327-6755

Ontario

October 25, 2018

Christine Goulais
Senior Manager, Indigenous Relations
Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario M5G 2P5

Indigenous Energy Policy

VIA EMAIL

Re: Northwest Bulk Transmission Line

Dear Christine Goulais:

Thank you for your letter dated November 13, 2017 requesting clarification from the Ministry of Energy, Northern Development and Mines on the Duty to Consult requirements for the Northwest Bulk Transmission Line Project according to the updated scope of the 2017 Long Term Energy Plan.

Your letter states that the preliminary scope of the project consists of a new double-circuit 230 kilovolt line between Lakehead Transmission Station (TS) within the Municipality of Shuniah and Mackenzie TS within the Township of Atikokan, and a new single-circuit 230 kilovolt line from Mackenzie TS within the Township of Atikokan to Dryden TS within the City of Dryden.

The Ministry of Energy, Northern Development and Mines has reviewed the information provided relative to its current understanding of the interests of First Nation and Métis communities in the area and has determined that it may have the potential to affect First Nation and Métis communities who hold or claim Aboriginal or treaty rights protected under Section 35 of Canada's *Constitution Act* 1982.

The Ministry of Energy, Northern Development and Mines is delegating the procedural aspects of consultation to Hydro One Networks Inc. (Hydro One). The Ministry of Energy, Northern Development and Mines expects that Hydro One will undertake the procedural aspects of consultation for the updated Northwest Bulk Transmission Line Project, consistent with the responsibilities outlined in the Memorandum of Understanding (MOU) signed between Ontario, represented by the (former) Minister of Energy, and Hydro One, in September 2016.

Based on the Crown's assessment of First Nation and Métis community rights and project impacts, the following Aboriginal communities should be consulted on the basis that they have or may have constitutionally protected Aboriginal or treaty rights that may be adversely affected by the Project:

Community	Mailing Address
Eagle Lake First Nation*	Eagle Lake First Nation PO Box 1001 Migisi Sahgaigan, ON P0V 3H0
Fort William First Nation	Fort William First Nation 90 Anemki Place, Suite 200 Fort William First Nation, ON P7J 1L3
Nigigoonsiminikaaning First Nation*	Nigigoonsiminikaaning First Nation P.O. Box 68 Fort Frances, Ont. P9A3M5
Ojibway Nation of Saugeen*	Ojibway Nation of Saugeen Band Office General Delivery Savant Lake, ON P0V 2S0
Lac Des Mille Lacs First Nation*	Lac Des Mille Lacs First Nation 1100 Memorial Avenue, Suite 328 Thunder Bay, ON P7B 4A3
Lac La Croix First Nation*	Lac La Croix First Nation PO Box 640 Fort Frances, ON P9A 3M9
Lac Seul First Nation*	Lac Seul First Nation PO Box 100 Hudson, ON P0V 1X0
Seine River First Nation*	Seine River First Nation PO Box 124 Mine Centre, ON P0W 1H0
Wabigoon Lake First Nation*	Wabigoon Lake Ojibway Nation RR1, Site 115, PO Box 300 Dryden, ON P8N 2Y4
MNO Atikokan and Area Métis Council**	105 Main St E Atikokan, ON P0T 1C0
MNO Northwest Métis Council**	34B King St Dryden, ON P8N 1B3
MNO Thunder Bay Métis Council**	226 South May Street, Main Floor Thunder Bay, ON P7E 1B4
Red Sky Métis Independent Nation	*Red Sky Métis Independent Nation* 406 East Victoria Avenue Thunder Bay, ON P7C 1A5

* Please copy Grand Council Treaty #3 office on correspondence to First Nations that are part of Grand Council Treaty #3:

> Grand Council Treaty #3,
> Territorial Planning Unit
> PO Box 1720
> Kenora, ON P9N 3X7

** Please copy MNO head office on correspondence to MNO regional councils:

Métis Consultation Unit
Métis Nation of Ontario Head Office
500 Old St. Patrick Street, Unit D, Ottawa, Ontario, K1N 9G4
Fax: (613) 725-4225

This rights-based consultation list is based on information that is subject to change. First Nation and Métis communities may make new rights assertions at any time, and other developments (e.g. the discovery of Aboriginal archaeological sites) can occur that may require additional First Nation and/or Métis communities to be notified and/or consulted. If you become aware of potential rights impact on communities that are not listed above at any stage of the consultation and approval process, kindly bring this to the attention of the Ministry of Energy, Northern Development and Mines with any supporting information regarding the claim. The Ministry of Energy, Northern Development and Mines will then assess whether it is necessary to include the community on the rights-based consultation list above.

If you have any questions about this letter or require any additional information, please contact Chloë Lazakis at 416-327-2116 or chloe.lazakis@ontario.ca

Sincerely,

Morgan Owen on behalf of
Samir Adkar
Director
Energy Networks and Indigenous Policy
Ministry of Energy, Northern Development and Mines

C: Patricia Staite, Manager, Environmental Assessments, Hydro One Networks Inc.

MINISTRY OF NORTHERN DEVELOPMENT AND MINES AMENDED DELEGATION LETTER APRIL 15, 2020

Ministry of Energy, Northern Development and Mines

Ministère de l'Énergie, du Développement du Nord et des Mines

77 Grenville Street
6th Floor
Toronto ON M7A 2C1

77, rue Grenville
6e étage
Toronto ON M7A 2C1

Ontario

April 15, 2020 VIA EMAIL

Christine Goulais
Senior Manager, Indigenous Relations
Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario M5G 2P5

Re: Waasigan Transmission Line

Dear Christine Goulais:

This is a letter amendment to the October 25, 2018 letter issued by the Ministry of Energy, Northern Development and Mines (ENDM) to Hydro One Networks Inc. (Hydro One) in regard to the Waasigan Transmission Line. Based on new information provided by Hydro One to the Crown, the Crown has determined that the following Indigenous communities should be consulted on the basis that they have or may have constitutionally protected Aboriginal or Treaty rights that may be adversely affected by the Project. The following Indigenous communities are in addition to those noted in the October 2018 letter.

Community	Mailing Address
Couchiching First Nation*	RMB 2027, R.R. 2 Fort Frances, ON P9A 3M3
Mitaanjigamiing First Nation*	P.O. Box 609 Fort Frances, ON P9A 3M9

*Please copy Grand Council Treaty #3 office on correspondence to First Nations that are part of Grand Council Treaty #3:

Grand Council Treaty #3
Territorial Planning Unit
PO Box 1720
Kenora, ON P9N 3X7

ENDM is assuming a coordinating role within government in relation to rights-based Aboriginal consultation on the Project. If you have any questions or concerns please contact: Jason McCullough, Senior Advisor, Indigenous Energy Policy, Ministry of Energy, Northern Development and Mines at Jason.McCullough@ontario.ca or 416-526-2963.

Sincerely,

Dan Delaquis
Manager, Indigenous Energy Policy

C: Melissa Mauro, Supervisor, Land Use Planning, MNRF
Andrew Evers, Supervisor, Project Coordination – Team 2, MECP

SYSTEM IMPACT ASSESSMENT

Please refer to **Exhibit F, Tab 1, Schedule 1, Attachment 1** for the Final SIA prepared by the IESO (SIA reference # CAA 2022-732).

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

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

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FINAL IESO SYSTEM IMPACT ASSESSMENT

System Impact Assessment Report

Final Report - Public

CAA ID: 2022-732
Project: Waasigan Transmission Line
Connection Applicant: Hydro One Networks Inc.

August 24, 2023

Connecting Today.
Powering Tomorrow.

Acknowledgement

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

Disclaimers

IESO

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

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

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

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

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

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

The IESO provides no comment, representation or opinion, express or implied, with respect to who should bear the cost of IESO requirements for connection in this report and disclaims any liability in connection therewith.

Hydro One

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

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

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

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

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

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

Table of Contents

Project Description

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

Phase 1:

- Build two new 190 km long 230 kV circuits, A30L and A31L, between Lakehead Transformer Station (TS) and Mackenzie TS. The new circuits will be configured on double-circuit towers for the entire length except for a 0.5 km section approximately 16 km from Lakehead TS, where the new circuits and existing 230 kV circuits, A21L and A22L, will be configured on 3 quadruple-circuit towers;
- Install three new 40 Mvar reactors rated at 220 kV: one at Lakehead TS and two at Mackenzie TS;
- Install Line End Open (LEO) protection for A21L, A22L, A30L and A31L;
- Install new local switching schemes for all existing and new reactive devices at Lakehead TS and at Mackenzie TS as described in Table 10 in Appendix D of this report; and
- Change the Northwest Remedial Action Scheme (RAS) selection matrix to include the contingencies involving the loss of A30L and the loss of A31L, and the selections for the new and existing reactors at Lakehead TS and Mackenzie TS as described in Table 9 in Appendix D of this report.

Phase 2:

- Build one new 170 km long 230 kV circuit, D32A, between Mackenzie TS and Dryden TS. The new circuit will be configured on single-circuit towers for the entire length;
- Install LEO protection for D32A and existing 230 kV circuits D26A and F25A;
- Separate sections of 230 kV circuits F25A and D26A such that they do not share a common structure over a distance that exceeds 1.6 km; and
- Change the Northwest RAS selection matrix to include the loss of D32A, and remove the simultaneous loss of F25A and D26A contingency as described in Table 9 in Appendix D of this report.

The connection applicant has confirmed that simultaneous planned outages for maintenance, including equipment clearance needs, are not expected to occur to more than two of circuits A21L, A22L, A30L and A31L, and that the likelihood of a simultaneous loss to three or four of these circuits is expected to be significantly lower than the simultaneous loss of the existing A21L and A22L circuits that currently share common towers.

Appendix B of this report shows simplified single line diagrams for the connection of the project to the local transmission system. The planned in-service date for Phases 1 and 2 are close to the end of 2025 and 2027, respectively.

Notification of Conditional Approval

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

Assessment Findings

System studies were carried out to identify the impact of the project on system voltages in accordance to the Ontario Resource and Transmission Adequacy Criteria (ORTAC) and in line with applicable reliability standards. The studied scenarios and main assumptions are available in Appendix C of this report. The detailed study results are available in Appendix D of this report. Based on the assessment results, we have identified the following assessment findings:

1. The incorporation of the project will result in new contingencies as described in Appendix C of this report and changes to the selection matrix for the Northwest RAS as described in Table 9 in Appendix D of this report.
2. During an outage to circuit breaker HL93 at Mackenzie TS, Atikokan GS can be islanded with the new adjacent reactor following a contingency to circuit breaker PL22.

IESO Requirements for Connection

Specific Requirements

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

1. Hydro One shall install Remedial Action Scheme (RAS) facilities to include the project in the Northwest RAS as per Appendix D of this report. During the IESO Market Registration process, a revised Facility Description Document (FDD) for Northwest RAS must be provided and finalized at least nine months prior to in-service. The FDD must contain the finalized RAS matrix as well as expected operating times. The actual operating times must be measured during commissioning and documented as a Performance Validation Record.

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

   Hydro One shall ensure that the RAS facilities comply with NPCC Reliability Reference Directory #7 as per the RAS type classification which will be finalized during the Market Registration process. To avoid any delay to the project, it is strongly recommended the RAS facilities be designed to meet NPCC Reliability Reference Directory #7 for NPCC Type I RAS before the RAS type classification is finalized. If deemed or expected to be a Type II or Limited Impact RAS, the transmitter shall ensure the RAS facilities have provisions to comply with NPCC Reliability

Reference Directory #7 for Type I RAS in case the RAS is re-classified as NPCC Type I RAS in the future as the system evolves.

Telemetry, including but not limited to, MW, Mvar and breaker status for the feeders/equipment tripped by the RAS, as specified by the IESO at the time of registration, shall be provided.

2. Hydro One shall install local reactive devices switching schemes at Lakehead TS and Mackenzie TS incorporating all existing and new reactive devices as described in Table 10 in Appendix D of this report. The settings for these schemes will be finalized during the IESO's Market Registration process. As well, specifically regarding the new switching scheme at Lakehead TS, the connection applicant shall ensure, with consultation with the IESO, that it is well coordinated with the existing dynamic reactive devices at Lakehead TS.
3. Hydro One shall submit a final outage plan that must be accepted by the IESO at least one year before the date of the first outage to incorporate Phase 1 of the project.
4. The connection applicant shall ensure that Atikokan GS can be islanded with the new adjacent reactor at Mackenzie TS post-contingency during the aforementioned outage conditions without damage to equipment at either facility.

General Requirements

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

Recommendations

1. The connection applicant is strongly recommended to consider revising the design of the two new 230 kV circuits between Lakehead TS and Mackenzie TS so that they are configured on double-circuit towers for their entire length and not utilize any quadruple-circuit towers. This would best support system reliability and resiliency in this area of the province that is prone to adverse weather from the spring to fall months, which poses a risk of simultaneous multiple circuit contingencies due to tower sharing.
2. To improve power system operability, the connection applicant is recommended to work with the IESO via the Bulk Planning process to:
    a. replace reactor R1 at Lakehead TS with two 40 MVar reactors;
    b. replace the failed dynamic reactive device C8 at Lakehead TS with new reactive device(s); and,
    c. reconfigure transmission elements at Lakehead TS, Mackenzie TS and Dryden such that all ORTAC guidelines for station configuration are met.

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 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 transmitter 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 reliability standards, the transmitter is encouraged to contact orcp@ieso.ca and also visit the Ontario Reliability Compliance Program webpage.
3. The connection applicant shall ensure that the project's equipment meet the voltage requirements specified in section 4.2 and section 4.3 of the Ontario Resource and Transmission Assessment Criteria (ORTAC).
4. According to Section 6.1.2 of the TSC, the connection applicant must ensure the project's transmission connection equipment is designed to withstand the fault levels in the area. According to Section 6.4.4 of the TSC, if any future system changes result in an increased fault level higher than the project's equipment capability, the connection applicant is required to replace that equipment with higher rated equipment capable of withstanding the increased fault level, up to the maximum fault level specified in Appendix 2 of the TSC.

   It is the connection applicant's responsibility to verify that all equipment and circuit breakers within the project are appropriately sized for the local fault levels.
5. The connection applicant shall ensure that the circuit breakers/switchers installed at the project have rated interrupting time that satisfies Appendix 2 of the TSC. Fault interrupting devices installed at the project must be able to interrupt fault currents at the applicable maximum continuous voltage as specified in Section 4.2 and Section 4.3 of ORTAC.

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

   Associated overvoltage protective relaying must be set to ensure that the project's equipment does not automatically trip for voltages up to 5% above the equipment's corresponding maximum continuous voltage as specified in section 4.2 of the ORTAC.

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

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

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

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

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

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

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

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

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

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

10. If the connection applicant is currently a participant in the Ontario Power System Restoration Plan, its restoration participant attachment is required to be updated to include the project according to Market Manual 7.8. For either an existing or newly identified participant in the Ontario Power System Restoration Plan, details regarding restoration participant requirements will be finalized during the IESO Market Registration process.

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

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

Appendix B: Project Data (Confidential)

Appendix C: Study Scope of Work (Confidential)

Appendix D: Detailed Study Results (Confidential)

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Powering Tomorrow.

CUSTOMER IMPACT ASSESSMENT

Please refer to **Exhibit G, Tab 1, Schedule 1, Attachment 1** for the Final CIA prepared by Hydro One.

The CIA report has reviewed the impact on the local area customers due to the system configuration modification to incorporate the Project. This report concludes that the resulting voltage changes on the areas high-voltage and low-voltage buses are within planning limits. It is recommended that area customers review the impact of the short circuit change on their facilities.

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FINAL CUSTOMER IMPACT ASSESSMENT

Hydro One Networks Inc.
483 Bay St
Toronto ON M5G 2P5

CUSTOMER IMPACT ASSESSMENT

WAASIGAN TRANSMISSION LINE PROJECT

CIA ID:	2023-13
Revision:	**Final**
Date:	August 28th, 2023

Issued by:	Transmission System Planning – North Hydro One Networks Inc.

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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) set out in Hydro One's Ontario Energy Board (OEB) approved Transmission Connection Procedures) and Section 6.41 of the OEB's Transmission System Code. Hydro One performs a CIA where Hydro One has determined that one or more existing Hydro One transmission customers may be impacted by a proposed new or modified connection.

This CIA was prepared by Hydro One based on information available to or provided to Hydro One at the time the CIA was performed regarding the: (i) proposed new or modified connection described herein ("Project"); and (ii) existing connection of one or more transmission customers that Hydro One determined prior to conducting the CIA that may be impacted by the Proposed Project. The CIA is intended to highlight impacts of the Project, if any, on existing Hydro One transmission customers early in the project development process and thus allow an opportunity for impacted Hydro One transmission customers to bring forward any concerns that they may have. Subsequent changes to the required modifications or the implementation plan may affect the impacts of the proposed Project. The results of this CIA are also subject to change to accommodate the requirements of the IESO and/or other regulatory requirements.

Hydro One shall not be liable to any person or entity reading or receiving the CIA (including, without limitation, any existing transmission customer that Hydro One determined may be impacted by the Project prior to conducting the CIA) under any circumstances whatsoever for any:

- direct damages resulting from or in any way related to the reliance on, acceptance or use of the CIA or its contents unless such liability arises under section 6.4 of the Transmission System Code or the terms of a contract made between Hydro One and that person or entity with respect to the proposed Project; and/or any indirect or consequential damages, loss of profit or revenues, business interruption losses, loss of contract or loss of goodwill, special damages, punitive or exemplary damages, whether any of the said liability, loss or damages arises in contract, tort or otherwise.

Table of Contents

1.0 INTRODUCTION

1.1 Purpose

This Customer Impact Assessment ("CIA") study assesses the potential impact of the proposed Waasigan Transmission Line project ("the Project") on the area transmission connected customers.

The Project consists of a new 230 kV double-circuit transmission line that will span from the existing Lakehead TS to the existing Mackenzie TS (also referred to herein as the "Waasigan Phase 1 Transmission Line", or "Phase 1"), and a new 230 kV single-circuit transmission line from the existing Mackenzie TS to the existing Dryden TS (also referred to herein as the "Waasigan Phase 2 Transmission Line", or "Phase 2"), including associated station facilities at these terminal stations.

The proposed Project's major facilities, along with their general locations are summarized as follows:

1) Approximately 190km of 230 kV double-circuit transmission line from Lakehead TS to the Mackenzie TS on a combination of, i) existing 230 kV transmission corridors that require widening to accommodate the new facilities, and ii) additional new corridor lands. Phase 1's expected in-service date is December 2025.

2) Approximately 170km 230 kV single-circuit transmission line from Mackenzie TS to Dryden TS on a combination of, i) existing 230 kV transmission corridors that require widening to accommodate the new facilities, and ii) additional new corridor lands. Phase 2's expected in-service date is December 2027.

3) Terminal station modifications at Lakehead TS, Mackenzie TS, and Dryden TS to accommodate the new Phase 1 and Phase 2 proposed transmission circuits.

The single line diagram and a geographical area overview of this Project are shown in Figures A1 and A2 in Appendix A.

The existing Northwest Remedial Action Scheme (RAS) is to be modified to account for additional contingencies due to the addition of new 230kV circuits, with no new Load Rejection (LR) or Generation Rejection (GR) required as part of the modification.

In accordance with Section 6 of the Ontario Energy Board's Transmission System Code, Hydro One Networks Inc. ("Hydro One") has carried out this Customer Impact Assessment (CIA) study to assess the impact of the proposed projects on existing customers in the affected area. The primary focus of this assessment is possible short circuit and reliability impact on transmission connected customers following the incorporation of the Project. This study does not evaluate the overall impact of these projects on the bulk electricity system. The impact of the new facilities on the bulk electricity system is the subject of the System Impact Assessment (SIA) carried out by the Independent Electricity System Operator (IESO).

As part of the Connection Assessment and Approval (CAA) process, the IESO has carried out a System Impact Assessment (SIA) for the Project, and has documented the findings in the Final Report, CAA ID 2022-732 dated August 24th, 2023.

On August 2nd 2023 a draft version of this report was sent to customers listed in Table 2 for review and comments. Hydro One has addressed all comments and incorporated them within this final report as applicable.

1.2 Area Customers

This study focuses on transmission connected customers supplied by 115kV and 230kV circuits shown in Table 1:

Table 1: 230kV and 115kV Transmission Circuits

Connecting Stations	Circuit ID	Voltage (kV)
Mackenzie x Dryden	D26A	230
Mackenzie x Fort Frances	F25A	230
Dryden x TCPL Vermilion Bay x Kenora	K23D	230
Fort Frances x Kenora	K24F	230
Mackenzie x Marmion Lake x Atikokan	N93A	230
Mackenzie x Lakehead	A21L	230
Mackenzie x Lakehead	A22L	230
Marathon x Lakehead	M23L	230
Marathon x Lakehead	M24L	230
Marathon x Lakehead	M37L	230
Marathon x Lakehead	M38L	230
Dinorwic Jct x Pickle Lake	W54W	230
Kenora x Rabbit Lake	15M1	115
Ignace x Camp Lake x Valora x Mattabi	29M1	115
Mackenzie x Moose Lake	A3M	115
Moose Lake x Sapawe x Shabaqua x Stanley x Murillo x Birch	B6M	115
Dryden x Domtar Dryden	D5D	115
Fort Frances x Burleigh	F1B	115
Kenora x Norman	K2M	115
Dryden x Sam Lake x Eton x Vermilion Bay x Rabbit Lake	K3D	115
White Dog x Minaki x Rabbit Lake	K4W	115
Fort Frances x Ainsworth x Nestor Falls x Sioux Narrows x Rabbit Lake	K6F	115
Kenora x Weyerhaeuser Ken x Rabbit Lake	K7K	115
Moose Lake x Valerie Falls x Mill Creek	M1S	115

Moose Lake x Ignace x Dryden	M2D	115
Rabbit Lake x Keewatin x Forgie	SK1	115
White Dog x Caribou Falls	W3C	115
Nipigon x Red Rock	56M1	115
Reserve x Nipigon	57M1	115
Alexander x Port Arthur	A6P	115
Lakehead x Port Arthur	L3P	115
Lakehead x Port Arthur	L4P	115
Port Arthur x Birch	P3B	115
Port Arthur x Birch	P7B	115
Port Arthur x Conmee	P5M	115
Thunder Bay x Birch	B9	115
Thunder Bay x Birch	B14	115
Thunder Bay x Birch	B5	115
Thunder Bay x Birch	B15	115
Lakehead x Pine Portage x Birch	R1LB	115
Lakehead x Pine Portage x Birch	R2LB	115
Silver Falls x Lac Des Iles x Conmee	S1C	115
Alexander x Cameron Falls	C1A	115
Alexander x Cameron Falls	C2A	115
Alexander x Cameron Falls	C3A	115
Alexander x Pine Portage	R9A	115
Ear Falls x Selco x Slate Falls x Cat Lake x Pickle Lake	E1C	115
Pickle Lake x Crow River x Musselwhite	C2M	115
Pickle Lake x Wataynikaneyap	C3W	115
Ear Falls x Balmer x Red Lake	E2R	115
Ear Falls x Scout Lake x Dryden	E4D	115
Manitou Falls x Ear Falls	M3E	115

The areas considered by this CIA are shown in Figure A3 in Appendix A. Affected customers are shown in Table 2 below:

Table 2: Transmission Connected Customers

230kV Connected Station	**Customer**
Atikokan CGS	Ontario Power Generation Inc.
Dinorwic CSS	Wataynikaneyap Power
Greenwich Lake Wind Farm CGS	Renewable Energy Systems Limited
Pickle Lake CTS	Wataynikaneyap Power
Rainy River Gold CTS	New Gold Inc.
Vermilion Bay CTS	TC Pipelines, LP
115kV Connected Station	**Customer**
Thunder Bay Sub-Region	
Alexander CGS	Ontario Power Generation Inc.
Birch TS	Synergy North
Cameron Falls CGS	Ontario Power Generation Inc.
Ft Williams TS	Synergy North
Kraft CTS	Resolute Forest Products
Lac Des Iles Mine CTS	Impala Canada Ltd.
Murillo DS	Hydro One Distribution
Nipigon DS	Hydro One Distribution
Pine Portage CGS	Ontario Power Generation Inc.
Port Arthur TS #1	Hydro One Distribution / Synergy North
Red Rock DS	Hydro One Distribution
Silver Falls CGS	Ontario Power Generation Inc.
Thunder Bay CTS	Resolute Forest Products
West of Thunder Bay Sub-Region	
Agimak DS	Hydro One Distribution
Ainsworth CTS	West Fraser Timber Co. Ltd. (Formerly Norbord Inc.)
Barwick TS	Hydro One Distribution
Burleigh DS	Hydro One Distribution
Calm Lake CGS	Ontario Power Generation Inc.
Clearwater Bay DS	Hydro One Distribution
Crilly DS	Hydro One Distribution
Domtar Dryden CTS	Domtar Corporation
Eton DS	Hydro One Distribution
Fort Frances MTS	Fort Frances Power Corp
Keewatin DS	Hydro One Distribution
Kenora CGS	Ontario Power Generation Inc.
Kenora DS	Hydro One Distribution
Kenora MTS	Synergy North
Margach DS	Hydro One Distribution
Mattabi CTS	Glencore Canada Corporation
Minaki DS	Hydro One Distribution
Moose Lake TS	Atikokan Hydro Inc.
Nestor Falls DS	Hydro One Distribution
Norman CGS	Ontario Power Generation Inc.
Sam Lake DS	Hydro One Distribution

Sapawe DS	Hydro One Distribution
Shabaqua DS	Hydro One Distribution
Sioux Narrows DS	Hydro One Distribution
Sturgeon Falls CGS	Ontario Power Generation Inc.
Valerie Falls CGS	Ontario Power Generation Inc.
Valora DS	Hydro One Distribution
Vermilion Bay DS	Hydro One Distribution
Weyerhaeuser Kenora CTS	Weyerhaeuser Company
Whitedog CGS	Ontario Power Generation Inc.
Whitedog DS	Hydro One Distribution
North of Dryden Sub-Region	
Balmer CTS	Evolution Mining Gold Operations Ltd.
Cat Lake MTS	Hydro One Distribution
Crow River DS	Hydro One Distribution
Ear Falls CGS	Ontario Power Generation Inc.
Ear Falls DS	Hydro One Distribution
Esker CTS	Newmont Corporation
Lac Seul CGS	Ontario Power Generation Inc.
Manitou Falls CGS	Ontario Power Generation Inc.
Musselwhite CTS	Newmont Corporation
Perrault Falls DS	Hydro One Distribution
Pickle Lake CTS	Wataynikaneyap Power
Red Lake CSS	Wataynikaneyap Power
Red Lake TS	Hydro One Networks Inc.
Slate Falls DS	Hydro One Distribution

2.0 TECHNICAL STUDY

The purpose of this CIA is to assess the potential impacts of the proposed new transmission facilities on the existing connected load and generation customers in the affected area.

A review of the following potential impacts on existing customers is conducted in this CIA:

1) Thermal Assessment (IESO)
2) Voltage
3) Short-Circuit Current

The Single Line Diagram presented in Figure A1 shows the final system configuration in the northwest with the incorporation of the Project.

2.1 Thermal Assessment (IESO)

The final SIA completed by the IESO did not identify thermal rating criteria violations in any contingency scenarios under various Planning Event Types based on NERC TPL-001. Please refer to IESO document CAA 2022-732 for more details. The new Waasigan transmission lines are projected to allow an increase of existing loads and connection of future loads as forecasted under Regional and Bulk Planning initiatives. Detailed thermal assessment will be conducted once individual load increase applications are submitted.

No additional thermal assessment will be conducted in this CIA report.

2.2 Voltage Assessment

Study Assumptions:

- Studies were conducted using the 2022-2023 Winter Peak Base Case model utilizing the Siemens Power System Simulator for Engineering (PSS/E)
- The assessment period for the Final CIA Report accounts for load forecasts up to 10 years (year 2037) post the in-service year (year 2027) of Phase 2.
- All planned facilities for which work has been initiated and are referenced in the 2023 Northwest RIP Report are assumed to be in-service.
- Adequacy assessment is conducted as per ORTAC.
- New facilities data was acquired directly from the vendor, and with reference to the SIA Application Package

This CIA assessed area voltages under the following scenarios:

1) After the incorporation of the Project Phase 1 ONLY
2) After the incorporation of BOTH Project Phases 1 and 2, and
    a. N-1 Contingency involving loss of A21L[1]
    b. N-2 Contingency involving loss of A21L + A22L[2]

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

The resulting voltage changes on area high-voltage and select low-voltage buses are within ORTAC planning limits, and in turn suggests a strong backbone system with the incorporation of the Waasigan transmission lines in Northwestern Ontario. Please see Appendix C for further details.

2.3 Short Circuit Assessment

The proposed transmission reinforcement has a relatively small impact on short-circuit Levels in the area since, it does not significantly reduce the net (equivalent) impedance between the existing sources of short-circuit current, i.e., generators, and the customer connection points.

Appendix B shows the short-circuit currents (Symmetrical and Asymmetrical; for three-phase faults and single-phase-to-ground faults) at the main buses in the area, before and after the connection of the Project, with the assumption of all existing and committed generators being in service, including Atikokan Generating Station. Area customers are requested to review the short circuit results and verify that fault levels are within their asset and equipment ratings.

Appendix B tables show that fault levels remain within the OEB TSC requirements (See Table 3) and that the levels are within Hydro One breaker ratings, except for 13.8kV bus fault currents upstream of Whitedog DS, which exceed fault levels dictated by TSC *both before and after* the Project comes into service. Ontario Power Generation (OPG) is asked to confirm these fault current values are within its respective LV breaker ratings.

[1] Loss of A21L is reflective of loss of any of the 230kV circuits between Lakehead TS and Mackenzie TS due to similar conductor type and impedance values.

[2] Loss of A21L + A22L is reflective of loss of any combination of 230kV circuit pairs between Lakehead TS and Mackenzie TS due to similar conductor type and impedance values.

Table 3: TSC Fault Current Limits

Nominal Voltage (kV)	Max 3-Phase Fault (kA)	Max SLG Fault (kA)
230	63	63
115	50	50
27.6 (4-wire)	17	12
13.8	21	10

3.0 CUSTOMER RELIABILITY

3.1 Impact to Customer Reliability

Reliability of the main transmission system in the Northwest will increase because of the Project. The additional transmission lines will assist in planning outages such as those required for maintenance work as well as improve system performance during unplanned outages such as during storms.

While the existing Northwest RAS[3] will remain in place after the completion of the Project, the reliance on the RAS to ensure supply adequacy and alleviating system constraints will be decreased. Therefore, the arming of RAS will be limited to times of outage conditions or local generation shortages.

3.2 Customer Impact During Construction

The outage schedule during the construction work will be developed during the detailed engineering and execution phase of the project. Construction will be staged by Hydro One and the IESO to minimize possible customer interruptions. The outage and recall durations will be minimized, and the risk will be managed with proper outage planning and co-ordination. The schedules will be communicated to the affected customers and stakeholders in advance of the outages.

4.0 CONCLUSION

This report has reviewed the impact on the local customers due to the system configuration modification to incorporate the Project. This report concludes that the resulting voltage changes on area high-voltage and low-voltage buses are within planning limits. It is recommended that area customers review the impact of the short circuit change on their facilities.

[3] RAS is formerly known as Special Protection System (SPS)

5.0 Appendix A

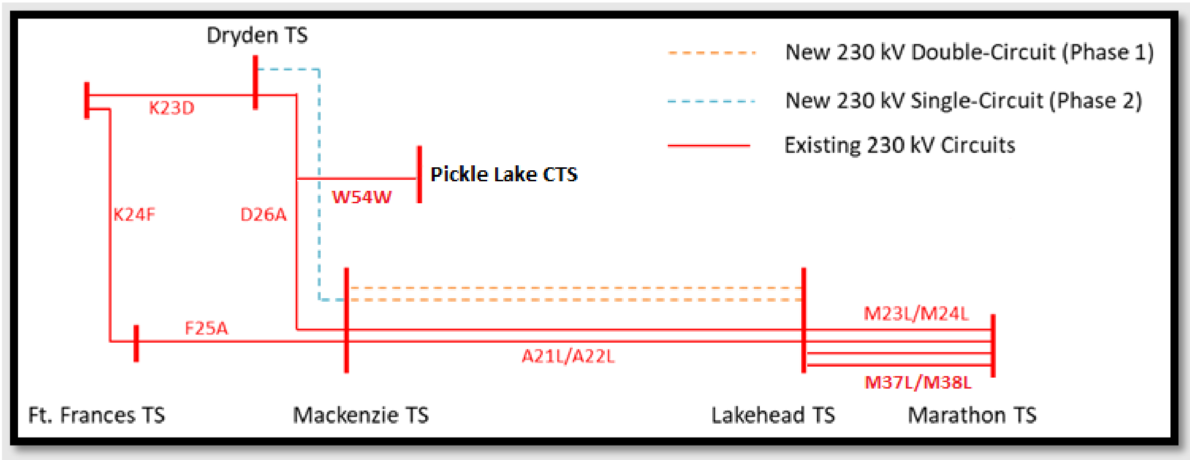

Fig. A1: Single Line Diagram – Wassigan Transmission Line Project – Phase 1 and Phase 2

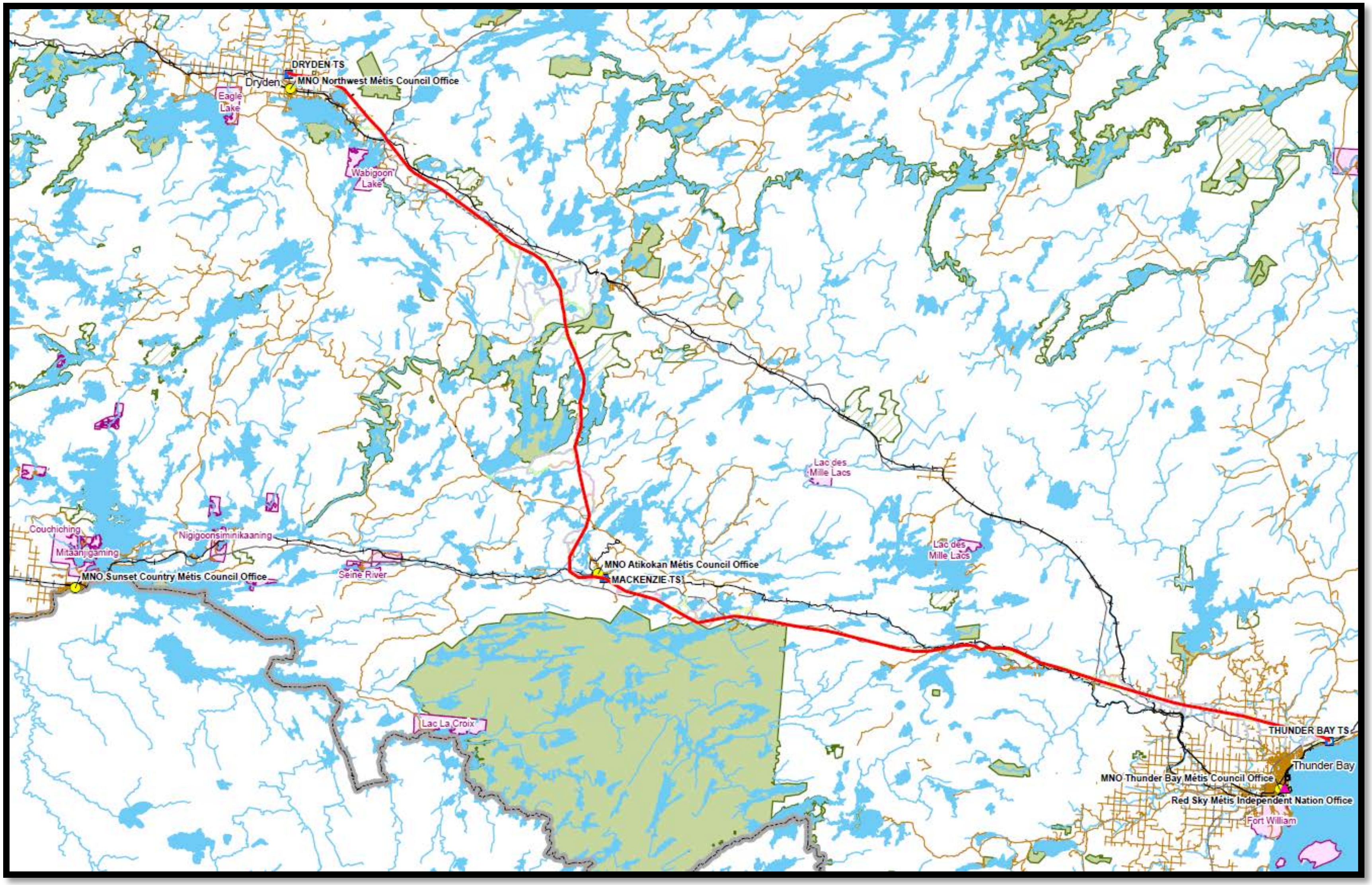

Fig. A2: Geographcal Overview of the Wassigan Transmission Line Project – Phase 1 and Phase 2

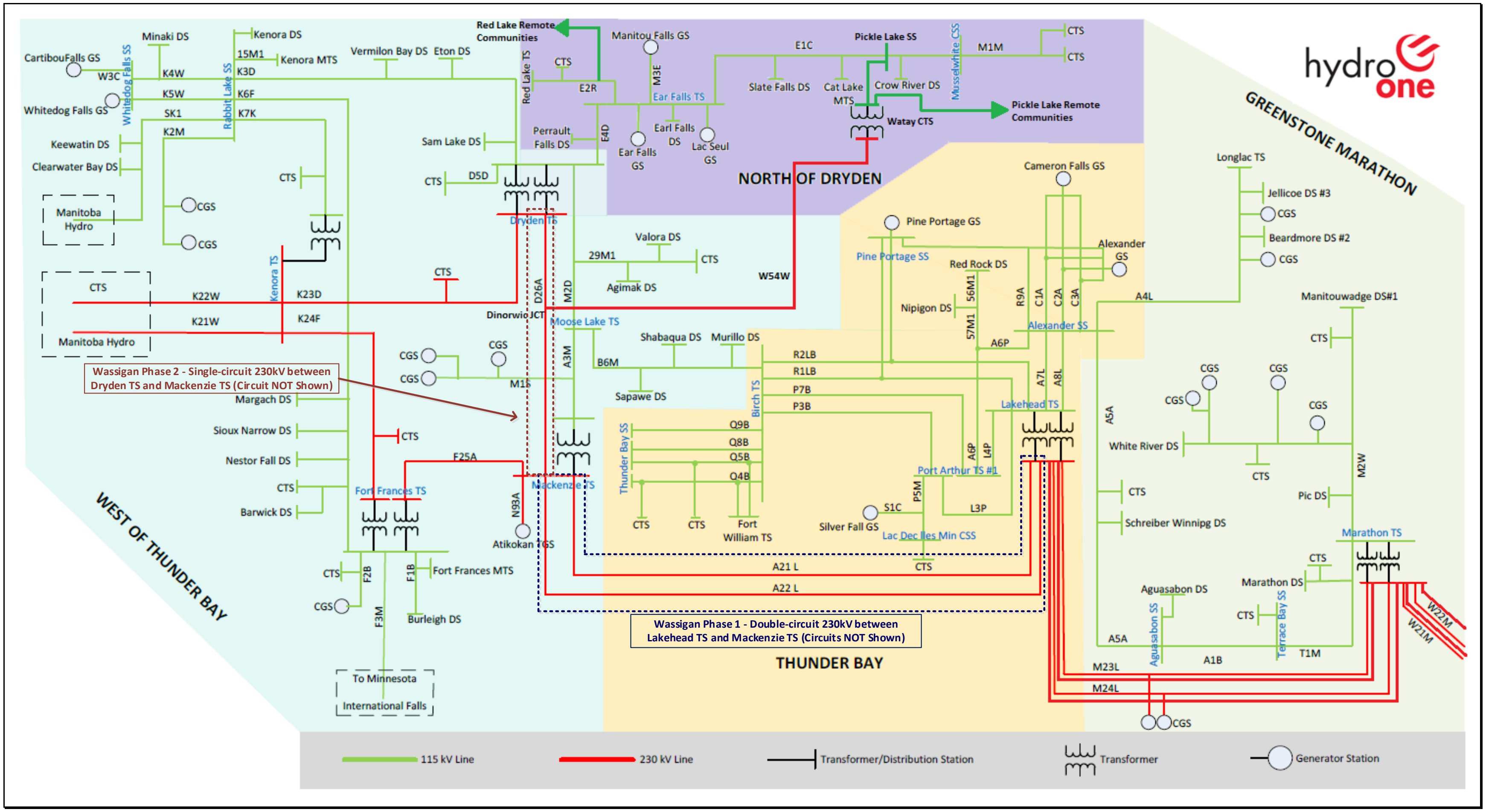

Fig. A3: Single Line Diagram of the Ontario Northwest Region

6.0 Appendix B

Table B11: Existing Short Circuit Levels

Station / Bus	Bus Voltage (kV)	Max Voltage (kV)[4]	3-Φ Fault (kA)		L-G Fault (kA)	
			Symmetrical	Asymmetrical	Symmetrical	Asymmetrical
Major 115kV and 230kV Terminal Station Bus along Waasigan Route Corridor						
Dryden TS	230	250	4.501	4.967	4.742	5.359
Dryden TS	115	132	6.149	7.138	6.182	6.746
Lakehead TS	230	250	7.388	8.448	7.606	9.118
Lakehead TS	115	132	15.604	17.710	17.598	20.905
Mackenzie TS	230	250	7.190	8.322	7.109	8.377
Mackenzie TS	115	132	6.051	7.470	7.280	9.380
230kV Connected Stations						
Atikokan CGS	230	250	5.420	7.080	6.053	8.196
Dinorwic CSS	230	250	3.543	3.792	3.010	3.120
Greenwich Lake Wind Farm CGS – M23L	230	250	3.745	4.062	3.769	4.262
Greenwich Lake Wind Farm CGS – M24L	230	250	3.739	4.052	3.767	4.255
Pickle Lake CTS	230	250	0.955	0.973	1.149	1.191
Rainy River Gold CTS	230	250	2.762	2.917	3.194	3.500
Vermilion Bay CTS	230	250	3.584	3.819	2.971	3.072
115kV Connected Stations						
Thunder Bay Sub-Region						
Alexander CGS – C1A	115	132	9.237	10.347	9.798	11.150
Alexander CGS – C2A	115	132	9.238	10.353	9.803	11.158
Alexander CGS – C3A	115	132	9.231	10.336	9.790	11.132
Alexander CGS – R9A	115	132	9.241	10.336	9.797	11.124
Birch TS	115	132	13.705	15.245	10.928	11.803
Cameron Falls CGS – C1A	115	132	8.301	9.057	8.624	9.442
Cameron Falls CGS – C2A	115	132	8.260	9.052	8.674	9.567
Cameron Falls CGS – C3A	115	132	8.204	8.905	8.526	9.190
Ft Williams TS – Q4B	115	132	11.153	12.484	8.954	9.701
Ft Williams TS – Q5B	115	132	10.179	11.246	7.722	8.116
Kraft CTS	115	132	8.660	9.695	6.367	6.571
Lac Des Iles Mine CTS	115	132	1.213	1.214	0.801	0.801
Murillo DS	115	132	6.618	6.781	4.040	4.138
Nipigon DS	115	132	4.764	4.795	3.439	3.442
Pine Portage CGS	115	132	7.422	8.605	7.874	9.624
Port Arthur TS #1 – T1	115	132	12.077	12.893	11.745	12.735
Port Arthur TS #1 – T2	115	132	11.972	12.801	11.678	12.684
Red Rock DS	115	132	3.911	3.917	2.715	2.717
Silver Falls CGS	115	132	3.393	3.724	3.499	4.090
Thunder Bay CTS	115	132	10.511	12.915	10.287	13.202

[4] Maximum allowable continuous voltage utilized for short circuit calculation.

West of Thunder Bay Sub-Region						
Agimak DS – T2	115	132	1.906	1.909	1.117	1.118
Agimak DS – T1	115	132	1.913	1.916	1.122	1.123
Ainsworth CTS	115	132	2.039	2.049	2.236	2.285
Barwick TS	115	132	2.069	2.082	2.300	2.356
Burleigh DS	115	132	4.386	4.515	3.597	3.651
Caribou Falls CGS	115	132	3.947	4.609	4.351	5.427
Calm Lake CGS	115	132	2.162	2.333	2.046	2.201
Clearwater Bay DS	115	132	2.152	2.155	1.409	1.410
Crilly DS	6.6	7	9.794	12.685	0.000	0.000
Domtar Dryden CTS	115	132	6.149	7.138	6.182	6.746
Eton DS	115	132	5.035	5.244	4.208	4.300
Fort Frances MTS	115	132	7.690	8.585	9.217	10.703
Keewatin DS	115	132	4.598	4.699	3.461	3.526
Kenora CGS	115	132	5.347	5.665	4.180	4.349
Kenora DS	115	132	6.040	6.506	5.157	5.406
Kenora MTS	115	132	5.742	6.126	4.799	4.981
Margach DS	115	132	4.899	5.091	3.768	3.835
Mattabi CTS	115	132	1.044	1.045	0.578	0.579
Minaki DS	115	132	4.318	4.530	3.459	3.622
Moose Lake TS	115	132	5.114	5.509	4.988	5.375
Nestor Falls DS	115	132	2.840	2.857	1.907	1.909
Norman CGS	115	132	5.319	5.627	4.143	4.299
Sam Lake DS	115	132	1.628	1.646	0.937	0.955
Sapawe DS	115	132	3.265	3.332	2.298	2.342
Shabaqua DS	115	132	3.113	3.141	1.771	1.797
Sioux Narrows DS	115	132	2.972	3.006	1.878	1.881
Sturgeon Falls CGS	115	132	2.116	2.303	1.986	2.225
Valerie Falls CGS	115	132	4.001	4.219	3.316	3.460
Valora DS	115	132	1.205	1.206	0.674	0.675
Vermilion Bay DS	115	132	3.633	3.693	2.422	2.431
Weyerhaeuser Kenora CTS	115	132	5.666	6.132	6.395	7.140
Whitedog CGS	115	132	4.897	5.617	5.192	6.395
Whitedog DS	13.8	14.6	33.471	36.958	28.594	36.314
North of Dryden Sub-Region						
Balmer CTS	115	132	1.300	1.325	1.355	1.387
Cat Lake MTS	115	132	1.014	1.014	0.736	0.737
Crow River DS	115	132	1.885	1.925	2.359	2.449
Ear Falls CGS	115	132	3.077	3.353	3.517	3.933
Ear Falls DS	12.5	13.25	3.355	3.478	3.539	3.883
Ear Falls TS	115	132	3.077	3.353	3.517	3.933
Lac Seul CGS	115	132	3.077	3.353	3.517	3.933
Manitou Falls CGS	115	132	2.785	3.182	3.157	3.766
Perrault Falls DS	115	132	2.888	2.959	2.199	2.249
Pickle Lake CTS	115	132	1.893	1.934	2.381	2.474
Red Lake CSS	115	132	1.418	1.444	1.632	1.682
Red Lake TS	115	132	1.371	1.395	1.641	1.691
Slate Falls DS	115	132	1.164	1.165	0.832	0.832
Esker CTS	115	132	0.686	0.759	0.384	0.394
Musselwhite CTS	115	132	0.676	0.743	0.378	0.388

Table B2: Short Circuit Levels – After Project Phase 1 I/S

Station / Bus	Bus Voltage (kV)	Max Voltage (kV)[5]	3-Φ Fault (kA)		L-G Fault (kA)	
			Symmetrical	Asymmetrical	Symmetrical	Asymmetrical
Major 115kV and 230kV Terminal Station Bus along Waasigan Route Corridor						
Dryden TS	115	132	6.828	7.636	8.297	9.559
Dryden TS	230	250	4.121	4.557	4.411	5.001
Lakehead TS	115	132	16.315	18.604	18.370	21.907
Lakehead TS	230	250	8.053	9.213	8.269	9.886
Mackenzie TS	115	132	6.027	7.429	7.246	9.325
Mackenzie TS	230	250	6.994	8.101	6.903	8.152
230kV Connected Stations						
Atikokan CGS	230	250	5.978	7.737	6.571	8.815
Dinorwic CSS	230	250	3.641	3.888	3.060	3.168
Greenwich Lake Wind Farm CGS – M23L	230	250	3.873	4.192	3.863	4.359
Greenwich Lake Wind Farm CGS – M24L	230	250	3.867	4.182	3.862	4.352
Pickle Lake CTS	230	250	0.961	0.978	1.154	1.196
Rainy River Gold CTS	230	250	2.798	2.952	3.227	3.532
Vermilion Bay CTS	230	250	3.633	3.867	2.994	3.093
115kV Connected Stations						
Thunder Bay Sub-Region						
Alexander CGS – C1A	115	132	9.319	10.427	9.860	11.209
Alexander CGS – C2A	115	132	9.321	10.433	9.864	11.218
Alexander CGS – C3A	115	132	9.313	10.416	9.852	11.191
Alexander CGS – R9A	115	132	9.323	10.415	9.859	11.183
Birch TS	115	132	14.056	15.607	11.088	11.961
Cameron Falls CGS – C1A	115	132	8.366	9.120	8.671	9.487
Cameron Falls CGS – C2A	115	132	8.324	9.115	8.722	9.612
Cameron Falls CGS – C3A	115	132	8.269	8.967	8.572	9.234
Ft Williams TS – Q4B	115	132	11.345	12.677	9.040	9.785
Ft Williams TS – Q5B	115	132	10.358	11.426	7.794	8.186
Kraft CTS	115	132	8.780	9.815	6.412	6.614
Lac Des Iles Mine CTS	115	132	1.215	1.217	0.801	0.802
Murillo DS	115	132	6.667	6.828	4.053	4.151
Nipigon DS	115	132	4.789	4.818	3.448	3.451
Pine Portage CGS	115	132	7.473	8.656	7.913	9.661
Port Arthur TS #1 – T1	115	132	12.445	13.279	12.010	13.013
Port Arthur TS #1 – T2	115	132	12.328	13.175	11.935	12.952
Red Rock DS	115	132	3.928	3.933	2.720	2.722
Silver Falls CGS	115	132	3.411	3.741	3.512	4.103
Thunder Bay CTS	115	132	10.646	13.053	10.375	13.296
West of Thunder Bay Sub-Region						
Agimak DS – T2	115	132	1.918	1.921	1.120	1.121
Agimak DS – T1	115	132	1.925	1.928	1.125	1.126
Ainsworth CTS	115	132	2.044	2.055	2.240	2.289
Barwick TS	115	132	2.075	2.087	2.305	2.361
Burleigh DS	115	132	4.418	4.547	3.612	3.666
Caribou Falls CGS	115	132	3.953	4.615	4.356	5.432
Calm Lake CGS	115	132	2.180	2.350	2.056	2.212
Clearwater Bay DS	115	132	2.156	2.159	1.410	1.411

[5] Maximum allowable continuous voltage utilized for short circuit calculation.

Crilly DS	6.6	7	9.811	12.704	0.000	0.000
Domtar Dryden CTS	115	132	6.228	7.215	6.234	6.797
Eton DS	115	132	5.086	5.293	4.232	4.323
Fort Frances MTS	115	132	7.792	8.686	9.315	10.800
Keewatin DS	115	132	4.618	4.718	3.468	3.533
Kenora CGS	115	132	5.373	5.690	4.191	4.359
Kenora DS	115	132	6.075	6.539	5.173	5.422
Kenora MTS	115	132	5.773	6.156	4.813	4.995
Margach DS	115	132	4.922	5.113	3.777	3.844
Mattabi CTS	115	132	1.047	1.049	0.579	0.579
Minaki DS	115	132	4.331	4.542	3.465	3.627
Moose Lake TS	115	132	5.242	5.638	5.079	5.466
Nestor Falls DS	115	132	2.851	2.867	1.910	1.912
Norman CGS	115	132	5.345	5.652	4.154	4.309
Sam Lake DS	115	132	1.634	1.651	0.938	0.956
Sapawe DS	115	132	3.297	3.364	2.311	2.354
Shabaqua DS	115	132	3.113	3.142	1.772	1.798
Sioux Narrows DS	115	132	2.982	3.015	1.881	1.883
Sturgeon Falls CGS	115	132	2.134	2.319	1.996	2.234
Valerie Falls CGS	115	132	4.074	4.291	3.353	3.496
Valora DS	115	132	1.209	1.211	0.675	0.676
Vermilion Bay DS	115	132	3.655	3.714	2.429	2.437
Weyerhaeuser Kenora CTS	115	132	5.702	6.167	6.425	7.170
Whitedog CGS	115	132	4.910	5.629	5.201	6.404
Whitedog DS	13.8	14.6	33.501	36.986	28.609	36.329
North of Dryden Sub-Region						
Balmer CTS	115	132	1.302	1.326	1.356	1.388
Cat Lake MTS	115	132	1.015	1.016	0.737	0.737
Crow River DS	115	132	1.895	1.934	2.369	2.458
Ear Falls CGS	115	132	3.084	3.360	3.523	3.939
Ear Falls DS	12.5	13.25	3.356	3.479	3.540	3.884
Ear Falls TS	115	132	3.084	3.360	3.523	3.939
Lac Seul CGS	115	132	3.084	3.360	3.523	3.939
Manitou Falls CGS	115	132	2.790	3.187	3.162	3.770
Perrault Falls DS	115	132	2.897	2.968	2.203	2.253
Pickle Lake CTS	115	132	1.903	1.943	2.390	2.483
Red Lake CSS	115	132	1.419	1.446	1.634	1.683
Red Lake TS	115	132	1.372	1.397	1.642	1.692
Slate Falls DS	115	132	1.166	1.167	0.833	0.833
Esker CTS	115	132	0.676	0.743	0.378	0.388
Musselwhite CTS	115	132	0.686	0.759	0.384	0.394

Table B3: Short Circuit Levels – After Project Phase 1 AND Phase 2 I/S

Station / Bus	Bus Voltage (kV)	Max Voltage (kV)[6]	3-Φ Fault (kA)		L-G Fault (kA)	
			Symmetrical	Asymmetrical	Symmetrical	Asymmetrical
Major 115kV and 230kV Terminal Station Bus along Waasigan Route Corridor						
Dryden TS	115	132	7.156	8.019	8.645	9.978
Dryden TS	230	250	4.501	4.967	4.742	5.359
Lakehead TS	115	132	16.391	18.681	18.437	21.976
Lakehead TS	230	250	8.121	9.282	8.320	9.937
Mackenzie TS	115	132	6.051	7.470	7.280	9.380
Mackenzie TS	230	250	7.190	8.322	7.109	8.377
230kV Connected Stations						
Atikokan CGS	230	250	6.092	7.872	6.681	8.947
Dinorwic CSS	230	250	4.310	4.615	3.595	3.724
Greenwich Lake Wind Farm CGS – M23L	230	250	3.885	4.204	3.871	4.367
Greenwich Lake Wind Farm CGS – M24L	230	250	3.880	4.194	3.870	4.360
Pickle Lake CTS	230	250	0.990	1.006	1.182	1.225
Rainy River Gold CTS	230	250	2.801	2.955	3.230	3.534
Vermilion Bay CTS	230	250	3.769	4.004	3.061	3.158
115kV Connected Stations						
Thunder Bay Sub-Region						
Alexander CGS – C1A	115	132	9.328	10.435	9.867	11.215
Alexander CGS – C2A	115	132	9.329	10.441	9.871	11.224
Alexander CGS – C3A	115	132	9.321	10.424	9.858	11.198
Alexander CGS – R9A	115	132	9.332	10.424	9.865	11.189
Birch TS	115	132	14.097	15.648	11.105	11.978
Cameron Falls CGS – C1A	115	132	8.373	9.127	8.676	9.492
Cameron Falls CGS – C2A	115	132	8.331	9.121	8.727	9.617
Cameron Falls CGS – C3A	115	132	8.275	8.973	8.577	9.239
Ft Williams TS – Q4B	115	132	11.368	12.699	9.050	9.794
Ft Williams TS – Q5B	115	132	10.379	11.446	7.802	8.193
Kraft CTS	115	132	8.795	9.829	6.417	6.618
Lac Des Iles Mine CTS	115	132	1.216	1.217	0.802	0.802
Murillo DS	115	132	6.676	6.837	4.055	4.153
Nipigon DS	115	132	4.791	4.821	3.448	3.452
Pine Portage CGS	115	132	7.479	8.661	7.917	9.665
Port Arthur TS #1 – T1	115	132	12.485	13.318	12.036	13.038
Port Arthur TS #1 – T2	115	132	12.367	13.213	11.959	12.976
Red Rock DS	115	132	3.930	3.935	2.721	2.723
Silver Falls CGS	115	132	3.412	3.743	3.513	4.104
Thunder Bay CTS	115	132	10.662	13.068	10.385	13.306
West of Thunder Bay Sub-Region						
Agimak DS – T2	115	132	1.921	1.924	1.124	1.125
Agimak DS – T1	115	132	1.929	1.932	1.129	1.130
Ainsworth CTS	115	132	2.045	2.055	2.240	2.289
Barwick TS	115	132	2.075	2.088	2.305	2.361
Burleigh DS	115	132	4.418	4.547	3.612	3.666
Caribou Falls CGS	115	132	3.961	4.622	4.362	5.439
Calm Lake CGS	115	132	2.181	2.351	2.057	2.212
Clearwater Bay DS	115	132	2.161	2.164	1.411	1.412

[6] Maximum allowable continuous voltage utilized for short circuit calculation.

Crilly DS	6.6	7	9.812	12.706	0.000	0.000
Domtar Dryden CTS	115	132	6.482	7.497	6.417	6.980
Eton DS	115	132	5.243	5.452	4.309	4.398
Fort Frances MTS	115	132	7.792	8.686	9.315	10.800
Keewatin DS	115	132	4.642	4.742	3.478	3.542
Kenora CGS	115	132	5.407	5.723	4.204	4.372
Kenora DS	115	132	6.118	6.582	5.194	5.442
Kenora MTS	115	132	5.812	6.195	4.832	5.012
Margach DS	115	132	4.947	5.138	3.787	3.853
Mattabi CTS	115	132	1.048	1.050	0.580	0.580
Minaki DS	115	132	4.347	4.557	3.471	3.633
Moose Lake TS	115	132	5.250	5.647	5.088	5.475
Nestor Falls DS	115	132	2.852	2.869	1.911	1.912
Norman CGS	115	132	5.378	5.684	4.167	4.322
Sam Lake DS	115	132	1.652	1.668	0.942	0.960
Sapawe DS	115	132	3.301	3.367	2.313	2.356
Shabaqua DS	115	132	3.116	3.144	1.772	1.798
Sioux Narrows DS	115	132	2.986	3.020	1.882	1.885
Sturgeon Falls CGS	115	132	2.135	2.321	1.997	2.235
Valerie Falls CGS	115	132	4.079	4.296	3.357	3.499
Valora DS	115	132	1.211	1.212	0.676	0.677
Vermilion Bay DS	115	132	3.713	3.771	2.447	2.454
Weyerhaeuser Kenora CTS	115	132	5.748	6.214	6.464	7.211
Whitedog CGS	115	132	4.926	5.645	5.213	6.416
Whitedog DS	13.8	14.6	33.539	37.021	28.627	36.348
North of Dryden Sub-Region						
Balmer CTS	115	132	1.306	1.331	1.359	1.391
Cat Lake MTS	115	132	1.025	1.026	0.740	0.741
Crow River DS	115	132	1.945	1.985	2.423	2.513
Ear Falls CGS	115	132	3.112	3.387	3.547	3.963
Ear Falls DS	12.5	13.25	3.360	3.483	3.543	3.887
Ear Falls TS	115	132	3.112	3.387	3.547	3.963
Lac Seul CGS	115	132	3.112	3.387	3.547	3.963
Manitou Falls CGS	115	132	2.807	3.204	3.177	3.785
Perrault Falls DS	115	132	2.930	3.000	2.215	2.265
Pickle Lake CTS	115	132	1.954	1.994	2.445	2.538
Red Lake CSS	115	132	1.425	1.451	1.639	1.688
Red Lake TS	115	132	1.378	1.402	1.647	1.697
Slate Falls DS	115	132	1.176	1.177	0.836	0.837
Esker CTS	115	132	0.681	0.748	0.379	0.389
Musselwhite CTS	115	132	0.691	0.764	0.385	0.395

7.0 Appendix C

Table C1 below shows area bus voltage profiles before and after the incorporation of the Project Phase 1 and Phase 2.

The area generation assumptions and area load forecast used in the study were taken from the System Impact Assessment (SIA) report for the Waasigan Transmission Line Project (CAA ID 2022-732).

Table C1 indicates that all voltages are within pre-contingency limits.

Tables C2 and C3 show area bus voltage profiles before and after N-1 and N-2 contingencies with the incorporation of the Project Phase 1 and Phase 2. Results indicate all voltages are within pre- and post-contingency limits.

Table C11: Load Flow Study - Bus Voltage Profiles

Bus / Station	Bus Voltage (kV)	2022-2023 Winter Base Case – 2033 Load Forecast Without Waasigan Project I/S	2022-2023 Winter Base Case – 2035 Load Forecast with Waasigan Phase 1 I/S ONLY	2022-2023 Winter Base Case – 2037 Load Forecast with Both Waasigan Phase 1 AND Phase 2 I/S
Major 115kV and 230kV Terminal Station Bus along Waasigan Route Corridor				
Dryden TS	115	122.58	122.73	124.62
Dryden TS	230	240.18	240.34	244.83
Lakehead TS	115	123.44	123.40	123.59
Lakehead TS	230	244.20	245.79	246.47
Mackenzie TS	115	122.69	121.28	122.33
Mackenzie TS	230	244.83	246.02	248.39
230kV Connected Stations				
Greenwich Lake Wind Farm CGS	230	245.61	246.67	247.05
Atikokan CGS	230	244.88	246.08	248.44
Rainy River Gold CTS	230	243.96	243.76	246.05
Vermilion Bay CTS	230	242.63	242.56	245.87
Dinorwic CSS	230	240.40	240.70	245.02
Pickle Lake CTS	230	231.76	231.91	235.38
115kV Connected Stations				
Thunder Bay Sub-Region				
Alexander CGS	115	125.55	125.54	125.58
Birch TS	115	121.91	121.74	121.89
Cameron Falls CGS	115	125.56	125.56	125.60
Ft Williams TS	115	121.07	120.87	121.00
Kraft CTS	115	120.85	120.67	120.79
Lac Des Iles Mine CTS	115	123.72	123.63	123.79
Murillo DS	115	121.46	121.28	121.49
Nipigon DS	115	124.80	124.81	124.86
Pine Portage CGS	115	125.73	125.72	125.77
Port Arthur TS #1	115	122.90	122.81	122.99

Red Rock DS	115	124.67	124.69	124.74
Silver Falls CGS	115	126.54	126.48	126.59
Thunder Bay CTS	115	120.75	120.58	120.70
West of Thunder Bay Sub-Region				
Agimak DS	115	122.30	121.68	123.38
Ainsworth CTS	115	115.28	118.07	118.86
Barwick TS	115	115.32	118.10	118.89
Burleigh DS	115	121.43	121.23	122.16
Caribou Falls CGS	115	129.95	129.77	130.05
Calm Lake CGS	115	122.97	121.99	122.88
Clearwater Bay DS	115	121.81	121.08	121.88
Crilly DS	6.6	6.85	6.85	6.85
Domtar Dryden CTS	115	122.55	122.69	124.51
Dryden TS	115	122.58	122.73	124.62
Eton DS	115	122.53	122.59	124.38
Fort Frances MTS	115	121.66	121.49	122.41
Keewatin DS	115	122.65	122.08	122.88
Kenora CGS	115	123.00	122.47	123.29
Kenora DS	115	122.96	122.45	123.25
Kenora MTS	115	122.89	122.37	123.17
Margach DS	115	122.47	121.82	122.62
Mattabi CTS	115	122.56	121.92	123.63
Minaki DS	115	125.92	125.55	126.12
Moose Lake TS	115	122.57	121.40	122.49
Nestor Falls DS	115	120.49	120.80	121.65
Norman CGS	115	123.06	122.54	123.34
Sam Lake DS	115	117.10	118.61	120.62
Sapawe DS	115	122.17	121.23	122.21
Shabaqua DS	115	121.49	121.26	121.70
Sioux Narrows DS	115	121.31	121.12	121.95
Sturgeon Falls CGS	115	122.96	122.01	122.87
Valerie Falls CGS	115	122.83	121.71	122.75
Valora DS	115	122.56	121.92	123.63
Vermilion Bay DS	115	122.67	122.58	124.13
Weyerhaeuser Kenora CTS	115	122.11	121.75	122.66
Whitedog CGS	115	127.97	127.71	128.11
Whitedog DS	13.8	13.80	13.80	13.80
North of Dryden Sub-Region				
Balmer CTS	115	117.65	117.47	117.77
Cat Lake MTS	115	124.03	124.08	125.90
Crow River DS	115	122.80	122.87	124.64
Ear Falls CGS	115	122.47	122.45	122.86
Ear Falls DS	12.5	13.12	13.13	13.17

Ear Falls TS	115	122.47	122.45	122.86
Lac Seul CGS	115	122.47	122.45	122.86
Manitou Falls CGS	115	124.38	124.37	124.59
Perrault Falls DS	115	122.51	122.54	123.42
Pickle Lake CTS	115	122.80	122.88	124.40
Red Lake CSS	115	117.90	117.72	118.02
Red Lake TS	115	117.98	117.81	118.09
Slate Falls DS	115	124.44	124.48	126.31
Esker CTS	115	119.24	119.25	119.64
Musselwhite CTS	115	119.26	119.27	119.68

Table C2: N-1 Contingency Analysis

Bus / Station	Bus Voltage (kV)	2022-2023 Winter Base Case – 2037 Load Forecast with Waasigan Phase 1 AND Phase 2 I/S	Loss of 230kV A21L – Pre-ULTC	Loss of 230kV A21L – Post-ULTC
Major 115kV and 230kV Terminal Station Bus along Waasigan Route Corridor				
Dryden TS	115	124.62	123.96	123.98
Dryden TS	230	244.83	243.11	243.14
Lakehead TS	115	123.59	122.89	122.89
Lakehead TS	230	246.47	244.24	244.24
Mackenzie TS	115	122.33	120.99	121.00
Mackenzie TS	230	248.39	245.38	245.39
230kV Connected Stations				
Greenwich Lake Wind Farm CGS	230	247.05	245.43	245.43
Atikokan CGS	230	248.44	245.43	245.45
Rainy River Gold CTS	230	246.05	244.51	244.52
Vermilion Bay CTS	230	245.87	244.48	244.51
Dinorwic CSS	230	245.02	243.03	243.06
Pickle Lake CTS	230	235.38	233.77	233.79
115kV Connected Stations				
Thunder Bay Sub-Region				
Alexander CGS	115	125.58	125.36	125.36
Birch TS	115	121.89	121.26	121.26
Cameron Falls CGS	115	125.60	125.38	125.38
Ft Williams TS	115	121.00	120.42	120.43
Kraft CTS	115	120.79	120.23	120.23
Lac Des Iles Mine CTS	115	123.79	123.18	123.19
Murillo DS	115	121.49	120.82	120.82
Nipigon DS	115	124.86	124.57	124.58
Pine Portage CGS	115	125.77	125.53	125.54
Port Arthur TS #1	115	122.99	122.32	122.32
Red Rock DS	115	124.74	124.45	124.45
Silver Falls CGS	115	126.59	126.18	126.18
Thunder Bay CTS	115	120.70	120.19	120.19
West of Thunder Bay Sub-Region				
Agimak DS	115	123.38	122.39	122.41
Ainsworth CTS	115	118.86	118.03	118.03
Barwick TS	115	118.89	118.06	118.07
Burleigh DS	115	122.16	121.36	121.37
Caribou Falls CGS	115	130.05	129.90	129.90
Calm Lake CGS	115	122.88	121.87	121.87
Clearwater Bay DS	115	121.88	121.45	121.46
Crilly DS	6.6	6.85	6.85	6.85

Domtar Dryden CTS	115	124.51	123.91	123.93
Dryden TS	115	124.62	123.96	123.98
Eton DS	115	124.38	123.74	123.76
Fort Frances MTS	115	122.41	121.62	121.63
Keewatin DS	115	122.88	122.46	122.46
Kenora CGS	115	123.29	122.87	122.88
Kenora DS	115	123.25	122.83	122.84
Kenora MTS	115	123.17	122.75	122.76
Margach DS	115	122.62	122.18	122.18
Mattabi CTS	115	123.63	122.63	122.65
Minaki DS	115	126.12	125.82	125.83
Moose Lake TS	115	122.49	121.25	121.26
Nestor Falls DS	115	121.65	120.97	120.97
Norman CGS	115	123.34	122.92	122.93
Sam Lake DS	115	120.62	119.81	119.94
Sapawe DS	115	122.21	121.01	121.02
Shabaqua DS	115	121.70	120.83	120.83
Sioux Narrows DS	115	121.95	121.37	121.38
Sturgeon Falls CGS	115	122.87	121.89	121.90
Valerie Falls CGS	115	122.75	121.57	121.58
Valora DS	115	123.63	122.63	122.65
Vermilion Bay DS	115	124.13	123.54	123.56
Weyerhaeuser Kenora CTS	115	122.66	122.20	122.21
Whitedog CGS	115	128.11	127.90	127.90
Whitedog DS	13.8	13.80	13.80	13.80
North of Dryden Sub-Region				
Balmer CTS	115	117.77	117.49	117.50
Cat Lake MTS	115	125.90	125.04	125.06
Crow River DS	115	124.64	123.82	123.83
Ear Falls CGS	115	122.86	122.66	122.67
Ear Falls DS	12.5	13.17	13.15	13.15
Ear Falls TS	115	122.86	122.66	122.67
Lac Seul CGS	115	122.86	122.66	122.67
Manitou Falls CGS	115	124.59	124.48	124.49
Perrault Falls DS	115	123.42	123.07	123.08
Pickle Lake CTS	115	124.40	123.82	123.84
Red Lake CSS	115	118.02	117.73	117.74
Red Lake TS	115	118.09	117.81	117.82
Slate Falls DS	115	126.31	125.45	125.46
Esker CTS	115	119.64	119.46	119.46
Musselwhite CTS	115	119.68	119.49	119.50

Table C3: N-2 Contingency Analysis

Bus / Station	Bus Voltage (kV)	2022-2023 Winter Base Case – 2037 Load Forecast with Waasigan Phase 1 AND Phase 2 I/S	Simultaneous Loss of 230kV A21L & A22L – Pre-ULTC	Simultaneous Loss of 230kV A21L & A22L – Post-ULTC
Major 115kV and 230kV Terminal Station Bus along Waasigan Route Corridor				
Dryden TS	115	124.62	123.16	123.24
Dryden TS	230	244.83	241.43	241.53
Lakehead TS	115	123.59	123.79	123.78
Lakehead TS	230	246.47	244.20	244.20
Mackenzie TS	115	122.33	119.81	119.84
Mackenzie TS	230	248.39	242.82	242.87
230kV Connected Stations				
Greenwich Lake Wind Farm CGS	230	247.05	245.52	245.52
Atikokan CGS	230	248.44	242.87	242.93
Rainy River Gold CTS	230	246.05	243.15	243.21
Vermilion Bay CTS	230	245.87	243.15	243.23
Dinorwic CSS	230	245.02	241.18	241.27
Pickle Lake CTS	230	235.38	232.27	232.34
115kV Connected Stations				
Thunder Bay Sub-Region				
Alexander CGS	115	125.58	125.64	125.64
Birch TS	115	121.89	121.97	121.96
Cameron Falls CGS	115	125.60	125.65	125.67
Ft Williams TS	115	121.00	121.07	121.07
Kraft CTS	115	120.79	120.86	120.86
Lac Des Iles Mine CTS	115	123.79	123.94	123.94
Murillo DS	115	121.49	121.30	121.30
Nipigon DS	115	124.86	124.93	124.93
Pine Portage CGS	115	125.77	125.84	125.83
Port Arthur TS #1	115	122.99	123.15	123.15
Red Rock DS	115	124.74	124.81	124.81
Silver Falls CGS	115	126.59	126.69	126.68
Thunder Bay CTS	115	120.70	120.76	120.76
West of Thunder Bay Sub-Region				
Agimak DS	115	123.38	121.40	121.46
Ainsworth CTS	115	118.86	117.27	117.30
Barwick TS	115	118.89	117.31	117.33
Burleigh DS	115	122.16	120.64	120.67
Caribou Falls CGS	115	130.05	129.76	129.77
Calm Lake CGS	115	122.88	120.97	121.00
Clearwater Bay DS	115	121.88	121.03	121.06

Crilly DS	6.6	6.85	6.85	6.85
Domtar Dryden CTS	115	124.51	123.12	123.20
Dryden TS	115	124.62	123.16	123.24
Eton DS	115	124.38	122.98	123.05
Fort Frances MTS	115	122.41	120.91	120.93
Keewatin DS	115	122.88	122.04	122.07
Kenora CGS	115	123.29	122.46	122.48
Kenora DS	115	123.25	122.42	122.45
Kenora MTS	115	123.17	122.34	122.36
Margach DS	115	122.62	121.74	121.77
Mattabi CTS	115	123.63	121.64	121.69
Minaki DS	115	126.12	125.53	125.55
Moose Lake TS	115	122.49	120.18	120.21
Nestor Falls DS	115	121.65	120.34	120.36
Norman CGS	115	123.34	122.51	122.54
Sam Lake DS	115	120.62	118.82	119.13
Sapawe DS	115	122.21	120.05	120.08
Shabaqua DS	115	121.70	120.80	120.80
Sioux Narrows DS	115	121.95	120.84	120.86
Sturgeon Falls CGS	115	122.87	121.03	121.05
Valerie Falls CGS	115	122.75	120.53	120.56
Valora DS	115	123.63	121.64	121.70
Vermilion Bay DS	115	124.13	122.87	122.93
Weyerhaeuser Kenora CTS	115	122.66	121.77	121.80
Whitedog CGS	115	128.11	127.69	127.70
Whitedog DS	13.8	13.80	13.80	13.80
North of Dryden Sub-Region				
Balmer CTS	115	117.77	117.14	117.17
Cat Lake MTS	115	125.90	124.25	124.29
Crow River DS	115	124.64	123.05	123.09
Ear Falls CGS	115	122.86	122.42	122.44
Ear Falls DS	12.5	13.17	13.12	13.12
Ear Falls TS	115	122.86	122.42	122.44
Lac Seul CGS	115	122.86	122.42	122.44
Manitou Falls CGS	115	124.59	124.35	124.36
Perrault Falls DS	115	123.42	122.65	122.69
Pickle Lake CTS	115	124.40	123.06	123.10
Red Lake CSS	115	118.02	117.39	117.43
Red Lake TS	115	118.09	117.46	117.50
Slate Falls DS	115	126.31	124.64	124.68
Esker CTS	115	119.64	119.29	119.30
Musselwhite CTS	115	119.68	119.31	119.32

REGIONAL AND BULK PLANNING

The most recent regional planning report in support of this Project is provided in **Exhibit H, Tab 1, Schedule 1, Attachment 1**, titled the *Integrated Regional Resource Plan - Northwest Region* (issued January 2023). This IRRP supports the IESO's prior recommendation of the need for the Waasigan Project Phases 1, and the anticipated need for Phase 2.

Subsequent to issuing this IRRP, the IESO provided Hydro One further direction and support regarding the need and in-service timing for Phase 2. That subsequent direction, in the form of an IESO letter, dated April 24, 2023, is provided in this Application's Need Evidence, specifically at **Exhibit B, Tab 3, Schedule 1, Attachment 8.**

On July 26, 2023, the IESO provided Hydro One with an additional report supporting the Project's need. That report is filed with the *Need Evidence* at **Exhibit B, Tab 3, Schedule 1, Attachment 9.**

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INTEGRATED REGIONAL RESOURCE PLAN - NORTHWEST REGION – (JANUARY 2023)

Integrated Regional Resource Plan

Northwest Region
January 2023

Connecting Today.
Powering Tomorrow.

Disclaimer

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List of Acronyms

Acronym	Definition
APS	Achievable Potential Study
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
LDC	Local Distribution Company
LTE	Long-term Emergency
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NWA	Non-wires Alternative
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SCGT	Simple Cycle Gas Turbine
TS	Transformer Station
ULTC	Under-Load Tap Changer

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

This IRRP was prepared on behalf of the Technical Working Group (Working Group) of the Northwest region which included the following members:

Independent Electricity System Operator (IESO)

Hydro One Networks Inc. (Hydro One Transmission)

Hydro One Networks Inc. (Hydro One Distribution)

Atikokan Hydro Inc.

Fort Frances Power Corporation

Sioux Lookout Hydro Inc.

Synergy North

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

The Northwest Working Group members agree with the Integrated Regional Resource Plan (IRRP)'s recommendations and support the implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community consultations. The Northwest Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

1. Introduction

This Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Northwest region over the next 20 years from 2021 to 2040. The Northwest region includes the area roughly bounded by Lake Superior to the south, the Marathon area to the east, and the Manitoba border to the west. It includes the districts of Kenora, Rainy River and Thunder Bay. A geographic map of the Northwest region is shown in Figure 1-1. Note that, for regional electricity planning purposes, the region is defined by electrical infrastructure rather than geography. The region encompasses the 230 kV circuits from the Manitoba interties in the west to Marathon TS in the east as well as the 115 kV sub-systems in between. A single line diagram of the electrical infrastructure in the region is shown in Figure 1-2.

Northwest regional electricity demand is winter peaking and, over the last five years, has grown on average by 1.1% per year. Electricity supply to the Northwest region is provided through the 230 kV East-West Tie circuits from Wawa TS, as well as from interconnections with Manitoba and Minnesota. Local generation in the region is predominantly hydroelectric and biomass-fueled.

The region's electricity is delivered by five local distribution companies (LDCs): Hydro One Networks Inc., Atikokan Hydro Inc., Fort Frances Power Corporation, Sioux Lookout Hydro Inc., and Synergy North. Hydro One Networks is also the lead transmitter in the region for regional planning purposes. Note that three transmitters own assets in the Northwest region: Hydro One Networks, Nextbridge Infrastructure, and Wataynikaneyap Power. As the lead transmitter, Hydro One Networks coordinates the involvement of other transmitters as necessary. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Working Group composed of the aforementioned LDCs and Hydro One Networks.

Development of the Northwest IRRP was initiated in Jan 2021 following the publication of the Needs Assessment report in July 2020 by Hydro One and the Scoping Assessment Outcome Report in Jan 2021 by the IESO.[1] The Scoping Assessment identified needs that should be further assessed through an IRRP. The Working Group was then formed to gather data, identify near- to long-term needs in the region and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;

[1] The Needs Assessment can found on Hydro One's Northwest Ontario regional planning website and the Scoping Assessment Outcome Report can be found on the IESO's Northwest regional planning engagement website.

- Demand forecast scenarios, distributed generation assumptions, and conservation and demand management are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- An update on the Supply to the Ring of Fire study is provided in Section 8
- A summary of engagement to date and the next steps are provided in Section 9; and
- The conclusion is provided in Section 10

Figure 1-1 | Geographic Map of the Northwest Region

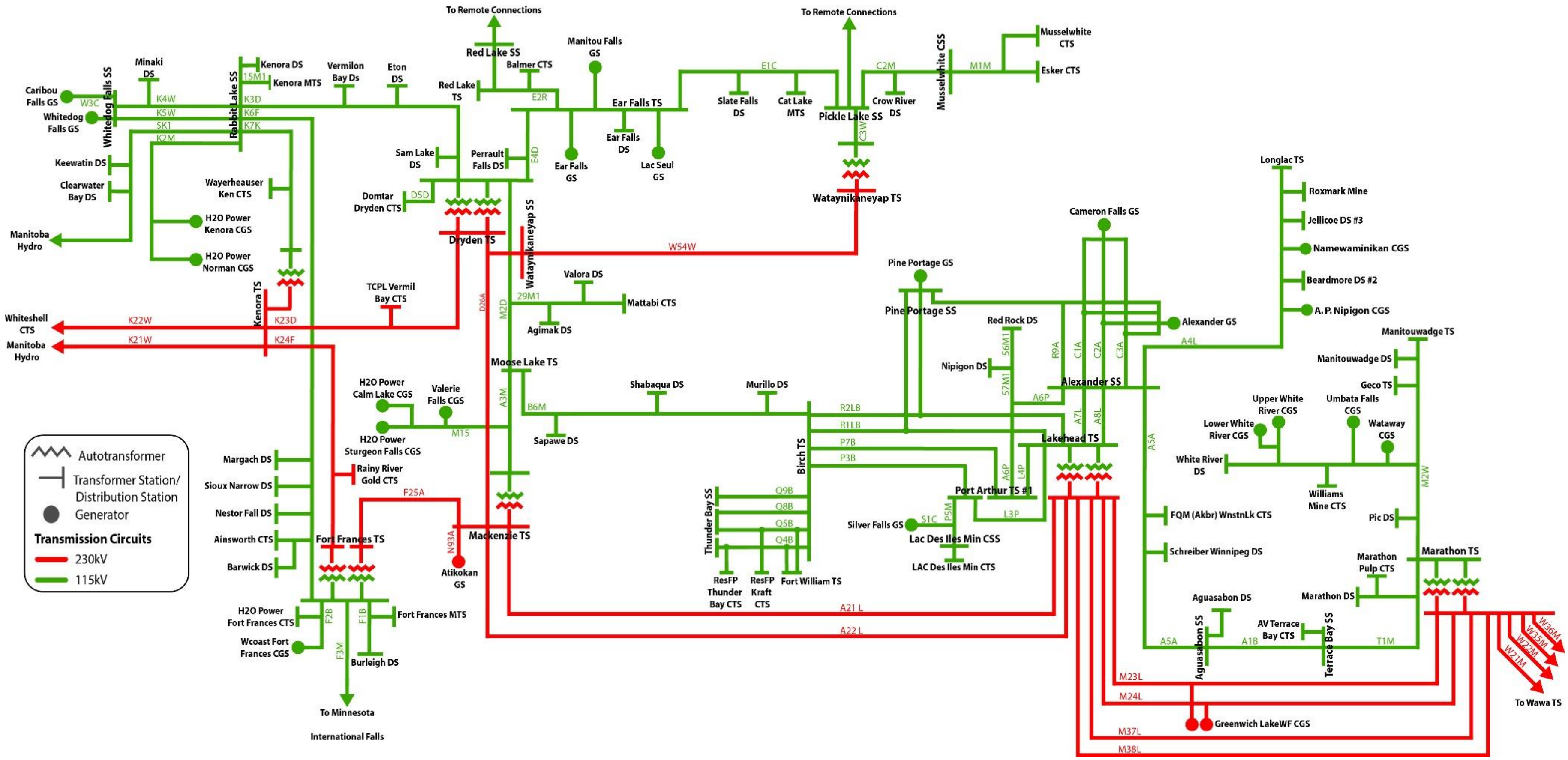

Figure 1-2 | Electricity Infrastructure in the Northwest Ontario Region

2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Northwest 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 the application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC). The IRRP's recommendations are informed by an evaluation of options, representing alternative ways to meet the needs, that consider: reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic and feasible), and feedback from stakeholders.

There are several recent or ongoing transmission reinforcement projects in the Northwest region including the:

- East-West Tie Reinforcement (new double circuit 230 kV line from Wawa TS to Marathon TS and from Marathon TS to Lakehead TS),
- Waasigan Transmission Line Project (Phase 1 being a new double circuit 230 kV line from Lakehead TS to Mackenzie TS and Phase 2 being a new single circuit 230 kV line from Mackenzie TS to Dryden TS), and
- Wataynikaneyap Transmission Project (new single circuit 230 kV line from Dinorwic Junction near Dryden to Wataynikaneyap TS near Pickle Lake as well as 115 kV remote connection circuits north of Pickle Lake and Red Lake).

Taken together, these projects reinforce many of the 230 kV transmission paths in the region. With these reinforcement projects, the infrastructure in the Northwest will be adequate to support forecast growth except for some station capacity and local operational needs. There are no new transmission projects recommended as a result of this Northwest planning initiative.

Northwest electricity demand growth is driven by the mining sector which tends to add large incremental blocks of load, often with short lead times. Therefore, this IRRP also studied several high growth sensitivities beyond forecast demand levels to test the robustness of the plan.

The plan below is organized into two sections: near-/medium-term recommendations and ongoing monitoring. Near-/medium-term recommendations include actions or further studies to be undertaken by Working Group member(s) by a specified date. These recommendations address needs with a high level of forecast certainty and requires firm commitments in this cycle of regional planning. Ongoing monitoring activities address long-term needs or potential needs flagged in high growth sensitivities that may emerge but are not yet certain based on the latest electricity demand forecast. This approach ensures that the IRRP provides clear guidance on investments needed in the near future while remaining flexible to consider new information such as electrification, energy efficiency, and industrial/mining development plans.

2.1 Near-/Medium-Term Recommendations

The near- and medium-term recommendations are summarized in Table 2-1 and further discussed below.

Table 2-1 | Summary of Near- and Medium-Term Recommendations

Need/Subsystem	Recommendation	Lead Responsibility	Required By
Kenora MTS Station Capacity	Non-wires alternatives (NWAs) can be cost effective depending on distribution system benefits; Kenora MTS will be a potential focus area for the IESO's Local Initiative Program and Synergy North will lead further non-wires analysis in local planning	Synergy North; IESO	2029
Crilly DS Station Capacity	NWAs not suitable; Hydro One Distribution will refine options for refurbishment or a new station in local planning	Hydro One Distribution	2027
Margach DS Station Capacity	NWAs not suitable; Hydro One Dx will install fan monitoring if growth materializes and monitor for additional growth that might necessitate a second transformer	Hydro One Distribution	2023
Fort Frances MTS Customer Reliability	Reconfiguration of Fort Frances TS to reduce supply interruptions to Fort Frances MTS during transmission system outages; Fort Frances Power and Hydro One Transmission will refine configuration in local planning	Fort Frances Power; Hydro One Transmission	As Soon as Practical
E1C Operation and High Voltage	With the new W54W circuit in-service, part of the Wataynikaneyap Transmission Project, E1C will be operated "normally open" and additional reactors will be installed at/near Pickle Lake SS to manage high voltages; Hydro One and IESO will collaborate in the Regional Infrastructure Plan to refine location of open point and reactor sizing	IESO Hydro One Transmission	As Soon as Practical

Note that all costs discussed below are planning-level estimates (-50% to +100%) provided for the purpose of comparing options. Material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs.

2.1.1 Kenora MTS Station Capacity

Kenora MTS is expected to reach capacity in 2029. There are no upstream supply constraints aside from the station capacity itself. The "wires" options range from installing an additional transformer at the existing station ($5M) to a new station across town ($30M) that would also incrementally improve reliability and provide distribution system benefits.[2] The wires options and distribution benefits are further discussed in Section 7.1.4.1. Based on the forecast hourly demand and associated energy-not-served profiles, three non-wires alternatives (NWAs) were identified including a 4 MW gas turbine facility, a 6-hour 4 MW battery, and a hybrid option of energy efficiency and demand response. The cost of these NWAs generally falls between the cost of expanding the existing station and a new station.[2] Therefore, the decision to pursue NWAs versus traditional wires options rests on distribution system benefits that can be realized by each option. NWA options analysis is further discussed in Section 7.1.4.2.

The technologies, regulatory framework, and protocols required to implement dispatchable NWAs to meet local capacity needs are still being tested. The IESO's York Region Non-Wires Alternative Demonstration Project[3] is currently exploring market-based approaches to secure energy and capacity services from distributed energy resources (DERs) for local needs. There is a window of opportunity between today and 2029 when the Kenora MTS capacity need arises to leverage learnings from the York Pilot and further refine NWAs for Kenora MTS.

Therefore, the IRRP recommends that Synergy North lead further NWA analysis and refinement as part of local planning. Synergy North should monitor load growth at Kenora MTS to determine when a firm commitment for additional capacity is required and implement NWAs if they remain feasible and cost-effective. Furthermore, the IESO will consider Kenora MTS as a potential focus area for the Local Initiatives Program[4] under the 2021-2024 Conservation and Demand Management Framework. The IESO will collaborate with Synergy North in 2023 as further details for the next round of the Local Initiatives Program becomes available.

2.1.2 Crilly DS Station Capacity

Crilly DS is expected to reach capacity in 2027. Crilly DS is a small (~2.2 MW) station supplied from a bus shared with Sturgeon Falls CGS, a small hydroelectric plant approximately 50 km west of Atikokan. This is a non-standard supply arrangement that results in annual outages to

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[2] The methodology for calculating cost estimates is set out in Section 7.1.1

[3] For more information on the pilot and latest developments, please see the York Region Non Wires Alternatives Demonstration Project engagement webpage.

[4] For more information on the Local Initiatives Program, please see the Save ON Energy Local Initiatives webpage and the 2021-2024 Conservation and Demand Management Framework webpage.

Crilly DS when the generator is undergoing maintenance. Diesel generation is currently used for backup power when Sturgeon Falls is on outage. Furthermore, station equipment is nearing end-of-life and space constraints limit in situ refurbishment options.

Non-wires alternatives are not suitable for Crilly DS due to the existing reliance on backup generation. Distributed energy resources cannot remove the reliance on backup power and provide reliability comparable with other standard supply arrangements. Furthermore, the pool of customers served at Crilly DS is too small to target demand-modifying solutions such as energy efficiency and demand response. The IRRP recommends that Hydro One Distribution conducts local planning, in coordination with the Regional Infrastructure Plan, to refine refurbishment/new station options identified in the IRRP with the goal of balancing reliability improvements and cost. Options considered thus far include:

- Refurbish Crilly DS at its current location (and continue to rely on backup power during outages),
- Rebuild Crilly DS at a different location as a 115/25 kV HVDS,
- Rebuild Crilly DS at a different location as a 230/25 kV HVDS, or
- Replace Crilly DS with a 115:25 kV padmount transformer (transformer enclosed in a grounded cabinet that can be accommodated outside the existing station fence).

Wires options for Crilly DS and the rationale for not pursuing non-wires alternatives are further discussed in Section 7.1.2. Hydro One Distribution should monitor load growth to determine when a firm commitment to refurbish/rebuild Crilly DS is required.

2.1.3 Margach Station Capacity

Margach DS is expected to reach capacity in 2023 due to a large existing industrial customer seeking to be resupplied at Margach DS from a nearby CTS. Margach DS is approximately 10 km east of Kenora. Non-wires alternatives are not capable of addressing this large near-term step increase in demand.

The IRRP recommends that Hydro One distribution install transformer fan monitoring which will increase the station capacity above forecast demand levels. If additional capacity needs arise, a second transformer at the station which currently acts as a spare can be brought into service but no recommendation beyond the fan monitoring is required today. Wires options for Margach DS and the rationale for not pursuing non-wires alternatives are further discussed in Section 7.1.3.

2.1.4 Fort Frances MTS Customer Reliability

Fort Frances MTS, a step-down transformer station that supplies LDC loads in Fort Frances, is supplied from the nearby Fort Frances TS. The two stations are located immediately across the street from each other. Fort Frances TS is configured in a manner that would result in Fort Frances MTS supply interruptions during certain transmission outages. Fort Frances MTS station equipment is also aging with both transformers and most breakers dating from the 1960s and 1970s. While the station equipment has not yet reached end-of-life, most equipment has reached or exceeded its typical useful life (as defined in the OEB's Asset Depreciation Study[5]) and will need to be replaced gradually over the next 10-15 years. While there is currently no firm station capacity need within the forecast horizon, several potential large customers have approached Fort Frances Power which could quickly use up the remaining station capacity. Furthermore, 115 kV breakers at Fort Frances TS are also approaching end of life around 2027 which presents an opportunity to reconfigure the station to minimize supply interruptions for Fort Frances MTS. Customer reliability, sustainment, and potential capacity needs are further discussed in Sections 6.2.2 and 0.

Fort Frances Power is developing a roadmap for Fort Frances MTS considering the replacement of aging assets, demand growth, and reliability improvements by reconfiguring supply from Fort Frances TS. Considering these needs simultaneously will ensure the most optimal and cost-effective outcome. Hydro One has proposed several Fort Frances TS reconfigurations that would incrementally improve customer reliability for Fort Frances TS and are further discussed in Section 7.2. The IRRP recommends that Fort Frances Power and Hydro One continue to collaborate and refine a configuration in local planning.

2.1.5 E1C Operation and High Voltage

With the new 230 kV Wataynikaneyap circuit W54W in-service, operating circuit E1C closed would result in a loop comprised of the E4D-E1C-W54W circuits. This arrangement would severely limit the transfer capability through E4D and W54W. The IRRP confirms that E1C should be operated normally open. This configuration is consistent with the 2015 North of Dryden IRRP.

With E1C operated normally open, high voltage arises due to line charging. Studies show that opening E1C closer to the Ear Falls TS end minimizes high voltage issues. Additionally, the IRRP recommends an additional reactor (approximately 10 MVar) at or near Pickle Lake SS.

E1C closed loop transfer limitations and E1C normally open high voltage issues are further discussed in Section 6.2.3. The IESO and Hydro One Transmission will collaborate in the Regional Infrastructure Plan to refine the location of the open point on E1C and the sizing of the reactor, considering asset conditions and costs.

[5] The OEB's Asset Depreciation Study can be found on the Ontario Energy Board's website.

2.2 Ongoing Monitoring

In addition to the needs addressed in the near- and medium-term plan above, there are several long-term or potential needs that may emerge over the forecast horizon. These needs will be monitored by the Working Group to determine when future planning studies should be triggered.

2.2.1 Station Capacity Needs Emerging in the Long-term

White Dog DS and Marathon DS are expected to reach capacity in 2032 and 2038 respectively. In both cases, current demand already exceeds 85% of the station capacity but forecast growth is modest over the forecast horizon. As with many stations across the Northwest, growth can materialize quickly if industrial development intensifies. Therefore, White Dog DS and Marathon DS should be monitored, and further planning activities should be triggered at least five years before anticipated capacity needs to enable consideration of non-wires alternatives. White Dog DS and Marathon DS station capacity needs are further discussed in Section 6.2.1.4 and 6.2.1.5.

2.2.2 Potential Growth in the Red Lake Area

The Red Lake area has significant mining activity and electricity demand is forecast to grow from 58 MW today to 70 MW by 2028. The W54W circuit recently completed as part of the Wataynikaneyap Transmission Project will help relieve constraints on the existing 115 kV circuits to Red Lake.

No capacity needs are anticipated based on the current demand forecast which was finalized by the end of 2021. However, the Working Group is aware of additional potential mining projects that are not captured in the current reference scenario demand forecast.[6] The timing and amount of load associated with these mines are not yet certain but, considering the typical size of new mining projects, remaining capacity in the Red Lake area can quickly be exhausted. Section 6.3.1 identifies the load meeting capability for the Red Lake area as well as constraints on the supply to Ear Falls and Dryden. Depending on the demand that materializes, bulk system enhancements beyond the scope of this IRRP (e.g., Waasigan Transmission Line Project Phase 2) may also be required.

The Working Group will monitor growth in the Red Lake area to determine when future planning activities should be triggered. The IESO will also continue to update the mining demand forecast, including mines in the Red Lake area, to inform ongoing bulk planning activities.

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[6] As described in Section 5.4, for the purpose of this IRRP, the mining sector demand forecast was finalized by the end of 2021. The Working Group is aware of additional future mining projects that were either brought to the awareness of the Working Group after 2021 or were not yet certain enough for inclusion in the demand forecast. The IESO is updating the mining sector demand forecast by end of Q1 2023 and will provide updates to the Working Group to inform the Regional Infrastructure Plan.

2.2.3 Potential Growth in the Fort Frances Area

Several large industrial customers have expressed interest in connecting in the Fort Frances area; these customers' potential loads are not included in the current demand forecast. While the incremental electricity demand associated with these customers (approximately totalling 100 MW) may be significant, no firm commitments have been made.

No supply capacity needs are anticipated based on the current demand forecast. Section 6.3.2 identifies the load meeting capability of the Fort Frances area. The Working Group will monitor growth in the Fort Frances area to determine when future planning activities should be triggered.

2.3 Coordination with ongoing Bulk Planning and Project Implementation Activities

In April 2022, as part of the IESO's obligation to recommend the specific scope and timing of the Waasigan Transmission Line Project, the IESO recommended a staged approach for construction with Phase 1 (a new line from Thunder Bay to Atikokan) being placed in-service as close to the end of 2025 as possible. The IESO will continue to monitor developments in the region, update the mining sector demand forecast and provide an update on the need for Phase 2 (a new line from Atikokan to Dryden) by Q2 2023.

The IESO is also conducting a Northern Ontario Voltage Study to identify reactive compensation needs across northern Ontario. There are several recently implemented or planned major transmission reinforcement projects in the north including the East-West Tie Reinforcement, Waasigan Transmission Line Project, Wataynikaneyap Transmission Project, and Northeast Bulk Plan recommendations.[7] These projects will impact the voltage characteristics across the northern bulk transmission system, including the Northwest region. The Northern Ontario Voltage Study is expected to be finalized in early 2023.

The Waasigan Transmission Line Project and Northern Ontario Voltage Study are further described in Section 4.2. The IESO will continue to update the Working Group regarding ongoing bulk planning and project implementation developments for consideration in the Regional Infrastructure Plan.

In addition to the plans above, the IESO is carrying out a Supply to the Ring of Fire study in parallel with this IRRP. The preliminary findings are discussed in Section 8. The Supply to the Ring of Fire Study will continue in 2023 and the IESO will update the working group on findings for consideration in future regional planning activities.

[7] The Need for Northeast Bulk System Reinforcements report can found on the Northeast Bulk Planning webpage.

3. Development of the Plan

3.1 Regional Planning Process

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

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

1. A Needs Assessment, led by the transmitter, 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, identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;

3. An Integrated Regional Resource Plan (IRRP), led by the IESO, proposes recommendations to meet the identified needs requiring coordinated planning; and/or

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

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

Regional planning is not the only type of electricity planning in Ontario. Other planning activities include bulk system planning, carried out by the IESO, and distribution system planning, carried out by LDCs. There are inherent overlaps in these three levels of electricity infrastructure planning.

The IESO completed a review of the regional planning process following the completion of the first cycle of regional planning for all 21 regions. The IESO's Regional Planning Process Review report is posted on the IESO's website. Implementation of Regional Planning Process Review recommendations by the IESO, Ontario Energy Board, and its Regional Planning Process Advisory Board are ongoing.

3.2 The Northwest Region and IRRP Development

The process to develop the Northwest IRRP was initiated in January 2021 following the publication of the Needs Assessment report in July 2020 by Hydro One and Scoping Assessment Outcome Report in January 2021 by the IESO. As per the 18-month timeline, triggered by the publication of the Scoping Assessment Outcome Report, the original publication date for the Northwest IRRP was scheduled for July 13, 2022.

In April 2022, the IESO wrote to the Ontario Energy Board (OEB) to provide notice that the IESO required an additional six months to complete the IRRP. The IRRP's original scope was expanded to include additional key developments in the Northwest region. The expanded scope enabled more extensive stakeholder engagement, consideration of additional growth sensitivities, and better alignment with ongoing bulk studies across the Northwest and Northeast regions. Based on the IESO's estimate of the additional time required to incorporate the expanded scope, the new expected posting date for the Northwest IRRP was extended to January 13, 2023.

4. Background and Study Scope

This is the second cycle of regional planning for the Northwest region. In the first cycle of regional planning, the region was divided into four sub-regions, each with its own IRRP:

- Greenstone-Marathon (published June 2016)
- Thunder Bay (published December 2016)
- West of Thunder Bay (published July 2016)
- North of Dryden (published January 2015)

A summary of each of the above IRRPs can be found in the 2021 Scoping Assessment Outcome Report[8]. The Scoping Assessment for this planning cycle recommended a single IRRP covering the entire Northwest region. This report presents an integrated regional electricity plan for the next 20-year period from 2021-2040.

Note that two new transmission system projects, the East-West Tie ("EWT") reinforcement and the Wataynikaneyap Transmission Project ("Watay Project") came into service during the current IRRP study. They were both assumed to be in-service for the purpose of this IRRP's technical assessments. The EWT reinforcement adds four new 230 kV circuits: M37L and M38L from Lakehead TS to Marathon TS and W35M and W36M from Marathon TS to Wawa TS. The new EWT circuits were placed in service in March 2022. The Wataty Project includes a new 230 kV circuit, W54W, between Wataty 230/115 kV TS and Dinorwic Junction on circuit D26A, which runs between Dryden TS and Mackenzie TS. W54W was placed in service in August 2022. The Wataty Project includes the connection of ten remote First Nation communities north of Pickle Lake (electrically supplied by Pickle Lake SS) and an additional seven remote First Nation communities north of Red Lake (electrically supplied by Red Lake SS). As of Q4 2022, work is still underway to connect Pickle Lake and Red Lake remote communities, but they were assumed to be in service for the purpose of this IRRP's technical assessments.

4.1 Study Scope

This IRRP identifies electricity needs in the Northwest Region and develops and recommends options to meet these needs. A list of transmission facilities included in the scope of this study can be found in Appendix C. The plan was prepared by the IESO on behalf of the Working Group. The plan includes consideration of forecast electricity demand growth, conservation, and demand management (CDM), distributed generation (DG), transmission and distribution system

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[8] The 2021 Scoping Assessment Outcome Report can be downloaded from the Northwest Regional Planning engagement webpage.

capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system.

The Northwest IRRP was developed by completing the following steps:

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

For the Northwest IRRP, areas of interest with high growth potential beyond forecast demand levels were identified through stakeholder engagement. Additional high sensitivity studies were performed for these areas to test the robustness of the system to supply higher than forecast demand.

4.1.1 Scope of Regional Planning Regarding New Connections

The purpose of the IRRP is to identify and address reliability needs that require coordination between transmitters, distribution companies, and the IESO. In the Northwest region, growth is driven in large part by industrial customers, predominantly in the mining sector. A subset of these customers are not currently connected to the electricity grid but are pursuing grid connection in the near term. The IRRP used the best available information to accurately simulate the connection arrangement of future customers and projects. However, IRRP technical studies were focused on evaluating the overall adequacy of regional infrastructure to supply forecast demand rather than the capability to supply any specific new project. The IRRP did not study the local connection requirements of any individual project unless there was an opportunity to align with broader regional needs.[9]

4.2 Parallel Bulk Planning Activities

The Waasigan Transmission Line Project and the Northern Ontario Voltage study are proceeding in parallel with this IRRP and the upcoming Regional Infrastructure Plan. Findings and recommendations from these bulk planning activities will inform ongoing regional planning activities.

4.2.1 Waasigan Transmission Line Project

The Waasigan Transmission Line Project ("Waasigan Project"), formally the Northwest Bulk Line, was identified in the Government's 2013 and 2017 Long Term Energy Plans (the "LTEPs") as a priority project to:

- Increase electricity supply to the region west of Thunder Bay;
- Provide a means for new customers and growing loads to be served with clean and renewable sources that comprise Ontario's supply mix; and,
- Enhance the potential for development and connection of renewable energy facilities.

The LTEPs divided the Waasigan Project into three phases:

- Phase 1 - a line from Thunder Bay to Atikokan;
- Phase 2 - a line from Atikokan to Dryden; and,
- Phase 3 - a line from Dryden to the Manitoba border through Kenora.

Following the 2013 LTEP, the Ontario Government issued an Order in Council, also in 2013, that amended Hydro One's license to develop and seek approval for the Waasigan Project according to the scope and timing specified by the IESO.

In 2018, the IESO recommended that Hydro One commence development work (i.e., complete the Environmental Assessment) for Phase 1 and Phase 2 based on the timing of projected supply capacity needs and the risk of them materializing earlier. The IESO committed to ongoing monitoring to determine when construction of both Phase 1 and Phase 2 should begin and to confirm that they are the best course of action to meet the needs.

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[9] Potential customers seeking connection should note that participation in the IRRP does not replace connection processes, namely Customer Impact Assessments (CIA) or System Impact Assessments (SIA). Furthermore, the absence of regional reliability needs identified through the IRRP in a particular area does not guarantee that connection requests in that area will be approved in a CIA or SIA.

In 2022, the IESO updated the demand forecast for the region west of Thunder Bay with information from the IRRP demand forecast and feedback from stakeholders. The mining sector demand forecast drove the majority of the demand growth and is further discussed in Section 5.4. The updated demand forecast showed a need for Phase 1 starting in 2025 and a temporary need for Phase 2 in 2026 and 2027, but not thereafter as some existing mining projects reach end of life. Therefore, the IESO recommended a staged approached for construction where Hydro One would construct the Project to meet near-term system capacity needs, with Phase 1 being placed in service as close to the end of 2025 as possible. The IESO will continue to monitor developments in the Region and provide an update in Q2 2023 on the expected need date for Phase 2. This is a balanced approach to accommodate growth in a timely manner while managing ratepayer risks.

The IESO recognizes that a firm need for Phase 2 could materialize quickly given the potential for additional growth in the region. The IESO is currently in the process of updating the mining demand forecast to reflect additional information received over the past year since the last forecast iteration and to better capture future growth driven by electrification trends and government policy. The forecast update is expected to be completed in Q1 2023.

4.2.2 Northern Ontario Voltage Study

The IESO is conducting a Northern Ontario Voltage Study to identify reactive compensation needs across the bulk system in northern Ontario. The Northern Ontario Voltage Study is expected to be finalized in early 2023.

4.3 Supply to the Ring of Fire

The Ring of Fire is a remote area approximately 500 km north of Thunder Bay rich in critical minerals but without grid power supply. The decision to pursue transmission supply to the Ring of Fire ultimately lies with mining companies and remote communities as they are the direct beneficiaries, or with the provincial and federal governments, to advance broader policy objectives.

Transmission supply to the Ring of Fire was contemplated in the 2015 cycle of regional planning. With renewed interest in developing the Ring of Fire from both government and mining companies, the IESO is updating its Supply to the Ring of Fire study in parallel with this IRRP to help inform government policy and potential customers seeking connection. This study outlines opportunities for alignment, updated high-level transmission supply cost estimates, updated avoided diesel system costs from connecting remote communities, and greenhouse gas reductions as a result of supplying remote communities and potential mines from the electricity grid instead of local generation. The preliminary findings are discussed in Section 8.

The study scope and timing of this ongoing study will evolve with government policy direction. The IESO will share updates with the Working Group to inform upcoming regional planning activities such as the Regional Infrastructure Plan.

5. Electricity Demand Forecast

This section describes the development of the demand forecast for the Northwest Region that underpins this IRRP. The 20-year forecast has three components:

- **Distribution-connected**: The distribution-connected forecast reflects demand served on the distribution systems in the Northwest and is based on information submitted by local distribution companies.

- **Transmission-connected**: The transmission-connected forecast reflects demand served directly from the transmission system. This is typically comprised of large industrial customers that have their own transformation station. The transmission-connected forecast is informed by direct engagement with customers.

- **Mining Sector**: The mining sector forecast captures electricity demand from both existing grid-connected and known future mining projects that are not yet grid-connected. The mining sector forecast is informed by data from government, industry publications, and engagement individual project proponents. Note that electricity demand from existing mining projects is also reflected in the above transmission- and distribution-connected forecast components. When the mining sector component is layered on top of the distribution-connected and transmission-connected components, only the contribution of new mining projects is shown to avoid double counting

Each forecast component is described in detail below. Note that the forecasts in this section refer to the non-coincident peak demand forecast (i.e., the sum of each station's individual peak demand). Coincident forecasts (i.e., contribution of each station to the overall peak demand hour) for the subsystem in question are used for the purpose of identifying need dates and options analysis in Section 6 and 7. Coincident forecasts are found by applying a coincidence factor based on the contribution of each station to the subsystem's coincident peak over the past five years.

Additional details related to the development of the demand forecast are provided in Appendix B. Though the Northwest IRRP forecast was created prior to October 2022, the Ontario Energy Board has also since published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.[10]

[10] The Load Forecast Guideline can be found on the Ontario Energy Board's website.

5.1 Historical Demand

Figure 5-1 shows the net and gross historical demand over the last five years in the Northwest region. Distribution-connected customer historically make up approximately 55% of peak demand with the remainder made up of transmission-connected customers. Growth has been steady over the last five years, with an average annual demand growth rate of 1.1% and Northwest demand hovering just over 800 MW from 2018 through 2020. Northwestern Ontario is winter peaking, with the peak demand hour for each year typically occurring on winter evenings between 7 p.m. And 11 p.m.

Existing distributed generation resources historically contributed approximately 10-15 MW during peak demand conditions. This contribution was added back into the net demand forecast to arrive at the gross demand forecast. The 2020 gross demand was used as the starting point for the forecast unless station-level adjustments were necessary to account for anomalous demand conditions on a case-by-case basis.

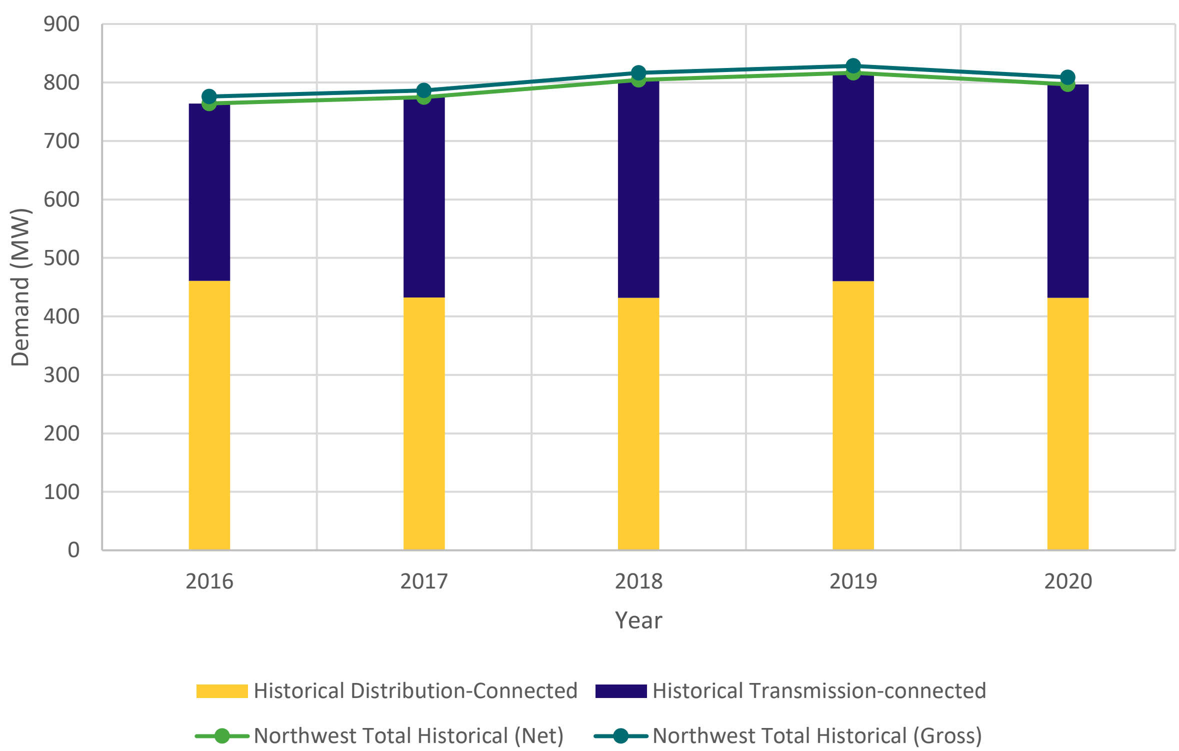

Figure 5-1 | 2016-2020 Historical Demand

5.2 Distribution-connected Forecast

The distribution-connected forecast component starts with a gross station-level demand forecast developed by local distribution companies for their service territory. The gross forecast was then modified to reflect the peak demand impacts of provincial conservation targets and distributed generation contracted through previous provincial programs such as FIT and microFIT[11] and adjusted to reflect extreme weather conditions to produce a reference scenario net forecast for planning assessments. Additional details related to the development of the distribution-connected demand forecast are provided in the sections below and in Appendix B.

5.2.1 Gross Local Distribution Company Forecast

Each participating local distribution company in the Northwest region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development and known connection applications within their service territories.

Note that the regional planning process relies on distributors to consider municipal and regional official plans and translate development plans into electrical demand forecasts. Distributors have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, and the municipalities they serve. More details on each distributor's demand forecast assumptions can be found in Appendix B.2 to B.6. Distributors 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 distributed generation or new conservation measures which are accounted for by the IESO, as discussed in Section 5.2.2 and 5.2.3 below.

The distribution-connected demand forecast compiled from distributors is adjusted to account for extreme weather conditions according to the methodology described in Appendix B.1. Figure 5-2 shows the total gross distribution-connected forecast for the Northwest region.

[11] More information about the Feed-in Tariff can be found on the IESO's website.

The distribution-connected demand forecast compiled from distributors is adjusted to account for extreme weather conditions according to the methodology described in Appendix B.1. Figure 5-2 shows the total gross distribution-connected forecast for the Northwest region.

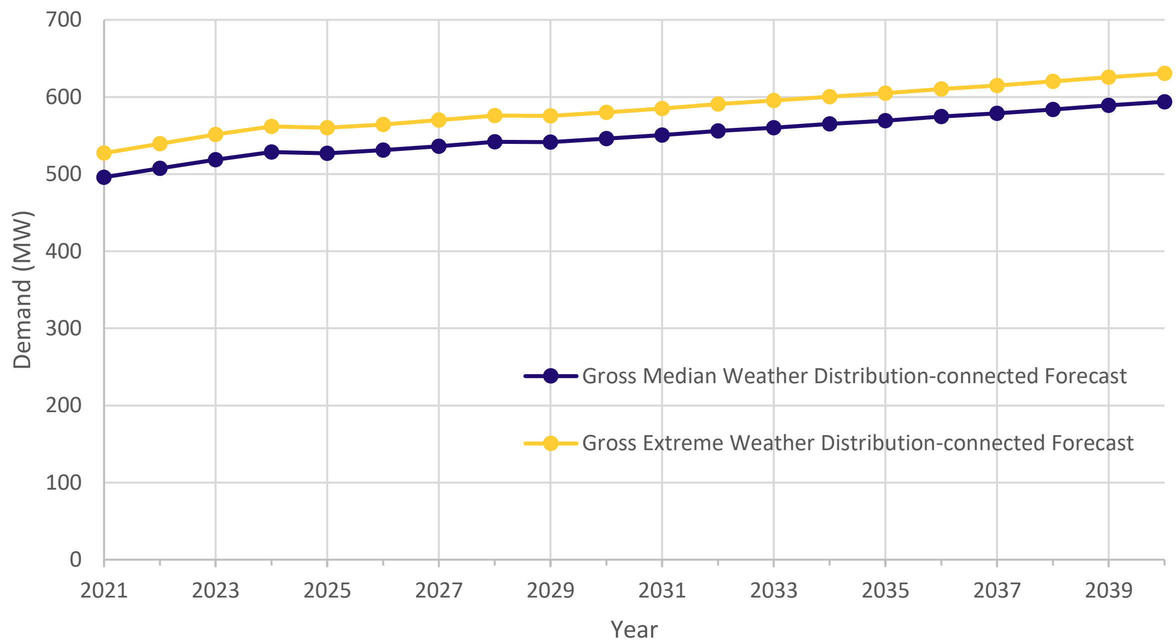

Figure 5-2 | Total Gross Median Weather Distribution-connected Forecast

5.2.2 Contribution of Conservation to the Forecast

CDM is a clean and cost-effective resource that helps meet Ontario's electricity needs and is an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and standards amendments as well as 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 new program-related activities account for Ontario programs, federal programs that result in electricity savings in Ontario, and forecast future energy efficiency programs. The 2021 – 2024 CDM Framework is the central piece in which the IESO delivers programs on a province-wide basis to enable Ontario's electricity consumers to improve the energy efficiency of their homes, businesses, institutions, and industrial facilities.

Figure 5-3 shows the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards and CDM programs) for residential, commercial, and industrial market segments. Additional details on the conservation forecast methodology are provided in Appendix B.9.

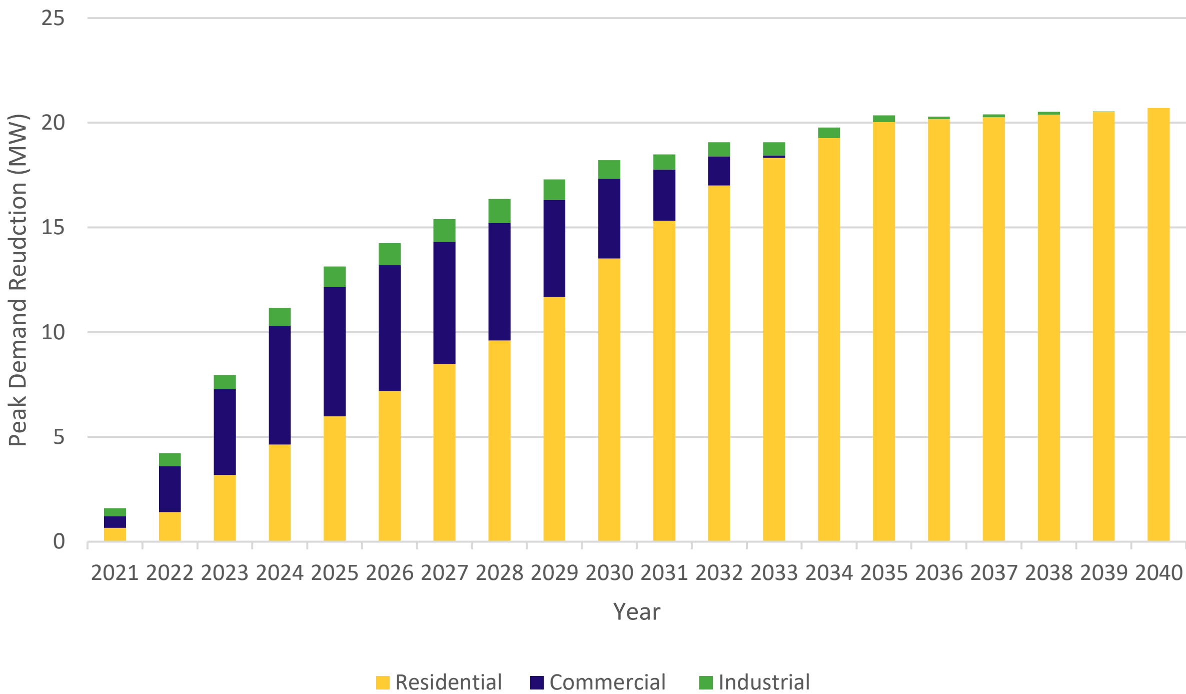

Figure 5-3 | Total Forecast Peak Demand Reduction (Codes, Standards, and CDM Programs)

5.2.3 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, distributed generation in the Northwest region is also forecast to offset some peak demand requirements. The introduction of the Green Energy and Green Economy Act, 2009, and the associated development of Ontario's FIT Program, has increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed distributed generation capacity by fuel type and contribution factor assumptions can be found in Appendix B.10.

After reducing the demand forecast due to conservation as described above, the forecast is further reduced by the expected contribution from contracted distributed generation in the region (similar to the adjustment between net and gross historical demand described in Section 5.1 except with forward looking contracted distributed generation rather than existing distributed generation). Figure 5.5 shows the impact of distributed generation reducing the demand forecast. In the long term, the contribution of distributed generation is expected to diminish as these contracts expire. Note that any facilities without a contract with the IESO are not included in the distributed generation peak demand reduction forecast.

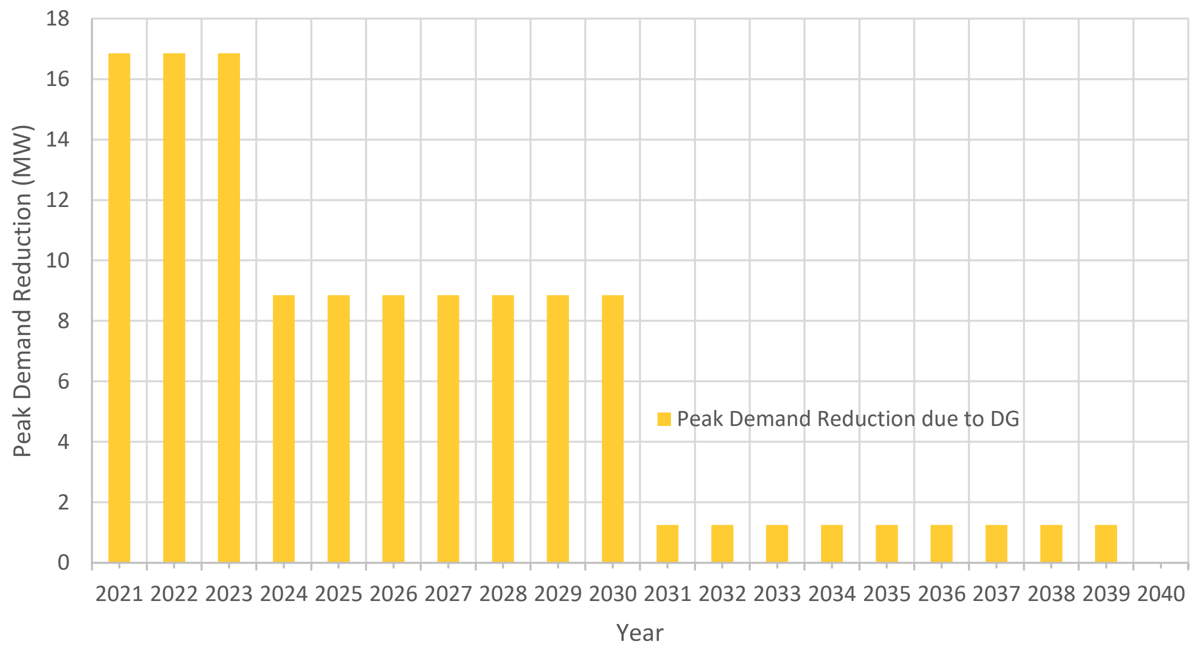

Figure 5-4 | Peak Demand Reduction to Demand Forecast due to Contracted Distributed Generation

5.3 Existing Transmission-connected Forecast

The Northwest region has fifteen customer transformer stations (CTS) that directly serve customers connected to the high-voltage transmission system. The IRRP relies on information from these customers to inform the transmission-connected forecast either directly through their account representative or through comments submitted through the IRRP engagement events. If, for a given station, no information about future demand changes is available, the default assumption is that demand at that station will remain the same as the average historical peak demand over the last five years. Figure 5-5 shows the total non-coincident transmission-connected customer demand forecast. The transmission-connected forecast is generally flat except for a few project expansions/retirements resulting in growth in 2026 and subsequent decline in 2028. Note that, unlike the distribution-connected forecast component, the transmission-connected component is not adjusted for extreme weather because industrial demand does not typically fluctuate with weather. Furthermore, while some customers have behind-the-meter generation facilities, they are not reflected in the forecast unless they are contracted with the IESO.

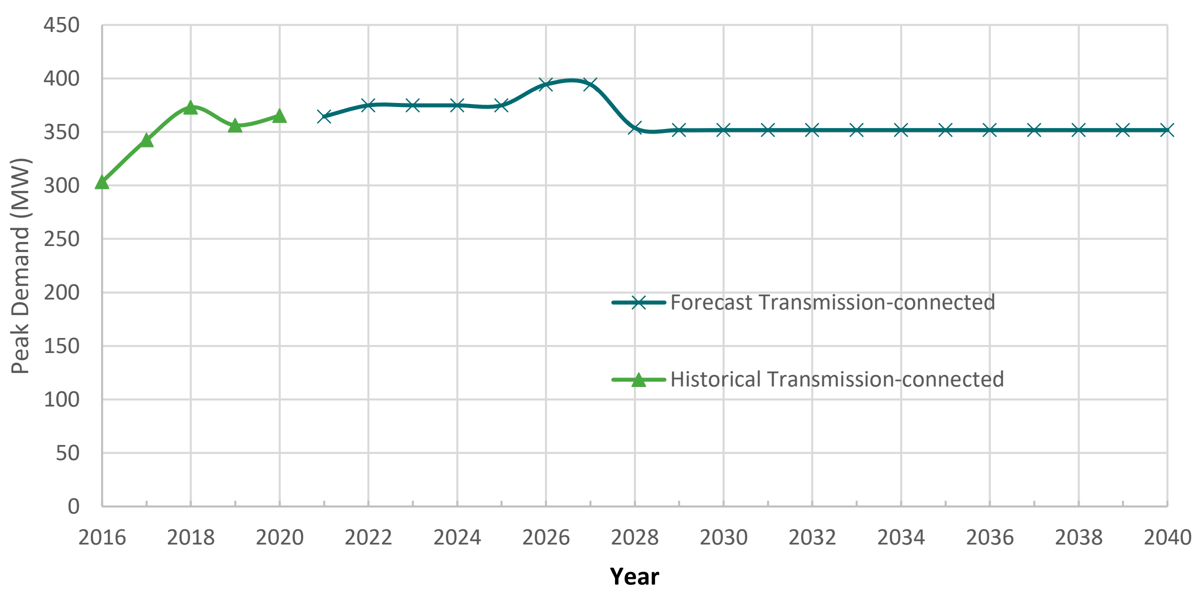

Figure 5-5 | Total Transmission-connected Demand Forecast

5.4 Mining Sector Forecast

In addition to the distribution- and transmission-connected forecasts, expansion of existing mines and new mining projects connecting to the grid are expected to make up the majority of the overall electricity demand growth in the Northwest region. As of Q4 2021, the IESO was aware of more than 20 potential future mining projects in the Northwest region at various stages of planning and development that had known electricity demand forecasts and projected in-service dates. The IESO is also aware of at least ~7-10 projects that are under consideration but have not yet progressed far enough to have an in-service date or electrical demand forecast. Note that information about future mining projects changes frequently. The IESO solicited public feedback on the mining demand forecast and associated list of known mining projects in May 2021. For this IRRP, the mining forecast was considered finalized by the end of 2021 to allow sufficient time for technical assessments that depended on forecast inputs. The mining projects incorporated in the IRRP mining forecast are listed in Appendix B.7.

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.

Table 5-1 | 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 the full undiscounted demand forecast from projects classified as "most likely" and "likely" - Aligned with 2021 Annual Planning Outlook[12] 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

[12] 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.

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 5-1 above.

Figure 5-6 shows the low, reference, and high mining demand forecast scenarios. The total aggregate undiscounted (i.e., without consideration of likelihood factors) forecast demand from all known projects is also shown in a dashed line. Note that the total aggregate undiscounted forecast demand is not a realistic growth scenario since it is highly unlikely for all proposed mining projects to materialized. The undiscounted forecast is provided for transparency to illustrate the scale of potential demand growth considered in the low, reference, and high scenarios.

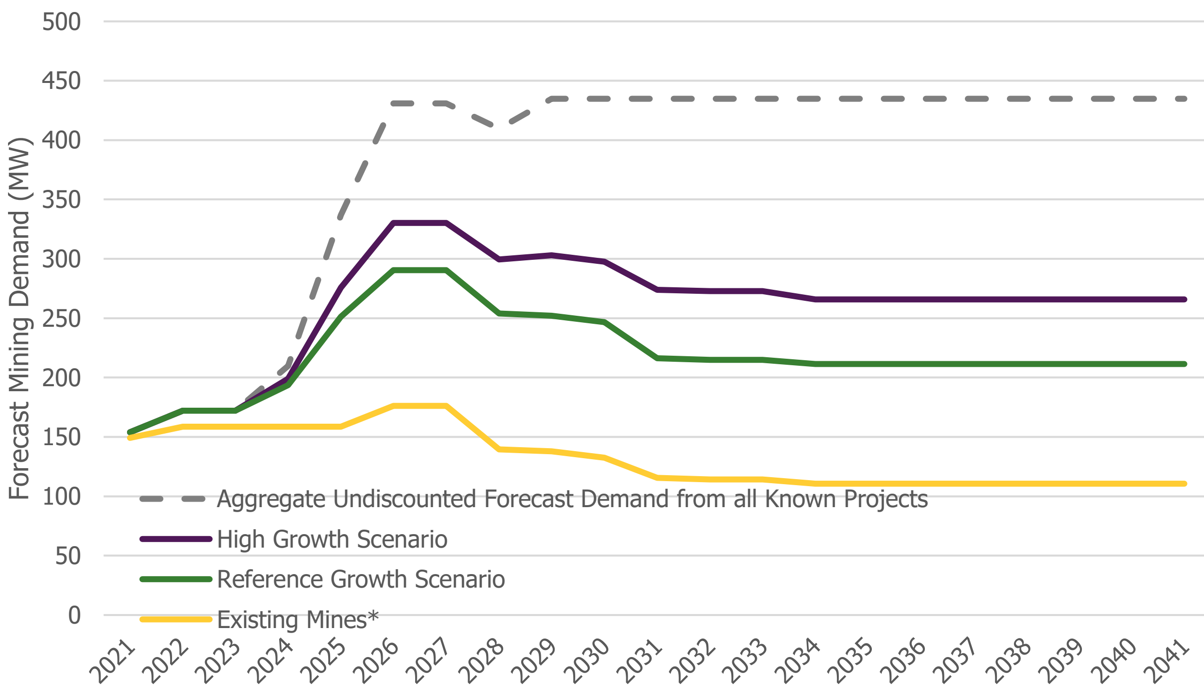

Figure 5-6 | Mining Demand Forecast

The mining sector already accounts for approximately 150 MW of demand today and is projected to grow to 290 MW by 2027 under the reference scenario. The low and high scenarios grow to 175 MW and 330 MW by 2027, respectively. Note that the IRRP does not provide disaggregated project-level forecast to preserve confidentiality.

Generally speaking, the existing mines (low) scenario informs local reliability needs that must be addressed even if no new mines materialize. The reference scenario informs the identification of needs that will likely arise and options to address those needs if/when mines materialize. Finally, the high scenario explores possible additional needs to test the robustness of the IRRP.

Note that in all scenarios, the mining forecast peaks in 2027 before declining for the remainder of the forecast horizon. This is a result of developing a project-based demand forecast as opposed to a top-line forecast for the mining sector as a whole. Information about existing and near-term projects are more readily available than information about long-term projects. Most known near- and mid-term new mining projects plan to come in-service by 2027. After 2027, demand begins to taper off as both existing and new mines reach the end of their planned operating life. The forecast scenarios do account for project extensions beyond their initial operating life but high uncertainty surrounding these extensions has meant that they were assigned low likelihood factors. In sum, the forecast performs well for predicting near- and medium-term mining growth but has less visibility of longer-term trends. Despite this shortcoming, a project-based demand forecast is more useful than a top-line forecast for the purpose of infrastructure planning. The project-based forecast provides relatively detailed information in the near- to mid-term when planning decisions must be made and provides critical geographic granularity necessary for transmission system studies.

5.5 Total Northwest Demand Forecast Scenarios

The total non-coincident Northwest demand forecast is shown in Figure 5-7 below. Note that when the mining forecast component is layered on top of the distribution-connected and transmission-connected components, only the contribution of new mining projects is shown to avoid double counting. The reference scenario Northwest demand grows to 1060 MW by 2027. The low and high scenarios growing to 945 MW and 1100 MW by 2027, respectively. Note that the discontinuity between historical and forecast demand from 2020 to 2021 is partly due to the extreme weather correction applied to the distribution-connected forecast.

The IRRP reference forecast is approximately 20% higher than the Annual Planning Outlook forecast for the Northwest zone. This difference is in part due to the non-coincidence of the IRRP's station-level forecast; the non-coincident forecast is typically 10-15% higher than the coincident forecast in the Northwest. The sum of regional planning forecasts is also generally higher than their bulk planning counterparts since regional forecasts capture potential growth at a greater granularity not all of which may materialize when aggregated at a larger geographic scale.

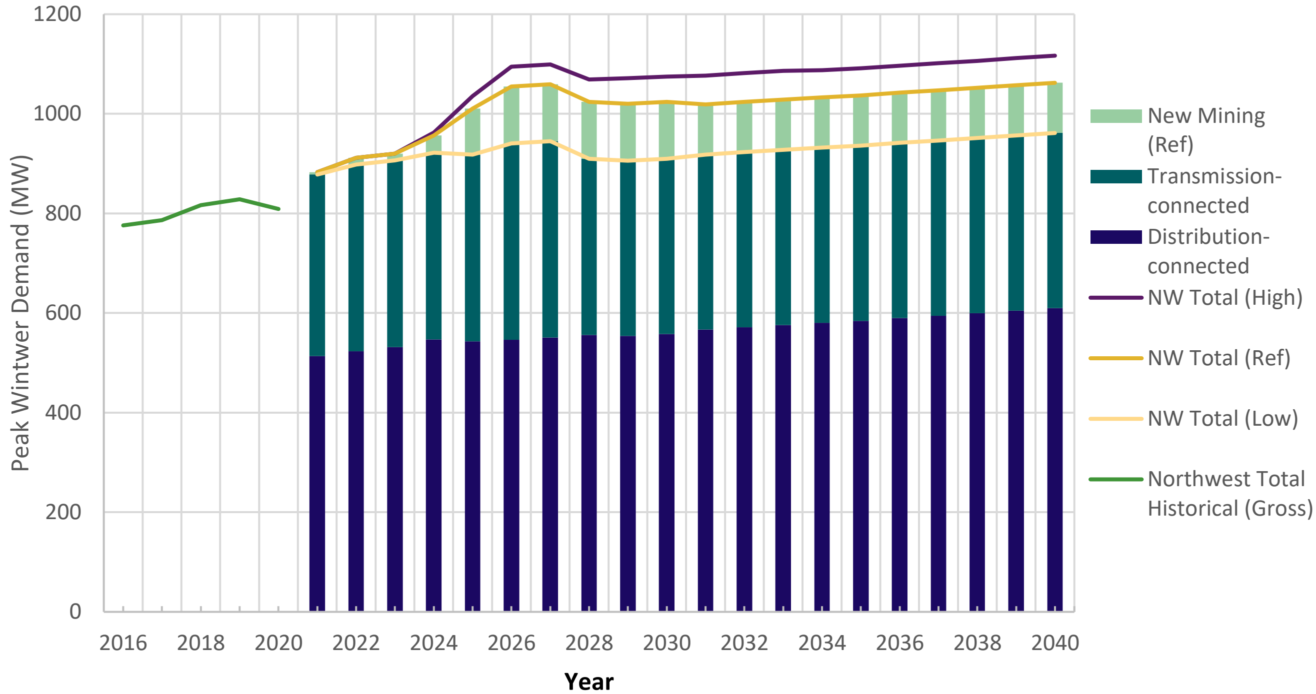

Figure 5-7 | Total Northwest Demand Forecast

5.6 Demand Profiling – Kenora MTS

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) for stations or groups of stations with identified needs can be developed to characterize their needs with finer granularity. This is typically undertaken to inform an analysis of potential non-wires alternatives.

For this IRRP, hourly demand profiles were developed for Kenora MTS where a firm station capacity need was identified for which non-wires alternatives are promising. The Kenora MTS hourly demand profiles can be found in Appendix D.2. There were no other needs identified in this IRRP which could be addressed by non-wires alternatives.

Hourly demand profiles are created by first training a multiple linear regression model with historical data and then repeatedly applying the model under different weather/calendar variable permutations to forecast a range of possible future hourly profiles. The profiles are then ranked based on their median energy values. The median profile is scaled to match the peak demand forecast in each year and used to size and simulate non-wires alternatives as described in Section 7.1. A more fulsome description of the demand profiling methodology can be found in Appendix D.1.

Note that this data is used to roughly inform the overall energy requirements that a non-wire alternative would need to meet for the purposes of evaluating alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Further, this data is only used to select suitable technology types and roughly estimate operating costs. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification achieve greater adoption. The Working Group will continue to monitor these changes as part of the implementation of the plan.

6. Needs

This section summarizes the needs identified through the IRRP process. Taking into account committed transmission projects identified through bulk planning processes (i.e., the East West Tie expansion and the Waasigan transmission line), the Northwest region is generally adequate to support forecast electricity demand growth. The needs identified in the IRRP deal with localized supply to various pockets of demand in the Northwest as well as high-growth scenarios in areas identified as having strong future development potential.

This section is organized as follows:

- Section 6.1 summarizes the methodology for identifying needs,
- Section 6.2 describes firm station capacity and local operational needs (i.e., needs that would materialize under the reference forecast scenario), and
- Section 6.3 describes potential needs that may arise if higher than forecast growth materializes in select subsystems in the region.

Section 6.2.3 (E1C Operation and High Voltage Need), in addition to specifying the needs identified, will also discuss the recommended solutions since there are no "alternatives" that would normally be discussed in Section 7.

Note that bulk system needs are not in scope for the IRRP, which is focused on local reliability and ensuring that local/regional infrastructure can serve forecast demand. Nonetheless, this IRRP report flags any potential interactions between regional and bulk system needs.

6.1 Needs Assessment Methodology

Based on the reference demand forecast (extreme weather, net demand), system capability, transmitters' identified end-of-life asset replacement plans, and the application of ORTAC and NERC/NPCC standards, the Working Group identified electricity needs which generally fall into the following categories:

- **Station Capacity Needs** arise when the demand forecast exceeds the electricity system's ability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service.[13] 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 ability 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 NERC/NPCC standards. LMC studies are conducted using power system simulation analysis. For the high growth sensitivities in Section 6.3, the LMCs for the subsystems in question are higher than the total forecast demand (both reference and high scenarios). Nonetheless, as these areas have been identified to have future development potential, the IRRP explores the existing limitations in these areas to identify the remaining LMC and inform future planning activities should higher growth materialize. Details regarding the power flow simulations, including the system topology and credible contingencies studied, can be found in Appendix C.

- **End-of-life Asset Refurbishment Needs** are identified by the transmitter with consideration to a variety of factors such as asset age, 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 condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. Note that IRRPs do not typically study and make recommendations for all end-of-life needs[14] where like-for-like replacements have been established to be appropriate in earlier phases of the regional planning process. Instead, the IRRP focuses on a subset of end-of-life needs where there are interactions with other regional needs and where there may be opportunities to reconfigure or right-size assets. Therefore, in the sections below, end-of-life needs are described in conjunction with other needs where relevant.

[13] Some stations in the Northwest only have a single transformer in which case the transformer's LTR is the limiting element.
[14] A list of transmission assets reaching end-of-life can be found in the Needs Assessment.

- **Load Security and Restoration Needs** describe the electricity system's ability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

6.2 Needs Identified

Table 6-1 summarizes the firm needs identified in this IRRP and are further discussed in the sections below. Note that the White Dog DS and Marathon DS station capacity needs occur in the long-term and are not further discussed in Section 7 since no firm recommendations are needed at this time.

Table 6-1 | Summary of Needs

Need	Need Description	Need Date
Fort Frances MTS Customer Reliability	Frequent loss of supply due to transmission outages; end-of-life assets at both Fort Frances TS and Fort Frances MTS	Today
E1C Operation	Supply capacity limitations with E1C operated normally closed; high voltage issues with E1C operated normally open	Today
Margach DS	Station step-down transformer capacity	2023
Crilly DS	Station step-down transformer capacity	2027
Kenora MTS	Station step-down transformer capacity	2029
White Dog DS	Station step-down transformer capacity	2032
Marathon DS	Station step-down transformer capacity	2038

6.2.1 Station Capacity Needs

6.2.1.1 Margach DS

Margach DS is approximately 10 km east of Kenora. Margach DS has an LTR of 10.4 MW and historical demand has been stable at just under 10 MW. As shown in Figure 6-1, Margach DS is expected to reach capacity in 2023 due to a large existing industrial customer seeking to be resupplied at Margach DS from a nearby CTS.

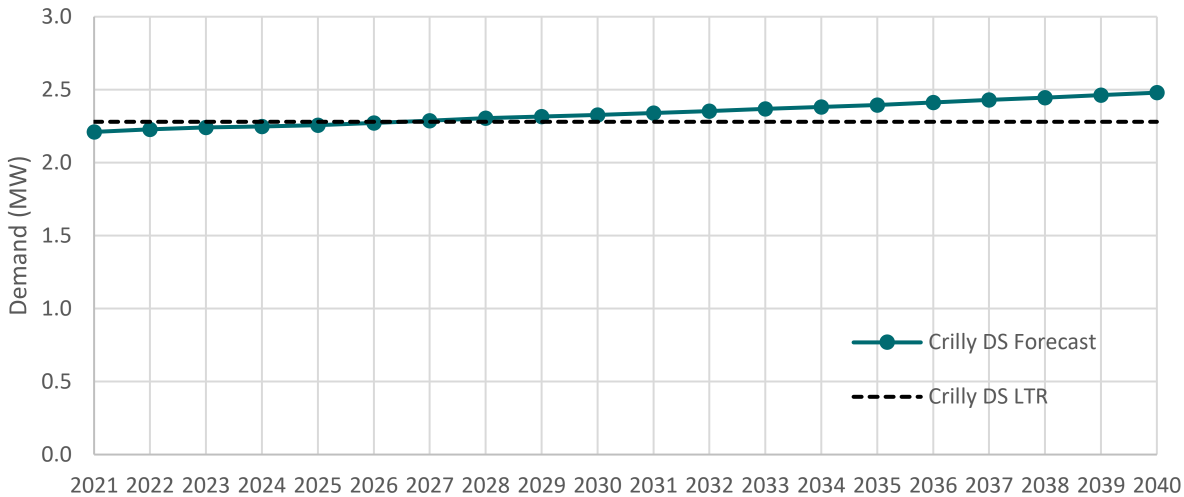

Figure 6-1 | Margach DS Forecast

6.2.1.2 Crilly DS

Crilly DS is a small (~2.2 MW LTR) station supplied from a bus shared with Sturgeon Falls CGS, a small hydroelectric plant approximately 50 km west of Atikokan. This is a non-standard supply arrangement that results in annual outages to Crilly DS when the generator is undergoing maintenance. Diesel generation is currently used for backup power when Sturgeon Falls is on outage. Furthermore, station equipment is nearing end-of-life and space constraints limit in situ refurbishment options.

Crilly DS is expected to reach capacity in 2027 due to incremental growth in the community as shown in Figure 6-2.

6.2.1.3 Kenora MTS

Kenora MTS serves the City of Kenora and has a LTR of 23.4 MW. Synergy North has received inquiries from potential customers seeking new connections, including a new 4 MW project, but no formal agreements have been finalized. While these projects have not been included in the forecast, a relatively high annual growth rate of 1.25% was applied to account for the high degree of development interest.

Figure 6-2 | Crilly DS Forecast

Kenora MTS is expected to reach capacity in 2029 as shown in Figure 6-3.

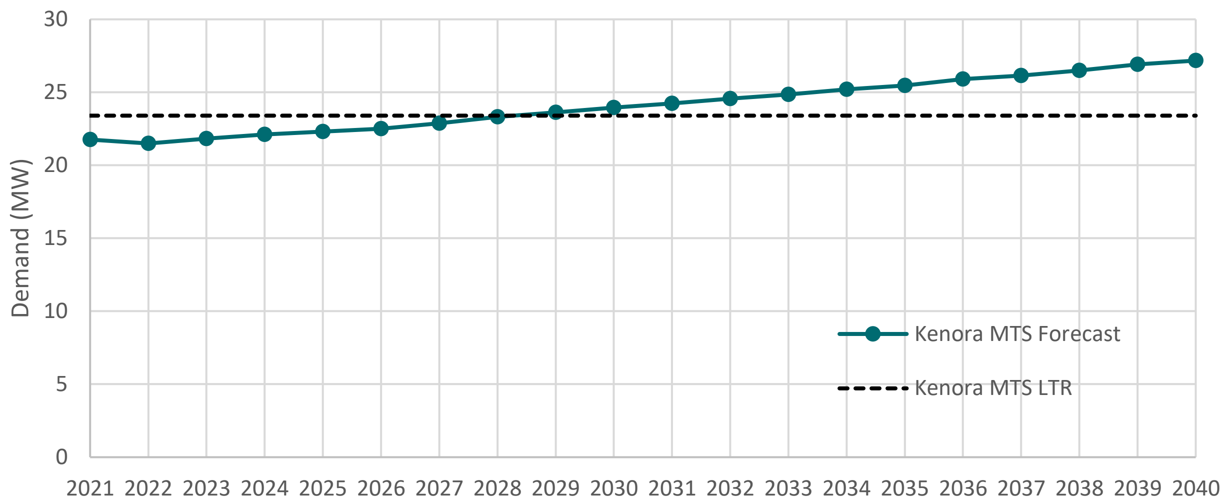

Figure 6-3 | Kenora MTS Forecast

6.2.1.4 White Dog DS

White Dog DS is located approximately 50 km northwest of Kenora and has a LTR of 2.9 MW. White Dog DS demand is expected to grow relatively quickly at an average rate of 1.3% annually due to growth in the community. White Dog DS is expected to reach capacity in 2032 as shown in Figure 6-4.

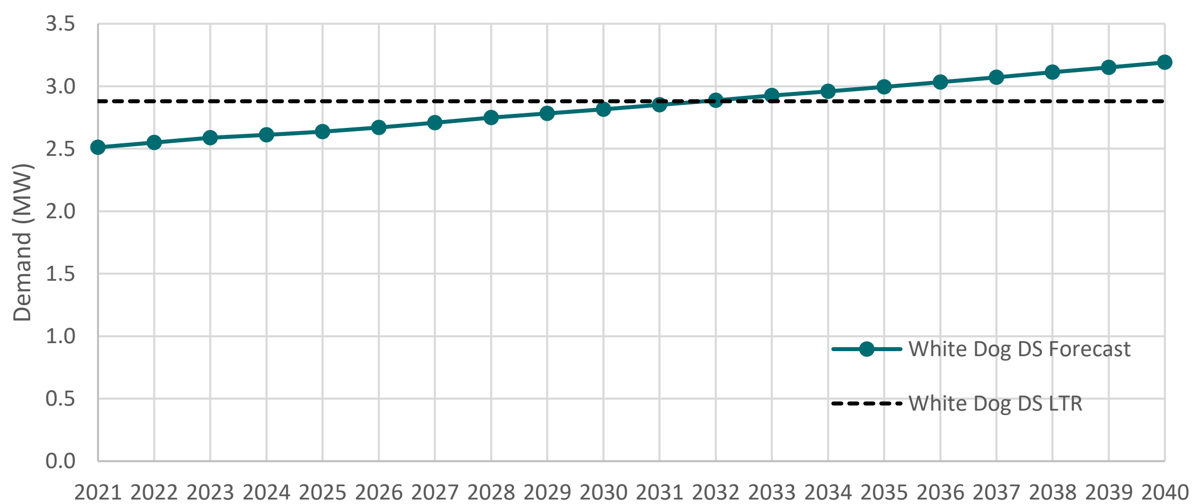

Figure 6-4 | White Dog DS Forecast

6.2.1.5 Marathon DS

Marathon DS serves the Town of Marathon and has a LTR of 10.4 MW. Growth is expected to be moderate and stable at an average annual growth rate of 0.9%. Marathon DS is expected to reach capacity in 2038 as shown in Figure 6-5.

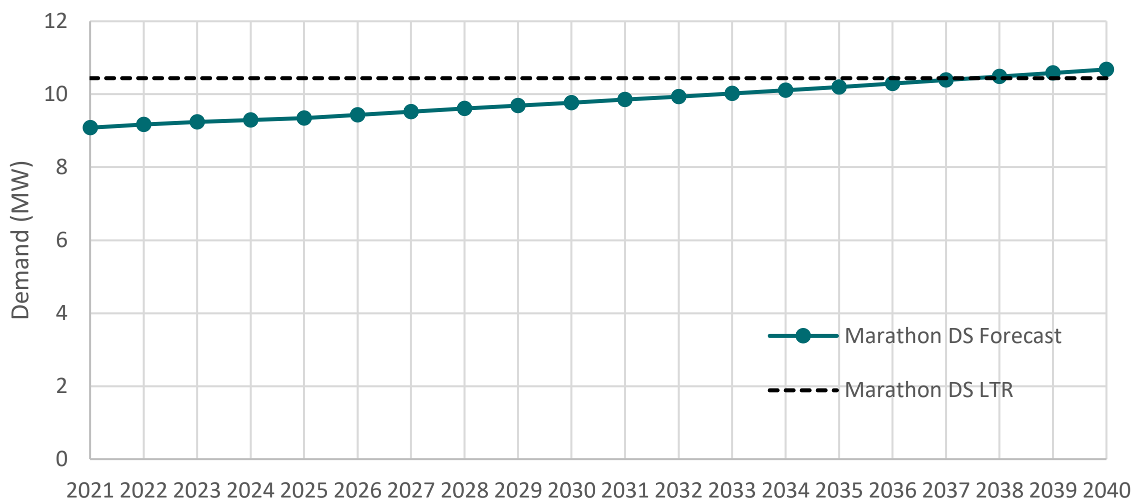

Figure 6-5 | Marathon DS Forecast

6.2.2 Fort Frances Customer Reliability Need

Fort Frances MTS, a step-down transformer station that supplies the Town of Fort Frances, is supplied via a single circuit 115 kV line, F1B, from the nearby Fort Frances TS. The two stations are located across the street from each other as shown in Figure 6-6. Fort Frances MTS experiences outages semi-annually to accommodate planned maintenance outages on F1B. Despite there being two step-down transformers at Fort Frances MTS, the single circuit supply configuration results in community-wide power outages since there is no redundant supply path to the station.

Historically, outage durations ranges from 4 to 8 hours and impact critical loads such as the regional hospital and local health clinics. Customers have raised concerns with interruptions to surgery schedules and vaccine spoilage due to the loss of refrigeration. Power outages also disrupt other commercial and residential customers. Customer surveys conducted by Fort Frances Power suggest that customers can tolerate short outages but are increasing sensitive to prolonged outages. Of the 10 causes of distribution system customer interruptions tracked by the Ontario Energy Board, loss of transmission supply accounts for 90% of Fort Frances Power's customer interruptions over the last 10 years.

Note that this customer reliability issue does not violate ORTAC load security and restoration criteria due to the relatively low total demand served at Fort Frances MTS. Fort Frances MTS serves approximately 16 MW of load today and is expected to grow to 18 MW by the end of the forecast horizon.[15] Load security criteria limits the total amount of demand interrupted with any single element out of service to 150 MW. For loads under 150 MW, load restoration criteria only require that service is restored within 8 hours. Despite compliance with ORTAC criteria, the Fort Frances MTS supply configuration is still highly disruptive for customers and could potentially be improved with relatively low-cost solutions given the proximity to Fort Frances TS.

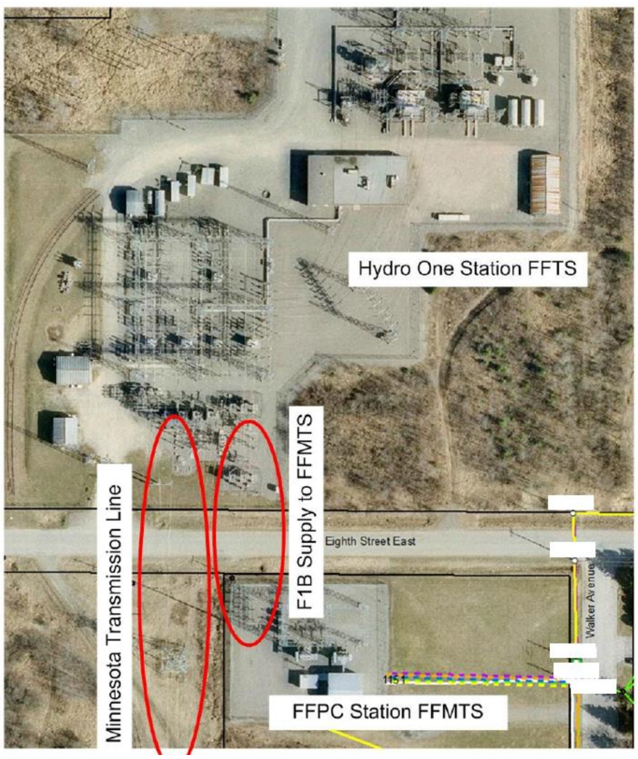

Figure 6-6 | Overhead view of Fort Frances TS (labeled as FFTS) and Fort Frances MTS (labeled as FFMTS)

[15] While there is currently no firm station capacity need within the forecast horizon, several potential large customers have approached Fort Frances Power that could quickly use up the remaining station capacity if they commit. This is further discussed in Section 6.3.2.

Fort Frances MTS station equipment is also aging with both transformers and most breakers dating from the 1960s and 1970s. The OEB's Asset Depreciation Study defines minimum, typical, and maximum useful life for a variety of electricity system assets. Apart from the main station breaker, which was replaced in 2019, all equipment at Fort Frances MTS is between its typical and maximum useful life. Furthermore, Fort Frances TS 115 kV breakers are also approaching end of life around 2027, which presents an opportunity to reconfigure the station to minimize supply interruptions for Fort Frances MTS.

6.2.3 E1C Operations and High Voltage Need

This section discusses the E1C operations with the new 230 kV Wataynikaneyap circuit, W54W, in service. W54W was first energized in Aug 2022. However, C3W, a short 30 m circuit between Wataynikaneyap TS and Pickle Lake SS, is still operated normally open. Therefore, W54W is not yet connected to the existing 115 kV circuits from Ear Falls TS to Pickle Lake SS and Musselwhite CSS (E1C, C2M, and M1M). C3W will be operated closed in the near future so that W54W can help support demand growth on C2M. This is consistent with the IESO's original recommended scope for the Wataynikaneyap Transmission Project in 2016.[16] For the purposes of this IRRP report, W54W being "in-service," refers to the final state with C3W closed. A single-line diagram of the area is shown in Figure 6-7.

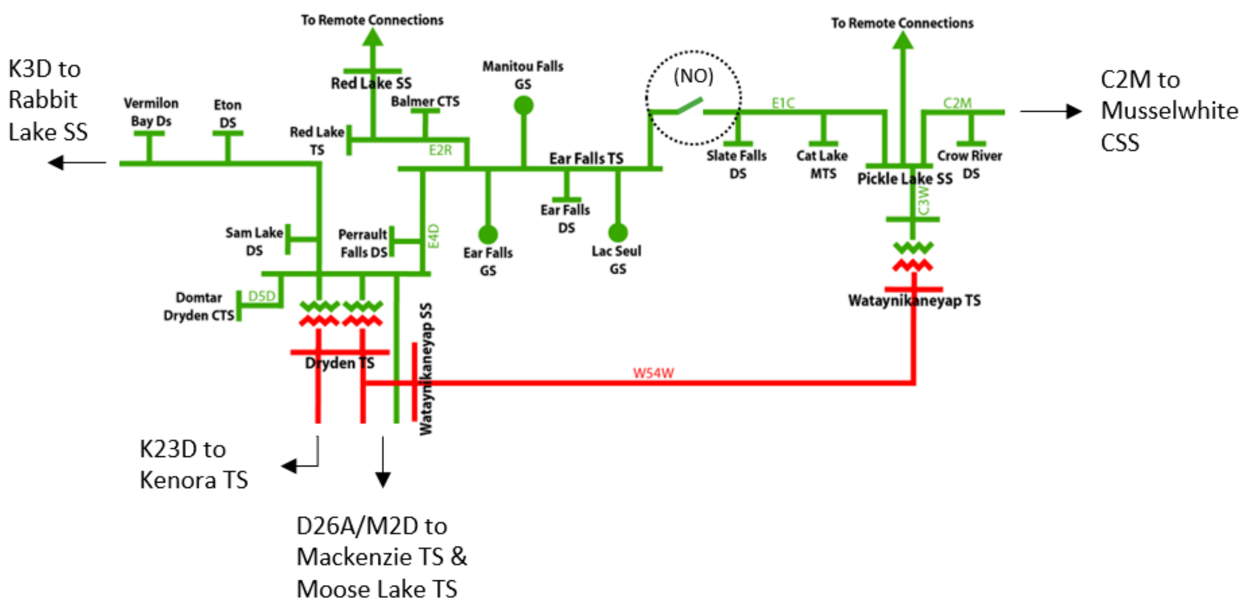

Figure 6-7 | Simplified Single Line Diagram of the Dryden and Pickle Lake Areas with Potential Normally Open Point

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[16] The IESO's 2016 Recommended Scope of the new Line to Pickle Lake and Support Scope for the Remotes Connection Project is available on the Ontario Energy Board's priority transmission projects webpage.

With W54W in-service and connected to E1C via C3W, operating circuit E1C normally closed would result in a loop comprised of the E4D-E1C-W54W circuits. This arrangement would severely limit the transfer capability through E4D and W54W as documented in the 2016 W54W System Impact Assessment (SIA) report.[17] When operating with the E4D-E1C-W54W loop closed, loads in the Ear Falls area will remain connected through E1C via the 230 kV path following the loss of E4D. Post-contingency voltage collapse limits the E4D+W54W flow to 57 MW which is insufficient for supplying existing demand in the Ear Falls, Red Lake, and Pickle Lake areas. The SIA notes that E1C must be opened pre-contingency as a mitigating control action when flow exceeds 57 MW and that this could occur multiple times per day at existing demand levels.

Furthermore, the SIA found that with the E4D-E1C-W54W loop closed, the Manitou Falls and Ear Falls hydro generators would remain connected to the grid following the loss of E4D, which causes transient instability when the post-contingency flow on the E1C exceeds 30 MW. To ensure that transient stability of the generators is maintained, pre-contingency generation levels would need to be reduced such that post-contingency flow on E1C does not exceed 30 MW. This reduction of transfer capability on E1C not only violates ORTAC Section 4.1, which limits reduction in transfer capability that results from a new connection, but would bottle hydro-electric generation that is otherwise available to provide capacity to the Northwest system. Therefore, the SIA recommended that the E4D-E1C-W54W loop should be opened pre-contingency to prevent pre-contingency generation reductions.

Due to these documented issues, this IRRP reaffirms that E1C should be operated normally open once W54W is in-service with C3W closed. This configuration resolves the violations described above and the resulting system is adequate to serve forecast demand in the Ear Falls, Red Lake, and Pickle Lake areas. This configuration is consistent with the recommended scope for W54W (which was referred to as the "Line to Pickle Lake") in the 2015 North of Dryden IRRP. Note that operating E1C normally open enables W54W to relieve E4D which allows W54W to serve the dual purposes of improving the load meeting capability of both the Pickle Lake and Ear Falls/Red Lake areas. This was an important consideration that contributed to the recommendation for W54W.

However, with E1C operated normally open, another problem emerges. High voltage violations (voltages exceeding 127 kV) occur post-contingency under light load conditions. High voltages occur on the line end open of E1C and either Pickle Lake SS or Ear Falls TS depending on where the open point on E1C is located. High voltage violations are less severe when opening E1C near Ear Falls TS compared to near Pickle Lake SS. When E1C is open near Ear Falls TS, the most critical contingency is the loss of one of the existing 20 MVar reactors at Wataynikaneyap TS. The high voltage violations can be addressed by installing an additional 10 MVar reactor at or near Pickle Lake SS. The post-contingency voltages at nearby stations with and without this

[17] The 2016 W54W System Impact Assessment report is available on the IESO's Application Status webpage by searching for SIA ID 2016-567.

additional 10 MVar reactor are shown in Table 6-2. The post-contingency voltages exceed 127 kV at the E1C open line end and Pickle Lake SS for the loss of the existing 20 MVar reactor at Wataynikaneyap TS. Post-contingency voltages are maintained below 127 kV with the additional 10 MVar reactor.

Table 6-2 | Post-contingency Voltages with and without Additional 10 MVar Reactor at Pickle Lake SS with E1C Normally Open at Ear Falls TS

Bus/ Station Name	Post-contingency voltage (kV)	Post-contingency voltage (kV) with additional 10 MVar Reactor at Pickle Lake SS
E1C LEO	**130.7**	123.3
Pickle Lake 115	**127.7**	120.6
Watay 115	126	120.1
Watay SS 230	238	235.5
Dinorwic 230	237.8	235.6
Mackenzie 230	244.8	244
Musselwhite 115	120	115.1

The IRRP recommends that the IESO and Hydro One collaborate in the Regional Infrastructure Plan refine the location of the E1C open point and associated reactive compensation devices required. The E1C open point can be fine-tuned to minimize high voltages. The open point on E1C should consider the location and condition of existing switches as well as their accessibility for restoration purposes should E1C be needed to partially restore loads following a W54W or D26A contingency.

Furthermore, the Regional Infrastructure Plan should consider the installation of a voltage-based automatic switching scheme for the reactors at Pickle Lake SS, Wataynikaneyap TS, and Dinorwic Jct similar to existing switching schemes at other stations across the Northwest region. Voltage-based automatic switching would improve the transmission system's operational flexibility, help manage high voltage conditions currently experienced across the Northwest and help reduce post-contingency high voltages to the acceptable continuous maximum voltage within 30 minutes. Potential interactions with the existing Northwest reactor switching scheme should be considered as this scheme is developed.

6.3 Potential Needs and High Sensitivities

No firm regional supply capacity needs were identified in the Northwest in either the reference or high forecast scenarios. However, most of the growth in the Northwest is driven by large mining and industrial development which can add large, incremental blocks of demand with minimal lead time that can quickly use up remaining supply capacity. Through engagement with development proponents and stakeholders, the Working Group identified two areas in the Northwest, the Dryden/Ear Falls/Red Lake area and the Fort Frances area, where there is particularly strong development interest and where the existing transmission system, although adequate for current forecast scenarios, may become constrained if all known proposed projects materialize.

For these two areas, the IRRP studied high growth sensitivities to quantify the load meeting capability and identify the limiting phenomena on the existing system. This was accomplished by adding hypothetical loads at existing stations/busses to simulate new developments and increasing the hypothetical load until a planning standards violation was observed.

As discussed in Section 4.1, the IRRP did not study local connection requirements of any individual project. The purpose of the high growth sensitivity studies is to quantify system limitations so that growth can be more effectively monitored between regional planning cycles and future planning activities can be initiated in a timely manner if growth materializes. Regardless of the availability of regional supply capacity identified in the IRRP, customers seeking connection may be subject to additional requirements and limitations specified in Customer Impact Assessments (CIA) or System Impact Assessments (SIA).

6.3.1 Dryden/Ear Falls/Red Lake Load Meeting Capability

The Dryden/Ear Falls/Red Lake area hosts significant mining activity today. It includes the 115 kV system supplied from the Dryden TS autotransformers, circuit K3D from Rabbit Lake SS, and M2D from Moose Lake TS. The recently completed 230 kV Wataynikaneyap Transmission Project line W54W will help relieve constraints on the 115 kV circuit E4D, once the recommendations in section 6.2.3 are implemented, and no incremental capacity needs are anticipated in this area based on the current demand forecast.[18]

The area's load meeting capability (LMC) is a function of three nested local constraints as shown in Figure 6-8:

(1) Supply to the Red Lake subsystem including: Red Lake TS, Balmer CTS, and Red Lake remote communities

[18] Consistent with the recommendation in Section 2.1.5 (E1C Operation and High Voltage) and the needs discussed in Section 6.2.3, the IRRP technical studies assumes that E1C will be operated normally open at Ear Falls TS.

(2) Supply to the Ear Falls subsystem including: Ear Falls DS, Perrault Falls DS, and the Red Lake subsystem described above

(3) Supply to the Dryden subsystem including: Sam Lake DS, Eton Ds, Vermilion Bay DS, Domtar Dryden CTS, and the Ear Falls subsystem described above

An implication of this "nesting" is that, depending on where new loads connect, they could contribute to one or more subsystem needs. For example, a load connecting close to Dryden would contribute to needs in the Dryden subsystem only, whereas a load connecting at Red Lake would contribute to potential needs in all three subsystems.

The supply capacity in these subsystems may be further constrained by bulk system limitations on the 230 kV supply to the area West of Thunder Bay. Bulk system limitations are outside the scope of regional planning and will be addressed by the Waasigan Transmission Line Project.

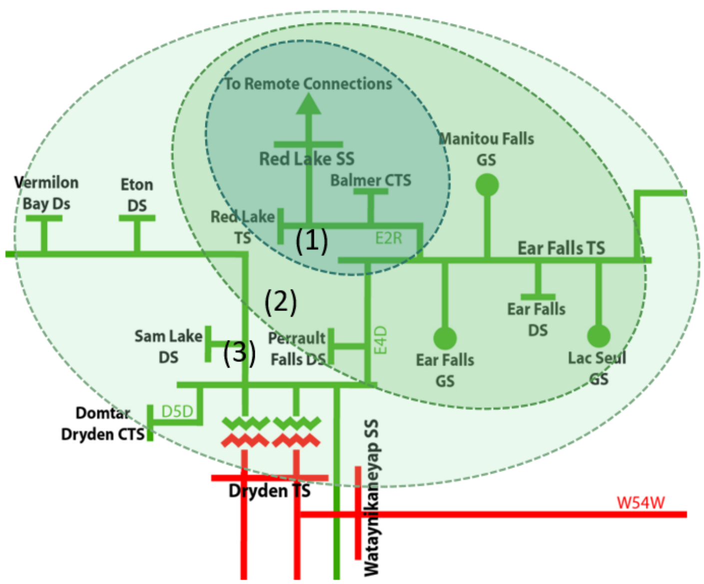

Figure 6-8 | Dryden/Ear Falls/Red Lake Nested Subsystems

Depending on which subsystem was being tested, the load meeting capabilities were derived by adding new hypothetical loads at Red Lake TS, Ear Falls TS, or the 115 kV bus at Dryden TS until a limiting phenomenon was encountered. The load meeting capabilities and the most limiting phenomenon or season for each subsystem is summarized in Table 6-3 and further described below. Note that, since the Northwest region is winter peaking, the IRRP forecast was developed for winter peak demand. However, since the Ear Falls and Red Lake subsystems can be thermally constrained, a summer peak forecast was also developed using the historical ratio between each station's summer and winter peaks.

Table 6-3 | Summary of Dryden/Ear Falls/Red Lake Load Meeting Capabilities

Subsystem	Load Meeting Capability	2032 Reference Peak Demand Forecast	2040 Reference Peak Demand Forecast
1. Red Lake	74 MW (summer thermal limitation)	61 MW summer peak	67 MW summer peak
2. Ear Falls	90 MW (summer thermal limitation)	67 MW summer peak	74 MW summer peak
3. Dryden	160 MW [19](summer/winter voltage decline)	129 MW winter peak	140 MW winter peak

6.3.1.1 Red Lake Subsystem

The Red Lake subsystem load meeting capability is limited in the summer by pre-contingency thermal overload of circuit E2R. The E2R continuous summer rating is 421 A which translates to a load meeting capability of approximately 74 MW.

The winter load meeting capability is higher than the summer capability. The winter load meeting capability is limited to 93 MW due to E2R pre-contingency thermal and voltage limitations. The winter E2R continuous winter rating is 528 A which translates to a load meeting capability of approximately 93 MW. 93 MW of load also causes pre-contingency voltage decline at Red Lake TS (i.e., voltages are under 113 kV). Note that the pre-contingency voltage limitation can be mitigated by installing appropriately sized voltage devices at the connection point of any new load. All load meeting capabilities described for the Red Lake and Dryden subsystems below assume that any new load will be accompanied by voltage devices to maintain adequate voltage performance at the point of connection.

Figure 6-9 below shows the Red Lake subsystem summer and winter peak demand forecast and associated load meeting capabilities.

The summer thermal limitation on E2R could be addressed by upgrading to higher rated conductors. There are several conductor options available with summer continuous ratings ranging from 590 A to 740 A.

[19] This LMC is significant higher than the existing Dryden Area Inflow (DAI) limit in existing System Control Orders documentation. This difference is mainly due to topology changes (i.e. new W54W). The IRRP sensitivity study also assumes that new loads will connect with appropriate voltage control devices installed at the point of connection which alleviates previously documented low voltage issues.

Upgrading to 740 A conductors would result in a summer load meeting capability of approximately 130 MW. Note that upgrading to higher rated conductors would also necessitate replacing existing structures to increase their height so that the conductors can be operated at a higher temperature. Furthermore, Red Lake TS would need an alternative supply while work on E2R is carried out. Upgrading E2R would cost approximately $23M (real $2022 overnight capital cost) based on high-level per km refurbishment costs for typical 115 kV wood pole lines.[20] The cost difference between different conductor choices is relatively insignificant. Note this is a planning-level estimate (-50% to +100%); material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs.

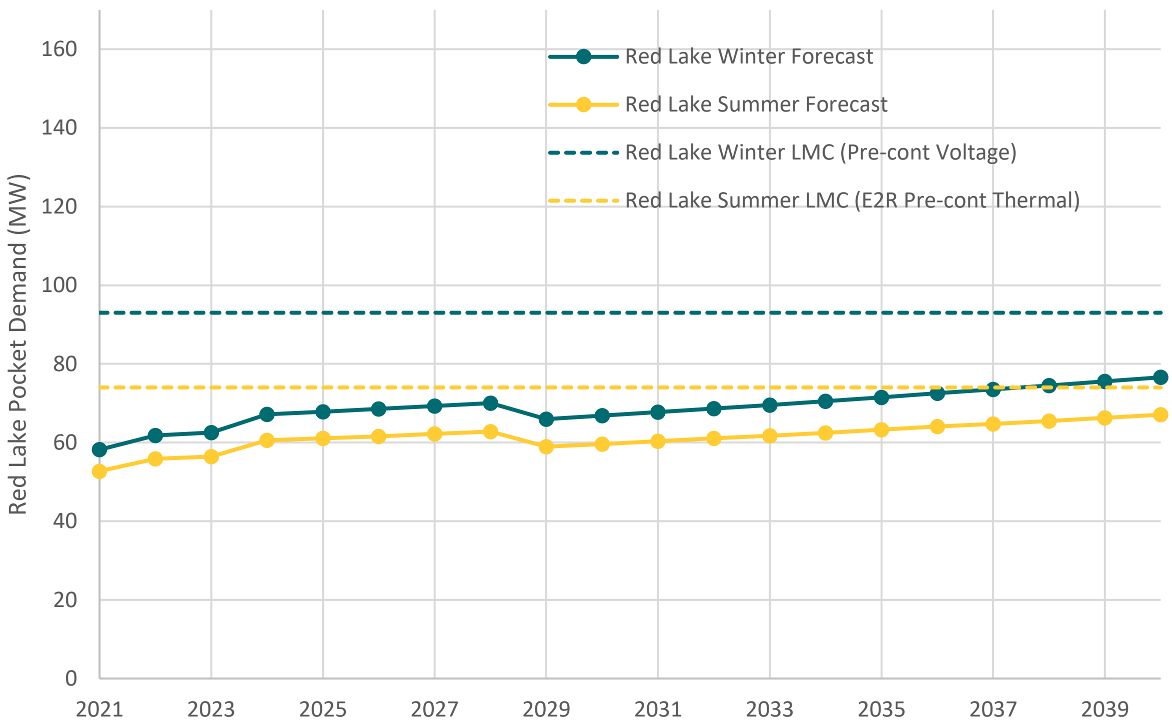

Figure 6-9 | Red Lake Subsystem Load Meeting Capabilities and Demand Forecast

E2R is approximately 75 years old. Hydro One anticipates that the average expected service life for the conductors is 90 years. The wood pole structures have a shorter expected service life at approximately 50 years. The end-of-life date for E2R will be based on actual asset conditions and no date has been determined for E2R as of 2022. If growth materializes, future planning

[20] The provided cost estimates do not include any associated upgrades that may be required to achieve the desired rating (e.g., raising poles, etc.) and should be viewed as high-level minimum costs.

studies should consider the cost of advancing E2R refurbishment as compared to alternatives such as local generation.

6.3.1.2 Ear Falls Subsystem

The Ear Falls subsystem load meeting capability is limited in the summer by E4D pre-contingency thermal overload. The E4D continuous summer rating is 410 A, which translates to approximately 72 MW. There is also a combined 18 MW of summer 98th percentile dependable hydro generation output from Ear Falls GS, Manitou Falls GS, and Lac Seul GS. Together the thermal capability and hydro generation results in a load meeting capability of approximately 90 MW.

Note that the winter load meeting capability is not expected to be limiting since it is significantly higher than the summer capability due to both the higher winter thermal rating of the circuit as well as higher dependable hydro generation output (approximately 64 MW of 98th percentile dependable hydro generation output).

Figure 6-10 below shows the Ear Falls subsystem summer demand forecast and load meeting capability.

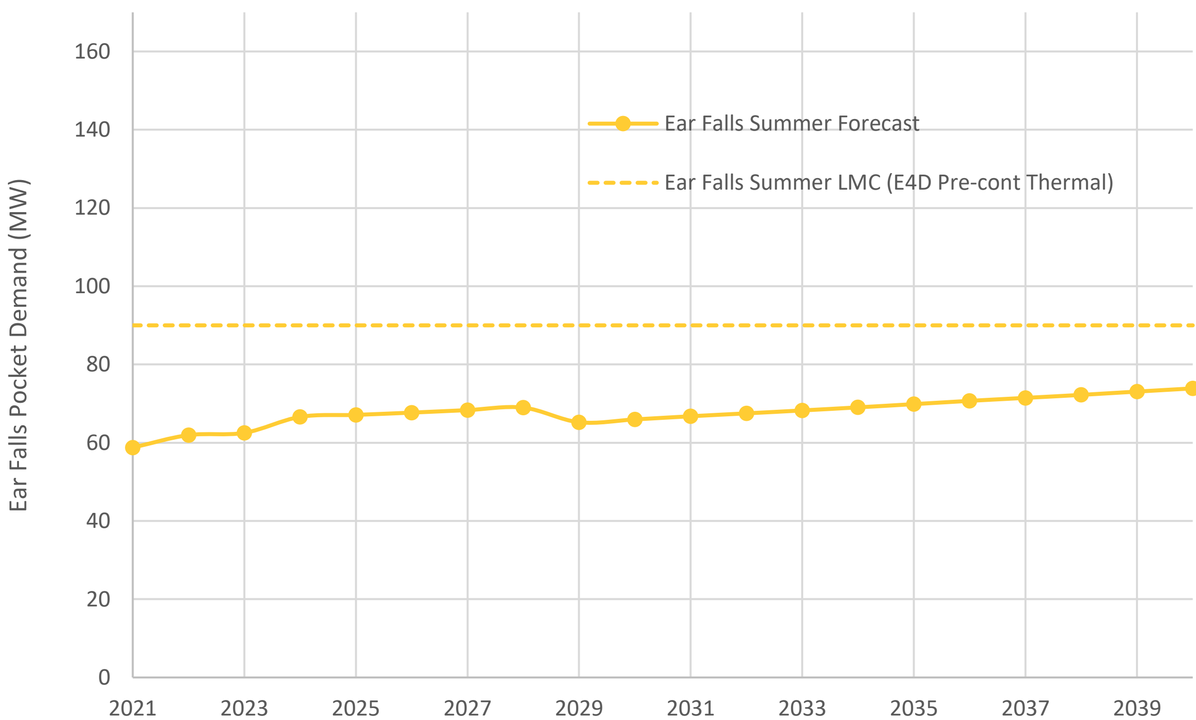

Figure 6-10 | Ear Falls Subsystem Load Meeting Capability and Demand Forecast

The summer load meeting capability for the Ear Falls subsystem can be increased to 130 MW by upgrading E4D with higher rated conductors (740 A summer continuous rating similar to conductors contemplated for E2R in the previous section). Upgrading E4D would cost approximately $35M (real $2022 overnight capital cost) based on high-level per km refurbishment costs for typical 115 kV wood pole lines.[21] Note this is a planning-level estimate (-50% to +100%); material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs. E4D is approximately the same age as E2R; future planning studies should also consider the cost of advancing E4D refurbishment as compared to alternatives such as local generation.

6.3.1.3 Dryden Subsystem

The Dryden subsystem load meeting capability is limited to 160 MW in both the summer and winter due to post-contingency voltage decline following the loss of D26A. When total demand in the Dryden subsystem exceeds 160 MW, the voltage decline at Dryden TS will exceed criteria (10% decline) as shown in Table 6-4. Note that for the purpose of deriving a conservative load meeting capability, a constant MVA load model was used as opposed to a voltage dependent load model.

Table 6-4 | Post-Contingency (D26A N-1) Voltage Change (160 MW Dryden Subsystem Total Demand)

Station	Pre-Cont Voltage	Post-Cont (Pre-ULTC) Voltage	Post-Cont (Post-ULTC) Voltage
Mackenzie TS	247 kV	242 kV	239 kV
Dryden TS	237 kV	216 kV	214 kV (10% decline)
Kenora TS	243 kV	229 kV	230 kV
Fort Frances TS	244 kV	229 kV	231 kV

Dryden TS post-contingency voltage decline will no longer be limiting once Phase 2 of the Waasigan Transmission Line Project is built since it will provide a redundant path from Mackenzie TS to Dryden TS parallel to D26A. Without Phase 2, the post-contingency voltage decline could be addressed by a dynamic voltage device at Dryden TS, but this was not further studied since the device requirements would depend on the connection arrangement and characteristics of future loads.

[21] The provided cost estimates do not include any associated upgrades that may be required to achieve the desired rating (e.g., raising poles, etc.) and should be viewed as high-level minimum costs.

Note that the D26A + K23D N-1-1 contingency results in more severe voltage decline but could be addressed by a load rejection scheme since special protection systems are permitted by ORTAC for outage conditions.

Figure 6-11 shows the Dryden subsystem summer and winter peak demand forecast and associated load meeting capabilities.

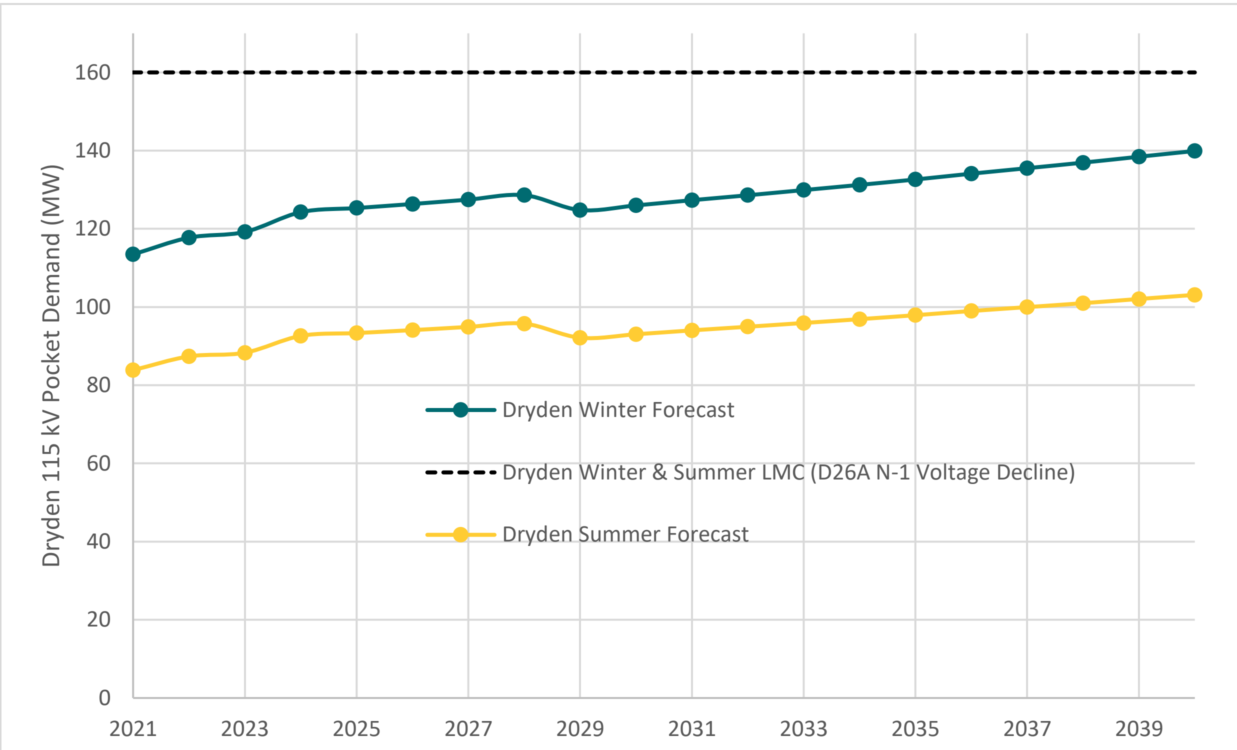

Figure 6-11 | Dryden Subsystem Load Meeting Capabilities and Demand Forecast

6.3.2 Fort Frances Load Meeting Capability

The Fort Frances area includes the 115 kV system supplied from the Fort Frances TS autotransformers and circuit K6F from Rabbit Lake SS as shown in Figure 6-13. For this high-growth sensitivity study, the Fort Frances area includes Fort Frances MTS, Burleigh DS, and a new hypothetical load connected directly to the 115 kV bus at Fort Frances TS. The stations connected to K6F do not materially impact the load meeting capability of the Fort Frances area.

Forecast demand in the Fort Frances area is relatively modest and is expected to grow from 21 MW today to 23 MW in 2040. However, the Working Group is aware of multiple inquiries from potential large new customers seeking connection in the Fort Frances area. Their combined load exceeds 100 MW but there is a high degree of uncertainty in whether their developments will proceed and where they may choose to connect to the grid. Some potential customers are also considering connection points in other parts of the province.

The Fort Frances load meeting capability is limited to 82 MW inclusive of approximately 3 MW of 98th percentile winter dependable hydro generation output from Fort Frances GS. This load meeting capability is the maximum total amount of load that can be served at Fort Frances MTS, Burleigh DS, and a new hypothetical load directly served on the Fort Frances TS 115 kV bus. It does not include load served on K6F. To achieve this load meeting capability, two new 25 MVar capacitor banks are assumed to be installed on the Fort Frances TS 115 kV bus to manage pre-contingency voltages. The load meeting capability is limited by post-contingency voltage decline on the Fort Frances TS 115 kV bus following the loss of F25A as shown in Table 6-5. The F25A contingency has a significant impact on 115 kV bus voltages because it removes one of the Fort Frances TS transformers (and the existing capacitor bank on its tertiary winding) by configuration. Note that for the purpose of deriving a conservative load meeting capability, a constant MVA load model was used as opposed to a voltage dependent load model.

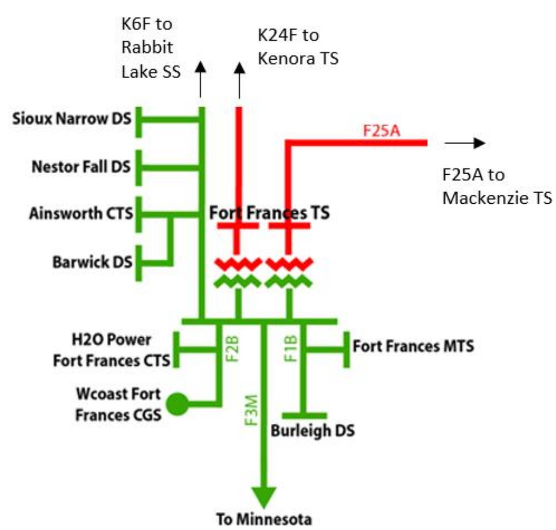

Figure 6-12 | Fort Frances Subsystem

Figure 6-13 below shows the Fort Frances subsystem winter peak demand forecast and associated load meeting capability.

Table 6-5 | Post-Contingency (F25A N-1) Voltage Change (82 MW Fort Frances Subsystem Total Demand)

Station/Bus	Pre-Cont Voltage	Post-Cont Pre-ULTC Voltage	Post-Cont Post-ULTC Voltage
Fort Frances TS (230 kV)	240 kV	234 kV	228 kV
Fort Frances TS (115 kV)	123 kV	110 kV (10% decline)	116 kV

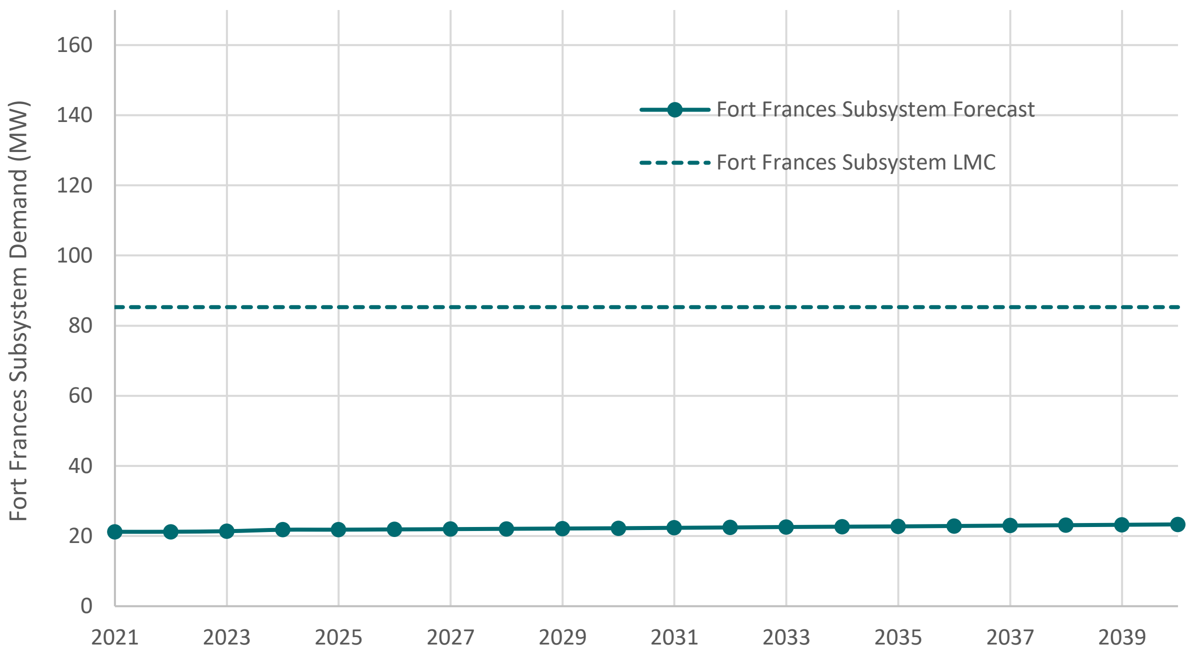

Figure 6-13 | Fort Frances Subsystem Load Meeting Capability and Demand Forecast

7. Options Considered and Recommendations

This section describes the options considered and recommendations to address the near- to medium-term needs identified in section 6. This section is organized as follows:

Section 7.1 describes the options considered for the Margach DS, Crilly DS, and Kenora MTS station capacity needs. This includes a discussion of how each station capacity need was screened for non-wires alternative suitability and, where there were promising non-wires opportunities, the options considered and financial analysis.

Section 7.2 explores configuration options to improve customer reliability at Fort Frances TS. These options will inform the Regional Infrastructure Plan where a final configuration will be chosen.

Note that the recommendation for the E1C operations and high voltage need can be found in Section 6.2.3 and will not be further discussed in this section.

7.1 Options and Recommendations for Station Capacity Needs

7.1.1 Methodology and Options Considered

There are two approaches for addressing station capacity needs:

- Build new infrastructure to increase station capacity. This is commonly referred to as a "wires" option and typically entails upsizing the existing station (e.g., replacing transformers with higher rated transformers or adding additional transformers) or building a new station to supply incremental demand growth. Wires options may also include modifications to or the addition of other power system equipment such as voltage regulation devices, switches, or breakers.

- Install or implement measures to reduce net peak demand to maintain loading within existing station capacity. This is commonly referred to as a "non-wires" alternative and can include options like energy storage, local distributed generation, demand response, conservation and demand management, or any combination of the above. Note that centrally delivered energy efficiency measures under the 2021-2024 Conservation and Demand Management framework are already included in the load forecast, as discussed in Section 5.2.2. Additional conservation and demand management can be considered as a non-wires alternative.

While wires options typically provide a step-change increase in capacity and are available in all hours, non-wires alternatives are more targeted and must account for the frequency and duration of the capacity need in addition to its magnitude. Therefore, identifying suitable technology types, sizing options, and simulating their discounted cash flows are significantly more complex for non-wires alternatives than wires options.

Non-wires alternatives are not suitable for all station capacity needs and there are often qualitative factors that rule out the use of non-wires alternatives. Before carrying out options analysis, a screening process is first applied to determine the suitability of non-wires alternatives for each need that considers the characteristics of the demand growth, the technical feasibility of non-wires alternatives to address the limiting phenomena, and any additional factors that would complicate or facilitate the implementation of non-wires alternatives. For stations where non-wires alternatives are suitable, the IRRP carries out options analysis as described below.

High-level cost estimates for wires options are usually provided by the transmitter. In contrast, cost estimates for generation and other non-wires alternatives are based on benchmark capital and operating cost characteristics for each resource type and size. Note that the error margin in cost estimates is significant at the planning stage (-50% to +100%); they are only intended to enable comparison between options during the IRRP. Material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs. Wires option costs can be reviewed in the Regional Infrastructure Plan before implementation work begins and the Working Group will revisit recommendations if cost estimates differ significantly. Actual non-wires alternative costs can also vary significantly from the benchmark estimates used in the IRRP depending on local market constraints at the time of implementation. The entity responsible for implementing the non-wires alternative (for station capacity needs, this will typically be the local distribution company) will only implement the alternative if it remains cost effective. Subsequent regional planning activities will be triggered if future costs differ significantly from those in the current IRRP.

For non-wires options, upfront capital and operating costs are compiled to calculate the levelized unit energy cost ($/MW-year). Similarly, an annual revenue requirement ($/year) is compiled for wires options. For each option, a discounted cash flow model is created which includes the levelized unit energy cost or annual revenue requirement as well as bulk system energy and capacity costs where applicable. Note that, in order to enable an apples-to-apples comparison, the discounted cash flow for the non-wires options includes a credit for the bulk system capacity value it provides. The discounted cash flow model for all options is compiled over the lifespan of the longest option considered (typically 70 years for wires options). The net present value (in 2021 CAD dollars) of these cash flows are the primary basis through which options are compared.

A list of the assumptions made in the economic analysis can be found in Appendix E.

7.1.2 Options and Recommendation for Crilly DS

Crilly DS is expected to reach capacity in 2027. Crilly DS is a small (LTR of ~2.2 MW) station supplied from a bus shared with Sturgeon Falls CGS, a small hydroelectric plant approximately 50 km west of Atikokan. This is a non-standard supply arrangement that results in annual outages to Crilly DS when the generator is undergoing maintenance. Diesel generation is currently used for backup power whenever Sturgeon Falls is on outage. Furthermore, the existing station equipment will reach end-of-life over the next ~10 years and space constraints limit in situ refurbishment options.

Non-wires alternatives are not suitable for Crilly DS due to three factors. First, non-wires alternatives will not be able to eliminate nor reduce existing reliance on backup generation. Load modifying non-wires alternatives (e.g., energy efficiency measures or demand response) could potentially reduce peak demand and overall energy consumption but, when transmission supply is interrupted due to Sturgeon Falls outages, they cannot replace the need for backup generation. Similarly, distributed energy resources can reduce peak demand below the station LTR but, during outages, the distribution system served by Crilly DS must still rely on backup diesel generation. Frequent reliance on backup diesel generation results in poor reliability and is technically challenging due to difficulties in staying connected and maintaining power quality when supplying loads on a long single-phase distribution line. The long-term solution for Crilly DS station capacity should ideally provide reliability on par with other single circuit supply stations (where regular supply interruptions are not required for generator maintenance outages).

Second, structures and equipment at Crilly DS are approaching end-of-life in the near future. While the specific end-of-life dates vary based on asset conditions, existing structures and equipment are expected to require refurbishment/replacement over the next 10 years. Even if non-wires alternatives can address overloads due to incremental growth above the current station capacity, the station must still be rebuilt/refurbished at end-of-life.

Third, Crilly DS serves a small pool of customers (approximately 500 homes and businesses) in a remote location. This customer pool is too small to cost-effectively target energy efficiency or demand response measures since the overhead costs will likely be prohibitive compared to the potential savings in deferred or upsized infrastructure. Furthermore, while voluntary energy efficiency and demand response programs can produce predictable results when applied over large populations, the demand savings when targeted to a small group of customers is unreliable.

Since non-wires alternatives are not suitable for Crilly DS, Hydro One Distribution is considering the follow wires options:

- Refurbish Crilly DS at its current location (and continue to rely on backup power during outages),

- Rebuild Crilly DS at a different location as a 115/25 kV HVDS (close to the existing station/supply point),
- Rebuild Crilly DS at a different location as a 230/25 kV HVDS (connected to F25A closer to the community served by Crilly DS), or
- Replace Crilly DS with 115:25 kV padmount transformer (transformer enclosed in a grounded cabinet that can be accommodated outside the existing station fence).

The cost of these wires options ranges from $7.5-15M (including line work required for connection) and will address both the station capacity and end-of-life needs. Refurbishing Crilly DS at its current location is likely the least costly option but is undesirable due to the continued reliance on backup power. Furthermore, the incremental capacity that can be accommodated at the existing location may be limited due to the space constraints. Rebuilding Crilly DS as a full HVDS (either at 115 kV or 230 kV) would offer the best reliability and performance but also at the greatest cost. Replacing Crilly DS with a padmount transformer may be a more cost-effective option but there are still technical hurdles to be further investigated such as the ability for 115 kV protections to be accommodated within a padmount configuration.

Since non-wires alternatives are not suitable and there are no upstream supply capacity needs that require further regional coordination, the IRRP recommends that Hydro One Distribution conduct local planning, in coordination with the Regional Infrastructure Plan, to refine refurbishment/new station options identified in the IRRP with the goal of balancing reliability improvements and cost.

7.1.3 Options and Recommendation for Margach DS

Margach DS is expected to reach capacity in 2023 due to a large existing industrial customer seeking to be resupplied from a nearby CTS. Margach DS is approximately 10 km east of Kenora.

Non-wires alternatives are not suitable for addressing the Margach DS station capacity need due to the timing and magnitude of the demand increase. Resupplying the large industrial customer causes the forecast demand at Margach DS to jump by 40% from 2022 to 2023. Energy efficiency measures are typically only feasible if the demand exceeding station capacity is a small percentage of the total demand in each year. Similarly, historical zonal demand response auction data indicates that demand response is only feasible to reduce peak demand levels by single digit percentages. While distributed generation can technically be sized to accommodate any demand growth (within station short circuit and thermal limitations) this would functionally be the same as the new customer self-generating rather than seeking grid supply and is unlikely to be cost effective. The near-term timing of the demand growth is also problematic for implementing non-wires alternatives since many of the technical and regulatory barriers for implementing non-wires alternatives are still being tested.

The IRRP recommends that Hydro One Distribution install transformer fan monitoring which will increase the station capacity above forecast demand levels. Installing fan monitoring is an inexpensive method to increase the station LTR by enabling the use of higher thermal ratings on the existing transformers. The cost of installing fan monitoring is in the range of $1-1.5M compared to the cost of adding a new transformer which would be greater than $3M. Fan monitoring will increase the station capacity from approximately 10 MW today to 16 MW.

If additional capacity needs arise, a second transformer at the station which currently acts as a spare can be brought into service, but no recommendation beyond the fan monitoring is required based on the current forecast.

7.1.4 Options and Recommendations for Kenora MTS

Kenora MTS serves the City of Kenora and is expected to reach capacity in 2029 with a moderate annual growth rate of 1.25%. The station has an LTR of 23.4 MW and demand will exceed the LTR by approximately 4 MW by the end of the forecast horizon (2040).

Non-wires alternatives are promising for addressing the Kenora MTS station capacity need. The magnitude of the need relative to the total demand is moderate which makes targeting load modifying non-wires alternatives like energy efficiency and demand response feasible. The timing of the need is in the mid-term, so the forecast confidence is reasonably high while still having adequate lead time to demonstrate the efficacy of relatively untested non-wires alternatives and navigate technical and regulatory barriers. The timing of the need also means that lessons learned from the IESO's York Region Non-Wires Alternative Demonstration Project can be leveraged for implementing non-wires alternatives for Kenora MTS.

The following subsections discuss the wires options for Kenora MTS, non-wires alternatives, and recommendations.

7.1.4.1 Wires Options

There are two high-level wires options:

- Expand Kenora MTS with an additional transformer and associated protections, control, and structures at a cost of approximately $5M. This can be accommodated on existing land owned by the distributor, Synergy North, within the station. This option assumes that feeder loads can be rebalanced and servicing these loads on existing distribution system infrastructure is possible.

- Construct a new substation located across the city from the existing station at a cost of approximately $30M. The new station would be supplied from Rabbit Lake SS.

The existing Kenora MTS station is located on the northern edge of the city. The proposed new substation would be located on the far west side of the city and, in addition to addressing station capacity needs, would provide substantial distribution system benefits by reducing the length of feeders required to reach customers and improving voltage and frequency regulation. The long feeders to the western parts of the system currently experience voltage and frequency issues especially during outages requiring parts of the distribution system to be resupplied from alternate feeders. Synergy North is also aware of significant development interest along the western outskirts of the city, but no formal agreements have been finalized. A new station would provide a supply point close to these customers and improve distribution system performance.

A new station would also provide a redundant transmission supply point that is connected to a different bus/breaker at Rabbit Lake SS than the existing station. If a new station is built, the distribution system could be designed with tie points and reclosers to enhance the overall reliability across Kenora.

The distribution system benefits above have only been qualitatively described in the IRRP. As discussed in the following subsections, the cost effectiveness of the non-wires alternatives may hinge on whether they can provide similar distribution system benefits as a new station. Future analysis by Synergy North should further quantify the value of these benefits.

7.1.4.2 Non-wires Alternatives

Three non-wires alternatives for Kenora MTS were identified and sized according to the characteristics of the hourly demand profile described in Section 5.6:

- A 4 MW gas generation facility (aero engine). The cost estimate for gas generation is based on the IESO's internal benchmark cost reports. To estimate its contribution to provincial system adequacy, its effective capacity was assumed to be 93% of its installed capacity, which is the lesser of its unforced capacity and the zonal capacity maximums reported in the 2021 IESO Annual Planning Outlook.[22]

- A 6-hour 4 MW (24 MWh) battery. The cost estimate for battery storage is based on data from the National Renewable Energy Laboratory. Note that local generation (e.g., wind or solar) was not required to complement the battery due to the relatively low energy requirement (i.e., the battery can be recharged from existing grid power when it is not needed).

[22] The 2021 Annual Planning Outlook is available on the IESO's Planning and Forecasting webpage.

- A combination of energy efficiency measures and demand response. The availability and cost of incremental energy efficiency measures (i.e., in addition to the conservation and demand management programs already included in the demand forecast) are based on the IESO's 2019 Conservation Achievable Potential Study[23]. The 2019 Achievable Potential Study and incremental energy efficiency savings for Kenora MTS are further described in Appendix E. Demand response costs are estimated from average capacity auction values from 2018-2021 for the Northwest zone.

The net present value (NPV) of each wires and non-wires alternative's cost is shown in Table 7-1. The NPV includes the levelized unit energy cost as well as bulk system energy and capacity costs and benefits associated with each option over a 45-year asset life (which is typical for station equipment).

Table 7-1 | Kenora MTS Wires and Non-wires Alternative Costs

Option	Cost NPV ($2021 Real)
Expand Kenora MTS	$4 M
New Station	$25 M
4 MW Gas Generation	$22 M[24]
24 MWh Battery Storage	$10 M[24]
Combination of Energy Efficiency and Demand Response	$1-9 M[25]

7.1.4.3 Recommendation

The cost of the non-wires alternatives generally falls between the cost of expanding the existing station and a new station (which also improves reliability and performance on the distribution system). Therefore, the decision to pursue non-wires alternatives versus traditional wires options rests on distribution system benefits that can be realized by each option. For example, battery storage can be sited on the distribution system such that it improves voltage regulation along lengthy feeders. If the value of the distribution system benefits is greater than the cost difference between the battery and station expansion, the battery may be the most cost-effective solution for ratepayers overall.

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[23] The 2019 Conservation Achievable Potential Study can be found on the IESO's website.

[24] Assumes full (unforced capacity) credit for system capacity value. Actual cost could be higher depending on the deliverability of the NWA resource.

[25] Cost ranges from $1-9 M depending on whether the energy efficiency measures are part of provincially cost-effective CDM (i.e implemented through the IESO's Local Initiative Program) or if they are incremental to provincially cost-effective CDM.

The technologies, regulatory framework, and protocols required to implement dispatchable non-wires alternatives (e.g., batteries, gas generation, or demand response) for the purpose of meeting local capacity needs are still being tested. The IESO's York Region Non-Wires Alternative Demonstration Project[26] is currently exploring market-based approaches to secure energy and capacity services from distributed energy resources (DERs) for local needs. There is a window of opportunity between today and 2029 when the Kenora MTS capacity need arises to leverage learnings from the York Region Pilot and further refine the procurement and operation of non-wires alternatives for Kenora MTS.

Since there are no upstream constraints on the transmission system requiring further regional coordination, the IRRP recommends that Synergy North lead further NWA analysis and refinement as part of local planning. Synergy North should monitor load growth at Kenora MTS to determine when a firm commitment for additional capacity is required and implement non-wires alternatives if they remain feasible and cost-effective. Furthermore, the IESO will consider Kenora MTS as a potential focus area for the Local Initiatives Program[27] under the 2021-2024 Conservation and Demand Management Framework. The IESO will collaborate with Synergy North in 2023 as further details for the next round of the Local Initiatives Program become available. In addition to the energy efficiency measures that may result from the IESO's Local Initiative Program, Synergy North may also use the Ontario Energy Board's Conservation and Demand Management Guidelines[28] to leverage distribution rates for non-wires alternatives.

7.2 Options for Improving Customer Reliability at Fort Frances TS

As discussed in Section 2.1.4, the IRRP will not make a specific recommendation for improving customer reliability since Fort Frances Power's roadmap for Fort Frances MTS is still under development. However, this section will document the options considered during the IRRP process and the IRRP recommends that Fort Frances Power and Hydro One continue to collaborate and select a preferred option in local planning.

The Fort Frances TS 115 kV station layout and connection to Fort Frances MTS is shown in Figure 7-1. The 115 kV side of Fort Frances TS is comprised of a 6-breaker ring bus with connections to the station's two autotransformers and circuits K6F, F3M, F2B, and F1B. Fort Frances MTS is currently connected to the L1-bus (which connects to F1B) and is physically located immediately adjacent to Fort Frances TS. Transmission outages to F1B and the L1 bus have accounted for 90% of Fort Frances Power's customer interruptions over the last 10 years. Therefore, Hydro One has proposed reconfiguration options with the goal of reducing Fort Frances MTS' exposure to transmission outages.

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[26] For more information on the pilot and latest developments, please see the York Region Non Wires Alternatives Demonstration Project engagement webpage.

[27] For more information on the Local Initiatives Program, please see the Save ON Energy Local Initiatives webpage and the 2021-2024 Conservation and Demand Management Framework webpage.

[28] More information about the Conservation and Demand Management Guidelines is available on the OEB's website (link).

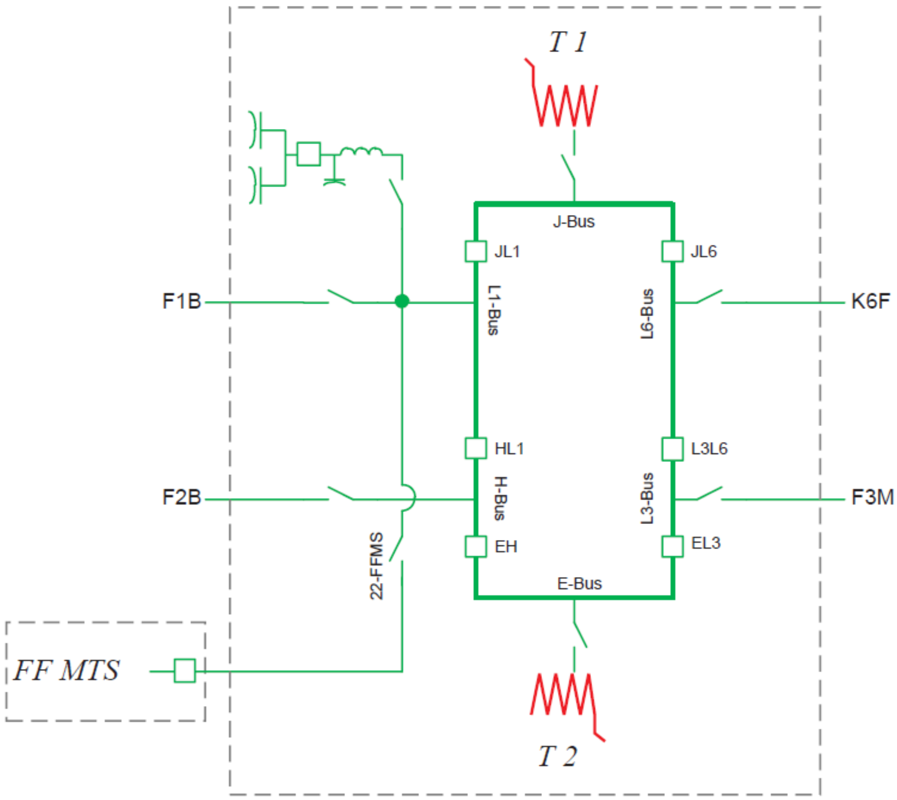

Figure 7-1 | Fort Frances TS 115 kV Single Line Diagram

The following options, in order of increasing complexity and cost, were contemplated:

- Replace the existing 22-FFMS air-break switch with an interrupter switch (still connected to F1B) and install a second interrupter switch to connect Fort Frances MTS to F2B. One of the two switches would be operated normally open, but the switches would allow Fort Frances MTS to be transferred between F1B and F2B to avoid any supply interruptions during planned outages on either of the two circuits or buses.
- Install a new 115 kV breaker on the L1 bus and move the Fort Frances MTS termination between this new breaker and the HL1 breaker. This would form a 7-breaker ring bus and Fort Frances MTS would have its own position separate from any other circuit.

- Install a second breaker at Fort Frances MTS and connect it to the H-bus via a new air-break switch. Since Fort Frances MTS already has two transformers, if both Fort Frances MTS breakers are normally closed, this configuration could provide fully redundant transmission supply. However, the feasibility of having both supply points normally closed is still being reviewed; a normally open point may be required to manage short circuit levels. If either the L1-bus or H-bus supply points needs to be operated normally open, this option would be functionally the same as the first option (but more expensive).

8. Supply to the Ring of Fire

The Ring of Fire is a remote area covering 5000 km^2 located 500 km north of Thunder Bay with rich deposits of critical minerals.[29] There is strong interest in developing mining activities in this area, however as it is located far from established infrastructure, it is currently without all-season road access or grid power supply. Transmission supply to the Ring of Fire was contemplated in the 2015 cycle of regional planning for Northwest Ontario. With renewed interest in developing the Ring of Fire from both government and mining companies, the IESO is updating its Supply to the Ring of Fire study in parallel with the ongoing Northwest IRRP. This report provides an update on preliminary findings as of Q4 2022 including:

- Transmission supply options and high-level cost estimates;
- Key opportunities for alignment that should be considered in the decision to pursue transmission supply to the Ring of Fire as well as its routing and connection point;
- Avoided diesel system costs from connecting remote communities to the grid via a transmission line to the Ring of Fire; and
- Greenhouse gas reductions associated with connecting remote communities and Ring of Fire mines to the grid, as opposed to self generation.

Note that the decision to pursue transmission supply to the Ring of Fire ultimately lies with mining companies and remote communities as the direct beneficiaries of such a project, and with the provincial and federal governments to advance broader policy objectives. The purpose of the renewed Supply to the Ring of Fire study is to help inform government policy and potential customers seeking connection.

8.1 Background

A map of the Ring of Fire area and nearby features of interest are shown in Figure 8-1. Interest in developing the Ring of Fire has varied over the years and there is a high degree of uncertainty in the eventual mining sector electrical demand that may materialize. However, with the current focus on developing critical minerals to support decarbonisation, interest in developing the Ring of Fire area is growing.

[29] Ontario's critical mineral list can be found in the 2022-2027 Critical Mineral Strategy is available on Ontario's Mining and Minerals website.

In addition to potential mining loads, there are five off-grid Matawa First Nation communities in the vicinity of the Ring of Fire. These communities rely on diesel generation systems that are expensive to operate, produce environmental pollutants, and may constrain the communities' growth. Enabling grid supply for these communities is an important factor contributing to the overall rationale for transmission supply to the Ring of Fire. The transmission supply routing and connection point to the existing electricity system should also consider the significant potential for hydro generation in the area which may be able to connect to the grid via the transmission line to the Ring of Fire.

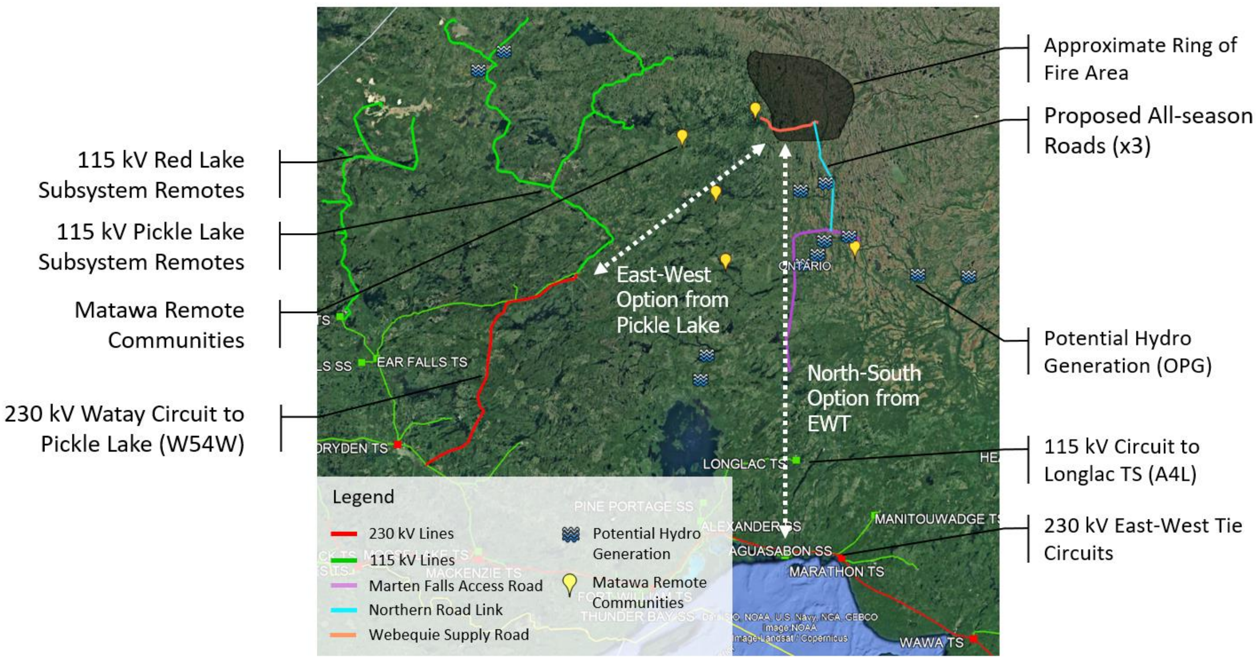

Figure 8-1 | Ring of Fire and Surrounding Area Map

Transmission supply to the Ring of Fire was contemplated in the 2015 North of Dryden IRRP and the 2016 Greenstone-Marathon IRRP. The North of Dryden IRRP outlined potential transmission supply options with the goal of connecting remote communities as well as serving mining electricity demand at the Ring of Fire if it were to materialize. This plan contemplated reinforcing the existing transmission system from the Dryden area to Pickle Lake and building a new transmission line from Pickle Lake to the Ring of Fire. The North of Dryden IRRP, in conjunction with the 2014 Remote Connection Plan, culminated in the indigenous-led Wataynikaneyap Transmission Project.

The Wataynikaneyap Transmission Project includes a new 230 kV line from Dinorwic Junction (near Dryden) to Pickle Lake as well as 115 kV transmission lines extending north of Pickle Lake and Red Lake to connect remote communities. The Matawa area remote communities chose not to participate in the Wataynikaneyap Transmission Project and no transmission lines were built from Pickle Lake to the Matawa communities or the Ring of Fire. This transmission supply option to the Ring of Fire is referred to as the East-West option in Figure 8-1.

The Greenstone-Marathon IRRP extended this analysis to consider potential cost optimization opportunities between new customers in the Greenstone area and remote communities/mines at the Ring of Fire. This entailed a North-South transmission supply option extending from the existing East-West Tie circuits northwards through Greenstone (which is electrically supplied from Longlac TS) and onwards to the Ring of Fire. The largest new customer in the Greenstone area at the time choose to self-generate instead of pursuing transmission supply and the North-South transmission supply option did not proceed.

To date, there have been no firm commitments from customers seeking transmission connection in the Ring of Fire area.

8.2 Policy Drivers and Demand Forecast

Enabling development in the Ring of Fire area is an important policy objective for the provincial government. Ontario's Critical Mining Strategy[30] identifies the Ring of Fire as a "priority project" and a "transformative opportunity for unlocking multi-generational development of critical minerals." The strategy also highlights the importance of Ontario's relatively clean electricity system for enabling development of lower-emissions mining compared to other jurisdictions.

The province has also expressed support for a "Corridor to Prosperity" comprised of three proposed all-season roads led by First Nations partners that connects to the existing highway system and extends northwards towards the Ring of Fire. These proposed roads include the Marten Falls Community Access Road, Webequie Supply Road, and Northern Road Link. The proposed roads are at various stages in their provincial and federal Environmental and Impact Assessments. Taken together, they would provide a continuous all-season transportation corridor to the Ring of Fire that would be necessary to facilitate mining development. Ontario has committed $1 billion to support these road infrastructure projects on the basis that federal contributions will match provincial commitments.

There is a high degree of uncertainty in terms of both the magnitude and timing of mining electricity demand at the Ring of Fire. The IESO's latest mining demand forecast includes approximately 30 MW of electricity demand associated with two proposed mining projects. The 2015/6 IRRP forecasts included up to 70 MW of demand at the Ring of Fire but some proponents have since walked away from their development plans. If transmission and

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[30] The 2022-2027 Critical Mineral Strategy is available on Ontario's Mining and Minerals website.

transportation infrastructure were developed, mining demand would almost certainly be much higher than currently forecast. As of January 2022, there are approximately 26,000 active mining claims held by 15 companies in the Ring of Fire. The IESO will continue monitoring development plans and intends to update the mining forecast in Q1 2023 to better capture Ring of Fire growth scenarios.

The five Matawa area remote communities have a total demand of approximately 4 MW today and are forecast to grow at 4% per year.[31] This forecast was last updated in 2019 and will be updated as new information becomes available.

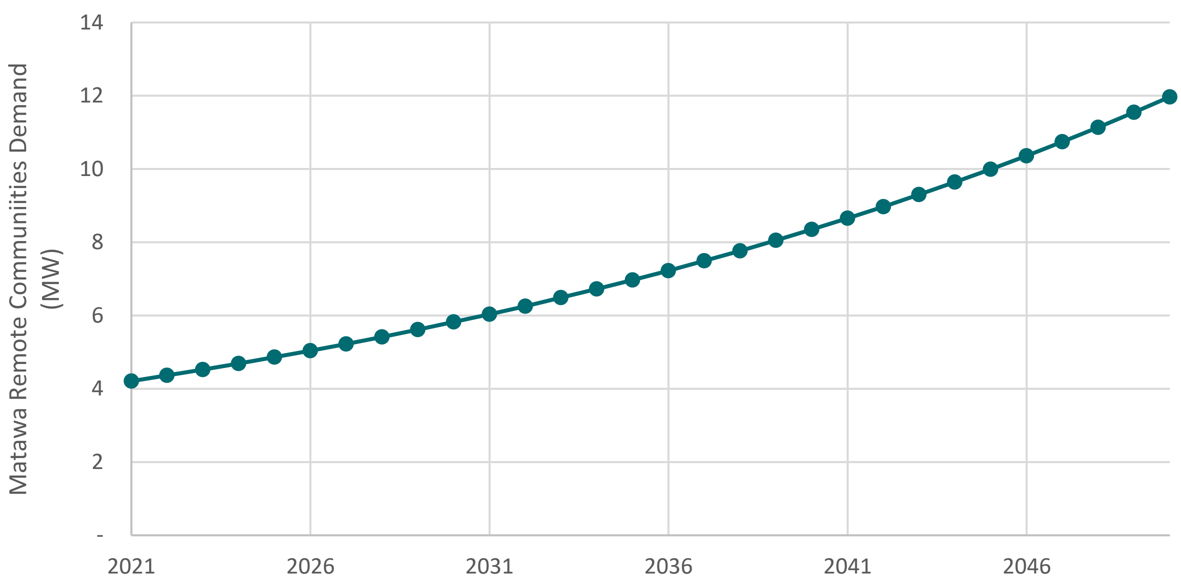

Figure 8-2 | Matawa Remote Communities Demand Forecast

[31]The forecast 4% growth rate reflects potential demand growth if the remote communities are grid connected and no longer constrained by diesel supply capacity.

8.3 Transmission Supply Options and Cost Estimates

As discussed in Section 8.1, at a high level, there are two transmission supply options to the Ring of Fire that could be pursued: a North-South option connecting to the East-West Tie circuits between Marathon and Thunder bay and an East-West option connecting to the new Wataynikaneyap TS near Pickle Lake. The conceptual electrical elements of each option are listed in Table 8-1. Note that at this stage, no detailed engineering design or routing work has been performed. The transmission options are presented here for discussion purposes and to facilitate high-level cost estimation (-50% to +100%).

The North-South option is estimated to cost between $860M and $1.08B while the East-West option is estimated to cost between $600M and $780M ($2022 real, overnight capital cost). The cost ranges reflect uncertainty in the final station configurations as well as in the per unit (km) cost of transmission lines which can vary depending on the technology type and geography. These cost estimates are not inclusive of step-down transformer stations at the loads themselves nor reactive compensation devices which will depend on the magnitude of the demand. Note that material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs.

Table 8-1 | Ring of Fire Transmission Option Conceptual Elements

Transmission Supply Option	Element #	Description	Length (km)	Cost ($2022 real)
North-South	1	230 kV single circuit line from East-West Tie circuits to Longlac	120	$170-215M
	2	New stations at East-West Tie connection point[32] and Longlac (to enable connection to A4L);	N/A	$115-125M
	3	230 kV single circuit line from Longlac to McFaulds Lake; roughly parallel to proposed roads	410	$575-740M
East-West	1	230 kV single circuit line from Wataynikaneyap TS near Pickle Lake to McFaulds Lake; roughly along route envisioned in the 2014 Remote Connection Plan	370	$580-745M
	2	Wataynikaneyap TS modifications	N/A	$20-30M

[32] Connecting the Ring of Fire line directly to East-West Tie lines between Lakehead TS and Marathon TS minimizes costs since it is the closest 230 kV supply point to the Ring of Fire. However, connecting to only one (or any subset) of the four parallel East-West Tie lines will unbalance flows between Marathon TS and Lakehead TS and may decrease the overall transfer capability of the East-West Tie. Future studies should weigh the costs and benefits of connecting to either Lakehead TS or Marathon TS versus a new junction and/or switching station on the East-West Tie.

While the East-West option is less expensive than the North-South option, it would provide less incremental capacity to supply load and would also increase exposure to outages. The load meeting capability for a radial expansion of the transmission system like the Ring of Fire is typically constrained by thermal, voltage, and load security limits. The thermal rating of a 230 kV single circuit line is unlikely to be constraining; as an example, a single East-West Tie circuit has a continuous rating of approximately 320 MW in the summer and 390 MW in the winter. This far exceeds the current known mining and remote community demand forecast. Voltage limits can be managed by installing voltage regulation devices at the loads and can be sized according to the expected demand, however this would add incremental cost and operational complexity. Load security limits, however, may become the most limiting factor depending on future mining developments.

Ontario Resource and Transmission Assessment Criteria (ORTAC) Section 7.1 load security criteria specifies the maximum amount of load that can be interrupted after certain contingencies. For the loss of a single element (i.e. single circuit supply to the Ring of Fire), no more than 150 MW may be interrupted. This limits the total load served on the North-South option to 150 MW. The East-West option is connected downstream of the new single circuit Wataynikaneyap line (W54W). The total load served by W54W is also limited to 150 MW including the all existing loads and their growth, new mining customers along W54W, and the Ring of Fire and Matawa communities. Existing load served on W54W totals approximately 45 MW today and is expected to grow to 80 MW by 2040. While the remaining room is sufficient for serving the currently forecast demand at the Ring of Fire (30 MW mining plus Matawa area communities), it leaves relatively little room to accommodate additional development. Furthermore, the IESO is aware of several additional mining projects potentially seeking connection along W54W. While these projects are not yet certain enough to be included in the IRRP reference forecast, they could significantly reduce the available capacity for growth at the Ring of Fire.

While not addressed by ORTAC criteria, another consideration is the level of exposure to outages. The East-West option would involve connecting the Ring of Fire and Matawa communities to a radial system that already spans several hundred kilometers of transmission lines (W54W and D26A). Each time any part of this system is faulted (e.g., in an electrical storm or fire), the whole system is removed from service until the fault can be addressed. By comparison, the North-South option can be connected to the East-West Tie (or nearby station) which are more robust and has redundant supply.

Due to the uncertainty in future mining developments, it is too early to rule out the East-West option at this time. However, the potential capacity constraints and customer reliability impacts related to the East-West option should be considered when selecting a preferred transmission option. The next section discusses opportunities for alignment and further considerations that may impact the preferred transmission option.

8.4 Opportunities for Alignment

A decision to pursue transmission supply to the Ring of Fire, and decisions on its preferred routing, should consider alignment with four opportunities in addition to supplying mining demand at the Ring of Fire:

- Supplying Matawa Remote Communities
- Enabling potential hydro generation
- Improving supply to Longlac
- Co-locating with transportation corridor

These opportunities for alignment are discussed in turn below.

8.4.1 Supplying Matawa Remote Communities

There are five Matawa indigenous remote communities in the vicinity of the Ring of Fire:

- Webequie
- Nibinamik
- Neskantaga
- Marten Falls
- Eabametoong

These communities were previously identified as economic for grid connection in the 2014 Remote Connection Plan but elected not to participate in the Wataynikaneyap Transmission Project. The 2014 Remote Connection Plan found that it was more cost-effective to supply the communities via a single circuit 115 kV transmission line (either from Pickle Lake or the East-West Tie circuits) than continued reliance on off-grid diesel generation systems. Transmission supply to the Ring of Fire could also enable connection of the Matawa remote communities. Both the North-South and East-West transmission options would serve this purpose. Updated potential avoided diesel generation system costs are discussed in Section 8.4.2.

Note that the decision to pursuing grid connection is up to the communities. The IESO will continue to engage with the Matawa communities to inform future studies. Furthermore, grid connection of remote communities does not preclude local energy projects such as the installation of distributed generation and storage. The IESO continues to support broad equitable participation in Ontario's energy sector through its Energy Support Programs including the Indigenous Energy Projects (IEP) Program[33] which provides funding support to First Nation and Metis communities to assess and develop energy projects and partnerships.

8.4.2 Enabling Hydro Generation

In Jan 2022, the Ontario government asked Ontario Power Generation to examine opportunities for new hydroelectric development in northern Ontario. New hydroelectric generation could address the growing long-term electricity needs forecast for the province, with the potential for economic benefits for local and Indigenous communities in the north. Ontario Power Generation has shared this work with the Ministry of Energy and the IESO so that it can be considered as part of the IESO's work towards developing an achievable pathway to zero emissions in the electricity sector. Development of transmission supply to the Ring of Fire should consider the connection of potential hydro generation in the area.

There is significant hydroelectric generation potential in the vicinity of the Ring of Fire. Due to the geographic distribution of these potential generation facilities, the North-South transmission option is better suited than the East-West option to connect these facilities on the way to the Ring of Fire. Furthermore, the North-South option connects to a more robust point in the bulk transmission system which may result in fewer deliverability constraints and lower overall losses. The Ring of Fire North-South transmission line is not necessarily the optimal connection point for potential hydro generation near the Ring of Fire. Other connection options, to Pinard TS for example, may reduce the overall bulk system reinforcements needed to deliver the hydro generation capacity to southern Ontario. However, connecting to the Ring of Fire transmission line could significantly reduce the length of connection lines required for these potential hydro generators and future studies should consider the synergies between Ring of Fire transmission supply and enabling the connection of potential hydro generation.

8.4.3 Improving Supply to Longlac

The existing radial 115 kV circuit, A4L, to Longlac TS is near capacity and customers have expressed concern about poor reliability due to long and frequent outages. While no firm growth plans or new customer connection requests were received during this IRRP, there continues to be a high degree of interest for mining and industrial developments in the Greenstone and Geraldton areas supplied by A4L. There are also existing customers along A4L who have elected to self-generate rather than connect to the transmission system due to capacity constraints.

A4L refurbishment is underway and distance-to-fault relays have been installed which should decrease the frequency of outages and improve restoration times. However, these improvements do not increase the load meeting capability on A4L and, as with many other areas in the Northwest region, growth can materialize quickly.

[33] For more information, please visit the Indigenous Energy Projects Program webpage.

The North-South transmission option passes directly by Longlac TS and could help increase capacity and provide a secondary supply path to further improve reliability. The North-South option conceptual elements in Table 8-1 includes a 230/115 kV transformer station at Longlac for this purpose. Note that the East-West option is not suitable for reinforcing Longlac.

8.4.4 Co-locating with Transportation Corridor

The proposed Marten Falls Community Access Road, Webequie Supply Road, and Northern Road Link will provide a continuous all-season transportation corridor to the Ring of Fire. While detailed routing has not yet been performed, the North-South transmission option is well aligned with the proposed roads. The line length determined for the North-South option in Table 8-1 assumes that the transmission corridor runs parallel to the proposed roads wherever possible but the potential cost savings associate with colocation has not been factored into the transmission cost estimate yet. This likely overestimates the cost of the North-South transmission option compared to the East-West option; future studies should conduct more detailed engineering design and routing analysis to better quantify the benefits of colocation.

Co-locating linear infrastructure is consistent with provincial policy as articulated in Section 1.6.8 of the 2020 Provincial Policy Statement[34] and may help reduce environmental impacts. The roads would also provide easier access to the transmission line which could simplify construction as well ongoing operation and maintenance. Note that there are no proposed all-season roads along the East-West option route.

8.5 Avoided Matawa Communities Diesel System Costs

The Matawa remote communities are currently supplied by remote on-site diesel generation which is costly to operate. Up to 70% of the fuel must be flown in when winter roads are not available contributing to high costs and increased emissions from fuel transport. The costs of supplying electricity from remote diesel generation systems versus the grid over the first 20 years of transmission connection are shown in Figure 8-3. The net present value of remote diesel generation costs is estimated to be $446M over this period, while serving the same load from the provincial grid is estimated to be roughly $35M.[35] These net present values are expressed in real dollars in the year when transmission connection is hypothetically brought in-service. For the purpose of this assessment, it was assumed that transmission connection occurs in 2030 given the typical 7-year lead time of new transmission projects.

[34] The 2020 Provincial Policy Statement can be found on the Ontario government's Land Use Planning webpage.

[35] The cost of serving loads on the provincial grid is solely based on the system's marginal cost of energy. It does not include cost of transmission connection itself. Connecting remote communities is one of multiple potential benefits (other benefits include supplying mining loads and enabling hydro generation) that contribute towards a rationale for transmission supply. The cost of transmission supply should be compared against this full suite of benefits.

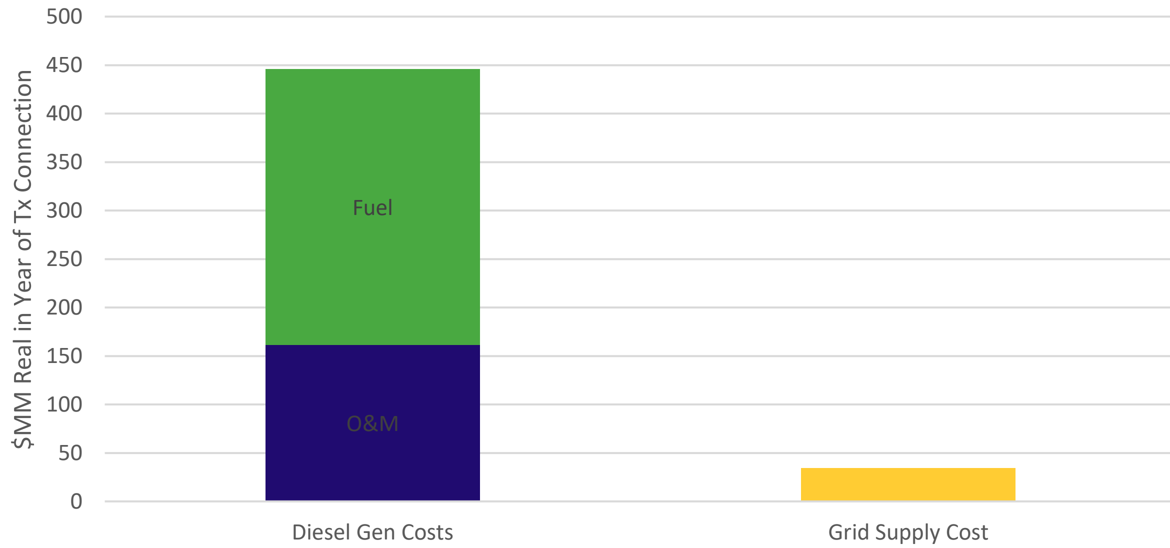

Figure 8-3 | NPV of Electricity Supply Costs from Diesel Generation versus the Provincial Grid for Matawa Remote Communities over the First 20 Years of Grid Connection

The cost of continuing to supply electricity to the remote Matawa communities by local diesel generation was estimated using the IESO's internal fuel forecast and aggregated cost data for remote communities served by Hydro One Remote Communities.[36] Generally speaking, economic and cost assumptions were consistent with the 2014 Remote Connection Plan adjusted for inflation. The cost of supplying electricity from local diesel generation is comprised of two components:

- Fuel costs including the cost for the fuel itself, winter road/air transportation, and the cost of carbon;
- Operating and maintenance costs estimated from historical revenue requirement and rate application regulatory submissions as a percentage of fuel costs.

[36] Not all Matawa communities are served by Hydro One Remote Communities. For communities served by Independent Power Authorities for which cost data was not directly available, system costs were estimated based the size of their load and Hydro One Remote Communities' system costs.

Of the $446M net present value, $284M is associated with fuel costs and $162M with operating and maintenance costs. Note that this cost estimate does not include the capital costs associated with expanding existing diesel systems to meet future capacity growth. This enables an apples-to-apples comparison with the cost of grid electricity which also did not include the incremental resource capacity cost of serving the newly connected remote communities. Furthermore, since the incremental capacity requirement is dependent on the year in which transmission connection occurs and the system needs/market conditions in the period following grid connection, capital costs associated with this capacity cannot be accurately calculated today. Future studies should refine the consideration of capacity costs when there is more certainty on when transmission supply will proceed.

The cost of serving Matawa remote communities should they be connected to the provincial electricity grid was based on the system marginal cost forecast in the 2021 Annual Planning Outlook.

8.6 Avoided Greenhouse Gas (GHG) Emissions

Avoided GHG emissions was estimated for the Matawa communities and the future mining load through the comparison of emissions on the electricity system (consistent with the 2021 Annual Planning Outlook emission rate per MWh) versus diesel generation for remote communities and natural gas generation for mining loads.[37]

The GHG reduction associated with connecting Matawa communities depends on the forecast demand levels and growth rate when transmission connection occurs. Consistent with the diesel system cost savings estimates in the previous section, transmission connection was assumed to occur in 2030. On average, over the first 20 years of transmission connection (i.e. 2030-2049), GHG reductions are expected to be approximately 27,000 tCO2e per year.

The GHG reduction associated with mining loads depends on the amount of demand that materializes. As discussed in Section 8.2, there is a high degree of uncertainty in terms of both the magnitude and timing of this demand. For illustrative purposes, if 30 MW of demand materializes (consistent with demand from known projects), GHG reductions would total 68,000 tCO2e per year. If 70 MW of demand materializes (consistent with demand from the 2015 IRRP forecasts), GHG reductions would total 160,000 tCO2e per year. The true avoided GHG emissions associated with connecting mining loads instead of on-site generation could be much higher given the large number of active mining claims in the Ring of Fire.

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[37] The natural gas generation was assumed to be a combined cycle gas turbine (CCGT) facility with a heat rate of 7.265 MW/MMbtu and a natural gas emission intensity of 53.157 kgCO2e/MMbtu. For diesel generation emissions, the Hydro One Remote Communities fleet average generator efficiency and a diesel emission intensity of 75.22 kgCO2e/MMbtu was assumed.

8.7 Next Steps

The sections above provide an overview of preliminary findings to date of the Supply to the Ring of Fire Study and highlights some areas of uncertainty that will require further investigation. The IESO will continue the Supply to the Ring of Fire Study in 2023. The scope, timing, and engagement process will evolve with government policy direction. The IESO will share updates with the Working Group to inform upcoming regional planning activities such as the Regional Infrastructure Plan.

9. 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 this Northwest IRRP.

9.1 Engagement Principles

The IESO's engagement principles[38] 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.

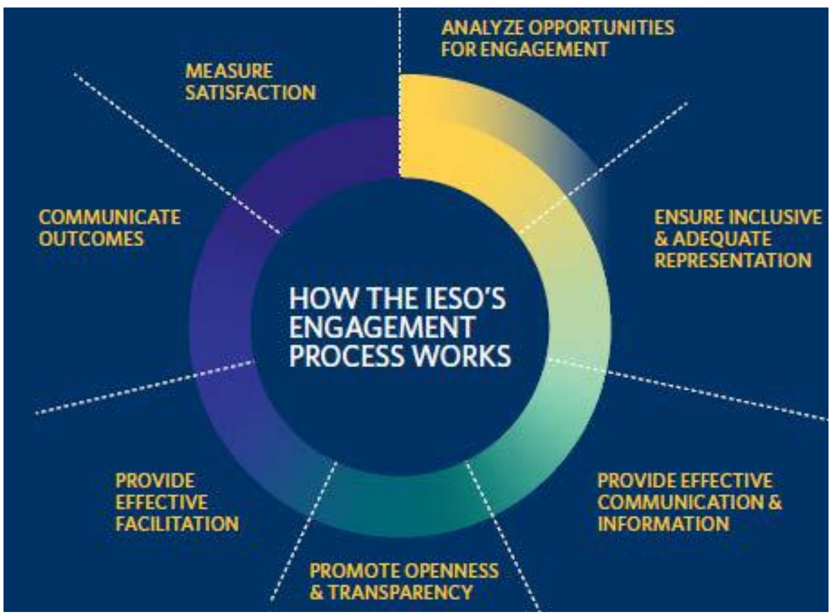

Figure 9-1 | IESO's Engagement Principles

[38] https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

9.2 Creating an Engagement Approach for the Northwest

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 to provide meaningful input on the development of the IRRP for the region.

Creating the engagement plan for this IRRP involved:

- Targeted discussions to help inform the engagement approach for this planning cycle;
- Communications and other engagement tactics to enable broad participation, using multiple channels to reach audiences; and
- Identifying specific stakeholders and communities who may have a direct impact in this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region.

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

- A dedicated webpage[39] on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email and through the IESO weekly Bulletin;
- Public webinars;
- Targeted discussions sessions;
- Face-to-face meetings; and
- One-on-one outreach with specific communities and stakeholders to ensure that their identified needs are considered (see Sections 9.4 and 9.5).

[39] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Regional-Electricity-Planning-Northwest-Ontario

9.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this round of planning, leveraging existing relationships built through the previous planning cycle. This started with the Scoping Assessment Outcome Report for the Northwest region. An invitation was sent to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues to announce the commencement of a new regional planning cycle and invite interested parties to provide input on the Northwest Scoping Assessment Report before it was finalized.

Feedback was received and focused on the need to ensure that municipal energy planning, including the need to recognize climate change priorities, as well as economic development and industrial growth (including forestry and mining) were in scope of the development of the IRRP. In addition, reliability remained a paramount concern within this region. Along with a response to the feedback received, the final Scoping Assessment was posted on January 13, 2021, which identified the need for a coordinated regional planning approach across the Northwest region – particularly important since the previous planning cycle targeted regional plans within five identified sub-regions.

Following the finalization of the Scoping Assessment, outreach then began with targeted municipalities to inform early discussions for the development of the IRRP including the IESO's approach to engagement. The launch of a broader engagement initiative followed with an invitation to IESO subscribers of the Northwest planning region as well as all identified municipalities and Indigenous communities to ensure that all interested parties were made aware of this opportunity for input. Four public webinars were held at key stages during the IRRP development to give interested parties an opportunity to hear about progress and provide comments on various components of the plan.

All these engagement sessions received strong participation with a cross-representation from stakeholders and community representatives. Feedback was received as a result each engagement meeting which was considered in each of the stages in the IRRP development.

The public webinars invited input on:

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

2. The defined electricity needs for the region and potential options to meet the identified needs.

3. The analysis of options and draft IRRP recommendations.

In addition, three targeted discussions were held virtually to uncover specific feedback from communities and stakeholders on the following three topics:

1. Customer Reliability Concerns
2. Emerging Local Initiatives
3. Emerging Electricity Needs in the North of Dryden Area

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

- Given the large geographic area for this planning region, consideration throughout the engagement should be given to targeted discussions to address local reliability and priorities. Education and support should be available to enable purposeful engagement for all interested parties
- Consideration in the demand forecast should be given to local developments, growth plans and climate change goals (i.e., electrification) – particularly in communities where capacity may be limited
- Non-wires alternatives should be considered to meet needs and, in particular, climate change priorities; existing resources in the region should be considered where contracts are due to expire
- Due consideration should be given to providing capacity for new commercial and industrial (mining and forestry) growth as well as electrification of existing industry
- Opportunities for future proponents to leverage existing partnerships or create new relationships among local and Indigenous communities to have due consideration of priorities and provide business prospects, where possible

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

All interested parties were kept informed throughout this engagement initiative via email to Northwest region subscribers, municipalities, and Indigenous communities as well as the members of the Northwest Regional Electricity Network.

Based on the discussions through the Northwest IRRP engagement initiative and broader network dialogue, there is a clear interest to further discuss the potential for development of the mining sector in this region and to look for alternative energy solutions to meet local needs, particularly as communities and industries shift towards electrification. This insight has been valuable to the IESO and will help to inform future discussions to examine and consider these types of initiatives and the opportunities that they may present in future planning efforts. To that end, ongoing discussions will continue through the IESO's Northwest Regional Electricity Network to keep interested parties engaged in a two-way dialogue on local developments, priorities, and planning initiatives to prepare for the next planning cycle.

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

9.4 Bringing Municipalities to the Table

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

9.5 Engaging with Indigenous Communities

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning across Ontario. To raise awareness about the regional planning cycle in Northwest Ontario and provide opportunities to provide input, the IESO invited Indigenous communities located in or near the Northwest region to participate in webinars that were held on:

- December 8, 2020
- May 20, 2021
- September 27, 2021
- November 2, 18, 29, 2021
- April 25 and 26, 2022
- November 3, 2022

The First Nation communities that were invited to the webinars were:

- Animakee Wa Zhing No. 37
- Animbiigoo Zaagi'igan Anishinaabek
- Anishinaabeg of Naongashiing (Big Island)
- Anishinabe of Wauzhushk Onigum
- Aroland
- Bearskin Lake
- Big Grassy River (Mishkosiminiziibiing)
- Biinjitiwaabik Zaaging Anishinaabek
- Bingwi Neyaashi Anishinaabek
- Cat Lake
- Constance Lake
- Couchiching
- Deer Lake
- Eabametoong
- Eagle Lake
- Fort William
- Grassy Narrows
- Iskatewizaagegan No. 39
- Kasabonika Lake
- Keewaywin
- Kiashke Zaaging Anishinaabek
- Kingfisher Lake
- Kitchenuhmaykoosib Inninuwug
- Lac des Mille Lacs
- Lac La Croix

- Lac Seul
- Long Lake No. 58
- Marten Falls
- McDowell Lake
- Michipicoten
- Mishkeegogamang
- Mitaanjigamiing
- Muskrat Dam Lake
- Naicatchewenin
- Namaygoosisagagun
- Naotkamegwanning
- Neskantaga
- Netmizaaggamig Nishnaabeg (Pic Mobert)
- Nibinamik
- Nigigoonsiminikaaning
- Niisaachewan Anishinaabe Nation
- North Caribou Lake
- North Spirit Lake
- Northwest Angle No. 33
- Ojibway Nation of Saugeen
- Ojibways of Onigaming
- Pays Plat
- Pikangikum
- Poplar Hill
- Rainy River
- Red Rock Indian Band
- Sachigo Lake
- Sandy Lake
- Seine River
- Shoal Lake No. 40
- Slate Falls
- Wabaseemoong
- Wabauskang
- Wabigoon Lake
- Wapekeka
- Washagamis Bay (Obashkaandagaang)
- Wawakapewin
- Webequie
- Whitesand
- Wunnumin Lake

The Métis communities that were invited to the webinars were:

- MNO Atikokan Métis Council
- MNO Greenstone Métis Council
- MNO Kenora Métis Council
- MNO Northwest Métis Council (Dryden)
- MNO Sunset Country Métis Council (Fort Frances)
- MNO Superior North Shore Métis Council (Terrace Bay)
- MNO Thunder Bay Métis Council
- Red Sky Independent Métis Nation

9.5.1 Information about Indigenous Participation and Engagement in Transmission Development

By conducting regional planning, the IESO determines the most reliable and cost-effective options after it has engaged with stakeholders and Indigenous communities and publishes recommendations in the applicable regional or bulk planning report. Where the IESO determines that the lead time required to implement the recommended solutions requires immediate action, the IESO may provide those recommendations ahead of the publication of a planning report.

In instances where transmission is the recommended option, a proponent applies for applicable regulatory approvals, including an Environmental Assessment that is overseen by the Ministry of Environment, Conservation and Parks (MECP). This process includes, where applicable, consultation regarding Aboriginal and treaty rights, with any approval including steps to avoid or mitigate impacts to said rights. MECP oversees the consultation process generally but may delegate the procedural aspects of consultation to the proponent. Following development work, the proponent will then apply to the OEB for approval through a Leave to Construct hearing and, only if approval is granted, can it proceed with the project. In consultation with MECP, project proponents are encouraged to engage with Indigenous communities on ways to enable participation in these projects.

There are no new transmission projects recommended as a result of this Northwest planning initiative.

10. Conclusion

The Northwest IRRP identifies electricity needs in the region over the 20-year period from 2021-2040, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. The IESO will continue to participate in the 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.

In the near term, the IRRP recommends new and/or upgraded stations to address station capacity needs at Crilly DS and Margach DS, further refinement of non-wires alternatives at Kenora MTS, reconfiguration of Fort Frances TS to improve customer reliability at Fort Frances MTS, and additional reactors at or near Pickle Lake SS to manage high voltages so that E1C can be operated normally open. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

The IRRP recommends that the Working Group monitor growth, particularly in the Red Lake and Fort Frances areas. The IRRP studied high growth sensitivities to establish load meeting capabilities in these areas against which growth should be monitored to determine when future regional planning activities should be triggered. The IESO will update its mining sector demand forecast in early 2023 and provide updates to the Working Group. Electricity demand at White Dog DS and Marathon DS should also be monitored to confirm the timing of station capacity needs emerging in the 2030's. No firm recommendations are required for these potential long-term needs at this time.

The IESO will continue the Supply to the Ring of Fire Study in 2023. The scope and timing will evolve with government policy direction and the IESO will share updates with the Working Group to inform upcoming regional planning activities.

The Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. If 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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