Sudbury/Algoma Region

Scoping Assessment Outcome Report

January 24, 2026

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1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's (OEB or Board) regional planning process and sets out the planning approach to address electricity needs that have been identified in the Sudbury Algoma Region. The OEB started regional planning in 2011 and endorsed the Planning Process Working Group's Report to the Board in May 2013. The Board formalized the process and timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The current cycle of regional planning for the Sudbury Algoma Region started in June 2025. The Needs Assessment (NA) is the first step in the regional planning process and was carried out by the Sudbury Algoma Technical Working Group (TWG) led by Hydro One Networks Inc. (Hydro One). This report was finalized on October 24, 2025 and flagged several needs requiring further regional coordination as well as a few needs to be addressed by local planning. This information was an input to this Scoping Assessment Outcome Report.

As part of the Scoping Assessment, the TWG reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach to address them, including:

- An Integrated Regional Resource Plan (IRRP) – through which a greater range of options, including non-wires alternatives, are to be considered and/or closer coordination with communities and stakeholders is required
- A Regional Infrastructure Plan led by the transmitter – which considers more straight-forward wires only options with limited engagement
- A Local Plan undertaken by the transmitter(s) and affected local distribution company or companies (LDC) – for which no further regional coordination is needed

Based on this assessment, the TWG recommends proceeding with an **Integrated Regional Resource Plan (IRRP)** for the Sudbury Algoma region. This recommendation is driven by several specific needs identified through stakeholder engagement and previous planning cycles.

The structure of this Scoping Assessment Report is outlined below:

- Section 2 lists the Technical Working Group
- Section 3 provides an overview of the region, the previous regional planning cycle, and major transmission reinforcements since the previous cycle
- Section 4 summarizes the new and updated needs as described in the Needs Assessment
- Section 5 describes the criteria used to select a regional planning approach and specifies the scope of the IRRP

Appendix 1 defines the acronyms used in this document and Appendix 2 establishes the draft Terms of Reference for the IRRP and the composition of the IRRP Technical Working Group.

2. Technical Working Group

The Scoping Assessment was carried out with the following participants:

- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. Transmission (HONI Tx)
- Hydro One Distribution (HONI Dx)
- Greater Sudbury Hydro
- North Bay Hydro

3. Overview of Region and Background

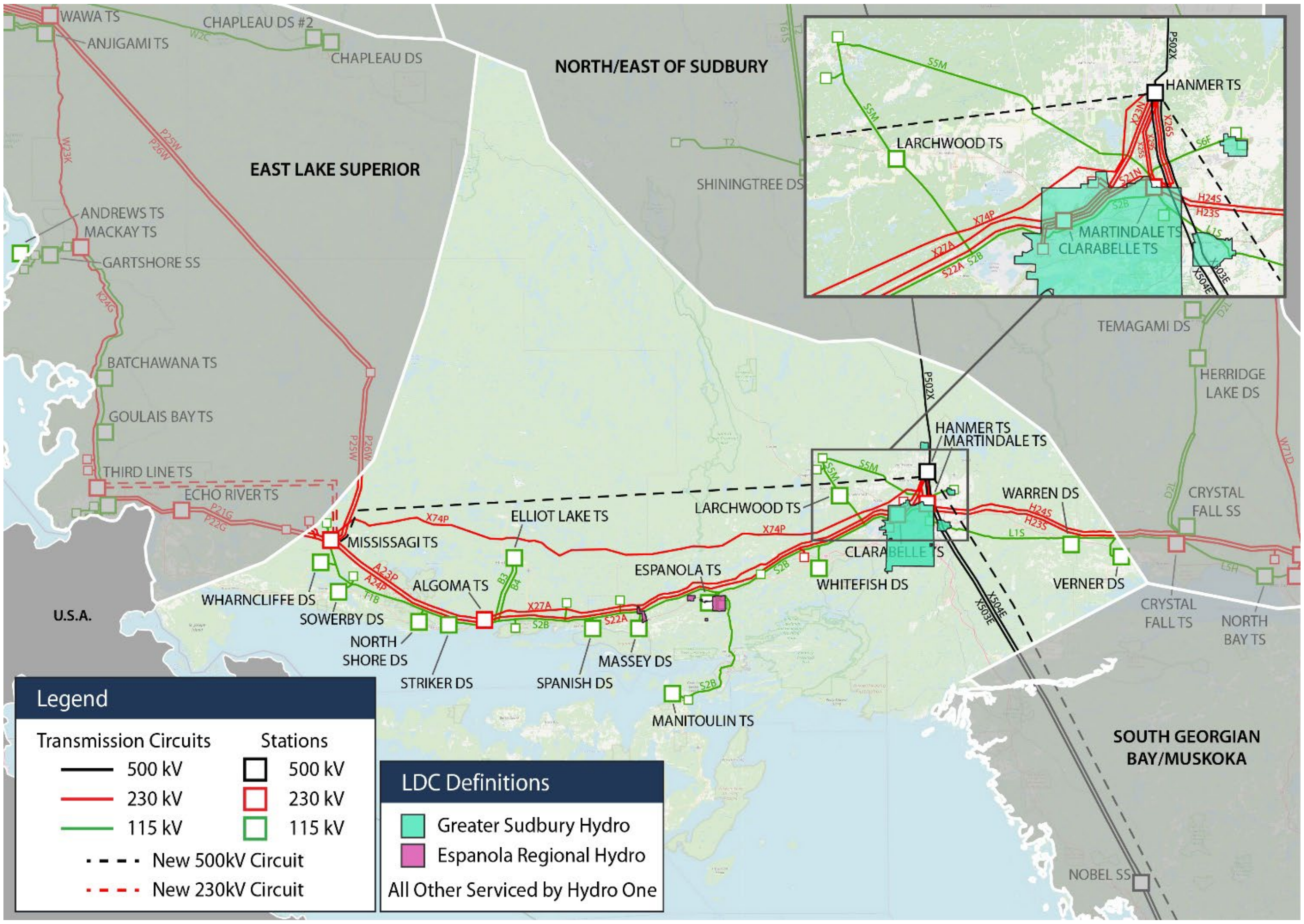
The Sudbury Algoma region is in northeastern Ontario and includes the area roughly bounded by the western shores of Lake Nipissing to the east, Wharncliffe to the west, Lake Superior/Manitoulin Island to the south.

Interested parties in this engagement initiative include but are not limited to:

Municipalities – the District of Algoma including the City of Elliot Lake, the Municipality of Huron Shores, the Towns of Blind River and Spanish, and the Township of the North Shore. The District of Manitoulin including Municipalities of Central Manitoulin and Gordon/Barrie Island, the Town of Northeastern Manitoulin & Islands and the Townships of Assiginack, Billings, Burpee and Mills, Cockburn Island and Tehkummah. The Municipality of West Nipissing in the District of Nipissing, the City of Greater Sudbury and the District of Sudbury including, the Municipalities of French River, Killarney, Markstay–Warren, St. Charles, the Town of Espanola, and the Townships of Baldwin, Nairn and Hyman, and Sables-Spanish Rivers.

Indigenous communities that may be potentially impacted or may have an interest based on treaty territory, traditional territory or traditional land uses including: Atikameksheng Anishnawbek First Nation, Aundeck Omni Kaning First Nation, Brunswick House First Nation, Dokis First Nation, Garden River First Nation, Henvey Inlet First Nation, M’Chigeeng First Nation, Mississauga First Nation, Nipissing First Nation, Sagamok Anishnawbek First Nation, Serpent River First Nation, Sheguiandah First Nation, Sheshegwaning First Nation, Thessalon First Nation, Whitefish River First Nation, Wiikwemkoong Unceded Territory.

Figure 1 | Sudbury Algoma Region Area Map



Routing of new circuits is for illustration purposes only, final routing to be determined by the transmitter.

Note that, for regional electricity planning purposes, the region is defined by electrical infrastructure rather than geography. The region is served by three LDCs who form part of the TWG: Greater Sudbury Hydro, North Bay Hydro, and Hydro One Distribution and one transmitter Hydro One Networks Inc.

Electrical supply to the region is provided primarily through the following:

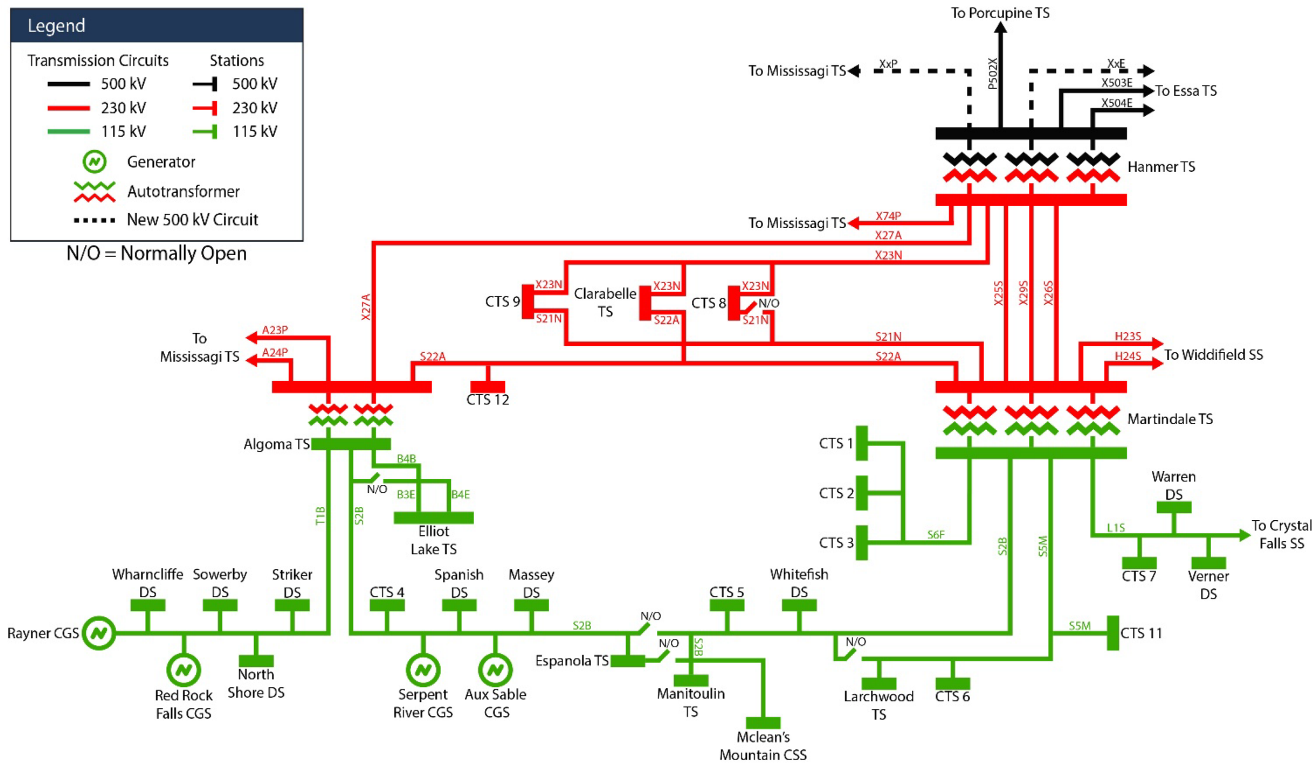
- 230 kV circuits and stations between Hanmer TS and Mississagi TS
- 230/115 kV autotransformers at Martindale TS and subsequent 115 kV circuits emanating from Martindale TS
- 230/115 kV autotransformers at Algoma TS and subsequent 115 kV circuits emanating from Algoma TS

The area also serves as the bulk transmission path connecting the East Lake Superior and Northwest Planning Regions to the remainder of the power system via 500/230 kV circuits in the area.

The area map of the region is shown in Figure 1 and the single line diagram of the electrical infrastructure in the region is shown in Figure 2.

In this region, the electrical load is comprised of industrial, commercial and residential users and is winter peaking. The region has a small amount ~100 MW of transmission connected hydroelectric generation, and a single transmission connected wind farm.

Figure 2 | Sudbury Algoma Region Transmission Single Line Diagram



3.1 Previous Regional Planning Cycle and Status Update

The previous cycle of regional planning for the Sudbury Algoma region was carried out during 2020. After reviewing the identified needs, the TWG decided that an IRRP was not required, and the needs could be addressed via a Regional Infrastructure Plan (RIP). The Sudbury Algoma RIP was published in December 2020. The IRRP used a 20-year demand forecast to identify near, mid and long-term needs and made recommendations for addressing these needs.

The recommendations made as part of the previous cycle of regional planning are summarized in Table 1 below. Note that these needs have evolved and recommendations were outlined in the Needs Assessment.

Table 1 | Recommendations from 2020 Sudbury Algoma RIP

Need	Recommendation	Lead Responsibility	Required By / Planned I/S date
Manitoulin TS Capacity Constraint	Change limiting CT ratio	HONI	2021
Under peak load conditions, the loss of two Martindale 230/115kV transformers may result in the overload of the third Martindale transformer	Martindale autotransformers T21/T23 Replacement project	HONI	2022
With either X25S or X26S is out of service, the loss of the companion circuit may result in voltage declines at Martindale 230kV and 115kV buses below acceptable limits set out in ORTAC	Unbundle X25S/X26S	HONI	2023
Elliot Lake TS end-of-life (EOL) power transformer replacement	Replace with new 115/44 kV 42 MVA units	HONI	2025
Algoma TS end-of-life (EOL) autotransformer replacement	Replace with new 230/115 kV 125 MVA units	HONI	2025
Clarabelle TS end-of-llife (EOL) power transformer replacement	Replace with new 230/44 kV 125 MVA units	HONI	2027
Martindale TS end-of-life (EOL) power transformer replacement	Replace with new 230/44 kV 125 MVA units	HONI	2028
Martindale TS supply capacity constraint	Maintain the status quo and reassess station supply needs during the next Regional Planning Cycle	HONI	2028

4. Needs Assessment Methodology

The first phase of the current regional planning cycle, the Hydro One-led Needs Assessment, was completed in October 2025.

This section briefly summarizes the needs identified in the Needs Assessment report. Please refer to the full Needs Assessment report for more details[1]. Section 5 specifies the planning approach and outlines the specific needs that will be in scope for subsequent regional planning stages.

4.1 Types of Electricity Needs

Based on the reference demand forecast (extreme weather, net demand), system capability, transmitters' identified end-of-life asset replacement plans, and the application of the IESO's Ontario Resource and Transmission Assessment Criteria[2], North American Electric Reliability Corporation's (NERC) Transmission System Planning Performance Requirements[3], and the Northeast Power Coordinating Council's (NPCC) Directory # 1 - Design and Operation of the Bulk Power System[4]. The Technical 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. 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.

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[1] The 2025 Sudbury Algoma Region Needs Assessment Report is available on Hydro One's website (Link).

[2] Ontario Resource and Transmission Assessment Criteria is available on the IESO's website (Link).

[3] Transmission System Planning Performance Requirements is available on NERC's website (Link).

[4] NPCC Directory #1 - Design and Operation of the Bulk Power System is available on NPCC's website (Link).

- **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 where like-for-like replacements have been established to be appropriate in earlier phases of the regional planning process.
- **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.

4.2 Needs Not Requiring Further Regional Coordination

The Sudbury Algoma Needs Assessment determined that the needs listed in Table 2 do not require further regional coordination.

Table 2 | Needs Identified in Needs Assessment Not Requiring Regional Coordination

Need	Need Description	Proposed Solution
Martindale TS 230/44 kV step-down transformers (T25 & T26)	Asset Renewal Need: T25 and T26 are approaching End of Life (EOL) based on their condition assessment.	Replacement of EOL assets with like-for-like.

4.3 Needs Requiring Further Regional Coordination

The latest Sudbury Algoma Needs Assessment identified several issues that need to be addressed during this cycle of regional planning. It based its assessment on the most up-to-date sustainment, a new 10-year demand forecast provided by the LDCs, and updated conservation and demand management (CDM) and distributed generation (DG) forecasts provided by the IESO. The needs identified in the report that require further regional planning coordination are summarized below.

Table 2 | Needs Identified in Needs Assessment Requiring Regional Coordination

Need	Need Description	Timing

Martindale TS 230/44 kV step-down transformers (T25 & T26)	The load exceeds the 10-day LTR of the step-down transformers, T25 and T26, based on winter demand forecast at the station by 2034.	Near Term
Martindale TS 230/115 kV Autotransformers (T21, T22, & T23)	With one autotransformer out-of-service and subsequent failure of another unit, the third autotransformer will exceed its winter 10-day LTR.	Near Term
Manitoulin TS 115 kV Voltage	The 115 kV bus at Manitoulin TS experiences low voltage under peak demand conditions at the station.	Near Term

4.3.1 Martindale TS 230/44 kV step-down transformers (T25 & T26)

T25 and T26 are 230/44 kV, 125 MVA step-down transformers supplying the DESN load at Martindale TS. For each season, the supply capacity of the DESN is determined by the winter and summer 10-day LTR of the most limiting transformer. The load at the DESN was expected to exceed its winter 10-day LTR of 164 MW by 2028 in the previous regional planning cycle. However, based on the latest load forecast developed in this Needs Assessment, the peak winter load is expected to exceed the winter 10-day LTR by 2034. The peak summer load at the station is lower and well within the summer 10-day LTR of the transformers.

Note, the capacity need of T25/T26 may be impacted by the asset renewal need of the same units if the 10-day LTR of the future units is greater than existing values.

4.3.2 Martindale TS 230/115 kV Autotransformers (T21, T22, & T23)

T21, T22 and T23 are 230/115 kV, 125 MVA autotransformers responsible for supplying the local 115 kV system which serves LDCs and industrial customers via 115 kV circuits. Under peak winter coincident load, the loss of two autotransformers will result in marginally overloading the third autotransformer above its 10-day LTR of 173 MW. This overload is expected to materialize in 2030 for transformer T23 with the least LTR (173 MW). The overload will be experienced on the other two units by 2034.

Similarly, autotransformer T22 reaches its 10-day LTR under a breaker fail contingency at Martindale TS which results in simultaneous loss of autotransformers T21 and T23. The 10-day LTR of T22 is slightly higher at 178 MW and the need is expected to materialize in 2034.

4.3.3 Voltage violations at Manitoulin TS

The 115 kV bus experiences low voltage under peak load conditions at Manitoulin TS. Under system conditions when Mclean Mountain wind farm is not generating and peak load conditions at Manitoulin TS, the 115 kV bus at the station is below the ORTAC limit of 113 kV. The ULTCs of the step-down transformers have a wide range and are able to maintain the 44 kV bus voltage within the ORTAC limits. This need was reaffirmed in the previous regional planning cycle. No mitigation was recommended since there was no material impact to customers connected on the 44 kV bus.

5. Regional Planning Approach

Needs identified through the Needs Assessment (NA) were reviewed during the Scoping Assessment to determine whether a Local Plan ("LP"), Regional Infrastructure Plan ("RIP"), or Integrated Regional Resource Plan ("IRRP") regional planning approach is most appropriate. An Integrated Regional Resource Plan is recommended for the Sudbury Algoma region. The Needs Assessment flagged several needs that may require further regional coordination and has potential impacts to the bulk system. Upon further consideration, this Scoping Assessment concurs with the Needs Assessment. Additionally, there is a high degree of stakeholder and community interest. The following sections outline the selection criteria, and the scope of the recommended IRRP.

5.1 Selection Criteria

The three potential planning outcomes are designed to carry out different functions and selection should be made based on the unique needs and circumstances in each area. The criteria used to select the regional planning approach within each sub-region are consistent with the principles laid out in the Planning Process Working Group Report to the Board[5], and are discussed in this document to ensure consistency and efficiency throughout the Scoping Assessment.

IRRPs are comprehensive undertakings that consider a wide range of potential solutions to determine the optimal mix of resources to meet the needs of an area for the next 20 years, including consideration of non-wires alternatives, conservation, generation, new technologies, and wires infrastructure. RIPs focus instead on identifying and assessing the specific wires alternatives and recommend the preferred wires solution for an area and are thus narrower in scope. LPs have the narrowest scope; only considering simple wires solutions that do not require further coordinated planning.

A LP process is recommended when needs:

- Are local in nature (only affecting one LDC or customer)
- Are limited investments of wires (transmission or distribution) solutions
- Do not require upstream transmission investments
- Do not require plan level community and/or stakeholder engagement and,
- Do not require other approvals such as a Leave to Construct application or Environmental Approval.

5 The Planning Process Working Group Report to the Board is available on the OEB's website (Link).

If it is determined that coordinated planning is required to address identified needs, either a RIP or an IRRP may be initiated. A series of criteria have been developed to assist in determining which planning approach is the most appropriate based on the identified needs. In general, an IRRP is initiated wherever:

- A non-wires measure has the potential to meet or significantly defer the needs identified by the transmitter during the Needs Assessment;
- Community or stakeholder engagement is required; or,
- The planning process or outcome has the potential to impact bulk system facilities

If it is determined that the only feasible measures involve new/upgraded transmission and/or distribution infrastructure, with no requirement for engagement or anticipated impact on bulk systems, a RIP will be selected instead.

Wires type transmission/distribution infrastructure solutions refer, but are not limited, to:

- Transmission lines
- Transformer/ switching stations
- Sectionalizing devices including breakers and switches
- Reactors or compensators
- Distribution system assets

Additional solutions, including conservation and demand management, generation, and other electricity initiatives can also play a significant role in addressing needs. Because these solutions are non-wires alternatives, they must be studied through an IRRP process.

5.2 Integrated Regional Resource Plan Scope of Work

Note that the primary purpose of an IRRP is to study needs that require coordination between transmitters, distribution companies, and the IESO. The IRRP will not study bulk system needs such as transfer capability on the 230 kV system such as those studied as part of the IESO's Need for Northeast Bulk System Reinforcement[6]. However, the load forecast developed during the IRRP will inform future bulk system studies. Additionally, the IRRP will not specifically address new customer transmission connection requests unless there is an opportunity to align with broader regional needs. While the IRRP welcomes information from project proponents to inform load forecasting and to ensure plans for regional infrastructure are adequate, individual customers connection requests may be better suited for a proponent driven Technical Feasibility Study.

The IRRP will focus on the needs described in Section 4.3.

[6] More information about the Need for Northeast Bulk System Reinforcement is available on the IESO's website (Link).

6. Conclusion and Next Steps

This Scoping Assessment concludes that a IRRP covering the entire region will be undertaken to address the needs as discussed in Section 4.3.

As further technical studies and community engagement are undertaken through the IRRP, new needs may come to light and be included in the scope of the IRRP. Additionally, the IRRP process is expected to be carried out in a manner that allows for continuous coordination of information with ongoing bulk system studies. The draft Terms of Reference for the Sudbury Algoma IRRP can be found in Appendix 2.

Furthermore, this Scoping Assessment concurs with the Needs Assessment recommendation to address the Martindale TS EOL need through local planning.

Appendix 1 – List of Acronyms

Acronym	Definition
API	Algoma Power Inc
CDM	Conservation and Demand Management
DG	Distributed Generation
EAF	Electric Arc Furnace
H1	Hydro One
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
LDC	Local Distribution Company
LTR	Limited Time Rating
MTS	Municipal Transformer Station
MVA	Mega Volt-Ampere
MW	Megawatt
NA	Needs Assessment
RAS	Remedial Action Scheme
TS	Transformer Station
TWG	Technical Working Group
ULTC	Under Load Tap Changer

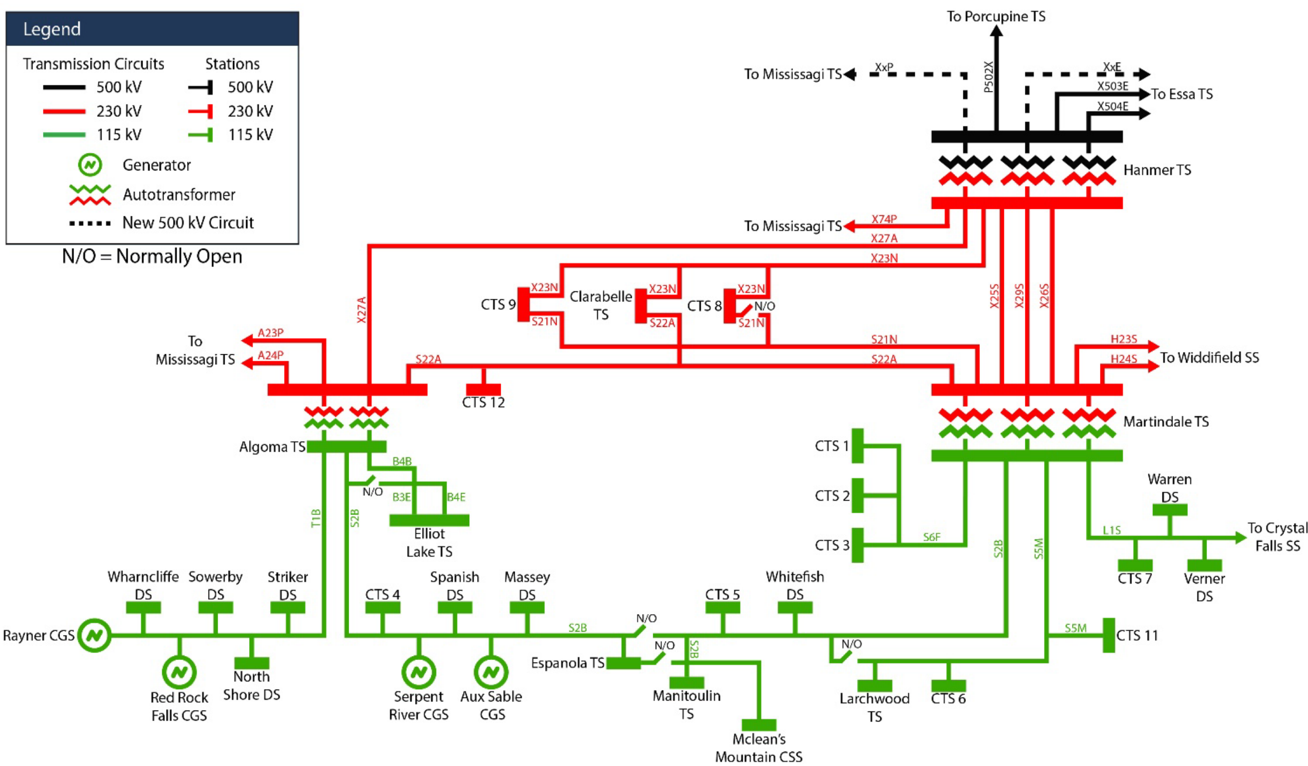
Appendix 2 – Sudbury Algoma IRRP Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for an Integrated Regional Resource Plan (IRRP) of the Sudbury Algoma region.

Based on the potential for demand growth within this region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended. The single line diagram is shown in Figure A-1.

Figure A-1 | Sudbury Algoma Region Transmission Single Line Diagram



The Sudbury Algoma region is in northeastern Ontario and includes the area roughly bounded by the western shores of Lake Nipissing to the east, Wharncliffe to the West, Lake Superior/Manitoulin Island to the south. For electricity planning purposes, the region is defined by electricity infrastructure boundaries, not municipal boundaries. It is one of four planning regions in Northeastern Ontario, adjacent to the North East of Sudbury region to the east and the East Lake Superior region to the West.

All transmission connected infrastructure bounded 230 kV circuits A23P and A24P to the West and H23S, H24S, and L1S to the East is included in this plan as shown in Figure 2.

In October 2025, Hydro One completed the Needs Assessment report for the Sudbury Algoma region. Several needs were identified, and a Scoping Assessment was subsequently commenced to determine the preferred planning approach.

2. Objectives

The Sudbury Algoma IRRP will assess the adequacy of electricity supply to customers in the region and will develop a set of recommended actions to maintain reliability of supply to the region over the next 20 years.

- Assess the adequacy of electricity supply to customers in the Sudbury Algoma region over the next 20 years;
- Determine whether there is a need to initiate development work or to fully commit infrastructure investments in this planning cycle;
- Identify and coordinate major asset renewal needs with regional needs, and develop a flexible, comprehensive, integrated electricity plan for Sudbury Algoma; and,
- Develop an implementation plan that is flexible to accommodate changes in key assumptions over time, while keeping options viable.

3. Scope

The IRRP will develop and recommend an integrated plan to meet the needs of the Sudbury Algoma region. The plan is a joint initiative led by the IESO and completed by the members of the TWG. The plan will consider the demand forecast for the region, the CDM, DER uptake, transmission, and distribution system capabilities, and align with relevant community plans, bulk system developments, and policy direction as applicable. The Sudbury Algoma IRRP aims to address the following needs, as identified in the 2025 Needs Assessment.

Table A-1 | Needs Requiring Further Regional Coordination

Need	Need Description	Timing
Martindale TS 230/44 kV step-down transformers (T25 & T26)	The load exceeds the 10-day LTR of the step-down transformers, T25 and T26, based on winter demand forecast at the station by 2034.	Near Term
Martindale TS 230/115 kV Autotransformers (T21, T22, & T23)	With one autotransformer out-of-service and subsequent failure of another unit, the third autotransformer will exceed its winter 10-day LTR.	Near Term
Manitoulin TS 115 kV Voltage	The 115 kV bus at Manitoulin TS experiences low voltage under peak demand conditions at the station.	Near Term

Other identified needs in the Needs Assessment not listed in the above table require monitoring or will proceed with Local Planning or Regional Infrastructure Planning as appropriate. Hydro One will keep the TWG informed on project development.

Based on the identified needs, the Sudbury Algoma IRRP process will consist of the following activities:

1. Develop an electricity demand forecast for the region. This may be comprised of a number of electricity demand scenarios that account for uncertain elements that can affect (e.g., raise or lower) the need for electricity in the region.
2. Confirm baseline technical assumptions including infrastructure ratings, system topology and relevant base cases for simulating the performance of the electric power system. Collect information on:
    a. Transformer, circuit continuous ratings, long-term and short-term emergency ratings
    b. Known reliability issues and load transfer capabilities
    c. Customer load breakdown by transformer station
    d. Historical and present CDM peak demand savings and installed/effective DER capacity, by transformer station
3. Perform assessments of the capacity, reliability, and security of the electric power system under each demand outlook scenario.
    a. Confirm and/or refine the needs listed earlier in this section using the demand outlook; establish the sensitivity of each need to different demand outlook scenarios

b. Identify additional infrastructure capacity needs and any additional load restoration needs; if new needs are discovered, determine the appropriate planning approach for addressing them

4. Identify options for addressing the needs, including, non-wires and wires alternatives. Where necessary, develop portfolios of solutions comprising a number of options that, when combined, can address a need or multiple needs.

   a. Collect information about the attributes of each option: cost, performance, timing, risk, etc

   b. Develop cost estimates for all screened-in options as a means of informing further evaluations of alternatives

   c. Seek cost-effective opportunities to manage growth, by identifying opportunities to reduce electricity demand

5. Evaluate options using criteria including but not limited to the areas of: technical feasibility and timing, economics, reliability performance, risk, environmental, regulatory, and social factors. Evaluation criteria will be informed through community engagement activities and reflect attributes deemed important to the community-at-large.

6. Develop recommendations for actions and document them in an implementation plan, to address needs in the near-term and medium-term.

7. Develop a long-term plan for the electricity system in the region to address the identified long-term needs, taking into account uncertainty inherent in long-term planning, local and provincial policy goals, commitments, and climate change action plans.

   a. Discuss possible ways the power system in the region could evolve to address potential long-term needs, support the achievement of local and provincial long-term policy goals and plans, and support the achievement of the long-term vision for the electricity sector

   b. During the development of the plan, seek community and stakeholder input to confirm the long-term vision, expected impacts on the electricity system, and inform the recommended actions through engagement

8. Complete an IRRP report documenting the near-term and medium-term needs, recommendations, and implementation actions; and long-term plan recommendations.

In order to carry out this scope of work, the Working Group will consider the data and assumptions outlined in section 4 below.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident peak demand information

    - Historical weather data (temperature, humidity, consecutive cooling/heating days, etc.) for the purpose of correcting demand for median/extreme weather conditions
    - Gross peak demand forecast scenarios by sub-region, TS, etc.
    - Identified potential future load customers
- Conservation and Demand Management
    - Conservation forecast for LDC customers, based on sub-region's share of current energy efficiency programs
    - Local Achievable Potential Studies
    - Potential for CDM at transmission-connected customers' facilities
- Local resources
    - Existing local generation, including distributed generation (DG), district energy, customer based generation, Non-Utility Generators and hydroelectric facilities as applicable
    - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals
- Relevant local plans, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans, Municipal Energy Plans and Climate Action Plans
    - Municipal Growth Plans
    - Indigenous Community Energy Plans
- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria (ORTAC)
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to customers
    - Other applicable requirements
- Existing system capability
    - Transmission line ratings as per transmitter records
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capability

  - Technical and operating characteristics of local generation
  - Bulk System considerations to be applied to the existing area network
- End-of-life asset considerations/sustainment plans
  - Transmission assets
  - Distribution assets
- Other considerations, as applicable

5. Technical Working Group

The IRRP Technical Working Group will consist of planning representatives from the following organizations:

- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. Transmission (HONI Tx)
- Hydro One Distribution (HONI Dx)
- Greater Sudbury Hydro
- North Bay Hydro

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

6. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. As such, the IESO, in consultation with the Technical Working Group, is committed to conducting engagement in accordance with IESO Engagement Principles throughout the development of the IRRP.

The first step in engagement will consist of the development of an engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 4 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

7. Activities, Timelines and Primary Accountabilities

Table A-2 | IRRP Timelines & Activities

Activity	Lead	Deliverable	Timeline
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	Q1 2026
2. Develop planning forecast scenarios for the Sudbury Algoma region		Planning forecast scenarios	Q1-Q2 2026
a. Establish historical coincident peak demand information	IESO		
b. Establish historical weather correction, median and extreme conditions	IESO		
c. Establish gross peak demand forecast	LDCs		
d. Establish existing, committed, and potential DG	LDCs		
e. Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		
3. Confirm load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system needs and identifying options for addressing these needs	LDCs/ Transmission	Load transfer capabilities under normal and emergency conditions	Q2 - Q3 2026
4. Provide and review relevant community plans, if applicable	LDCs, Indigenous communities, and IESO	Relevant community plans	Q1 2026

Activity	Lead	Deliverable	Timeline
5. Complete system studies to identify needs over a 20-year time horizon Develop base case(s) for simulations Apply reliability criteria as defined in ORTAC and other applicable criteria to demand forecast scenarios Confirm and refine the needs and timing/load levels	IESO	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q2 – Q3 2026
6. Develop options and alternatives		Flexible planning options for forecast scenarios	Q3 2026-Q1 2027
a. Conduct a screening to identify which wire and non-wires options warrant further analysis	IESO		
b. Produce hourly forecasts for each transformer station to enable detailed needs characterization and support options development	IESO		
c. Develop energy efficiency options	IESO and LDCs		
d. Develop local generation/demand management options	IESO and LDCs		
e. Develop transmission and distribution alternatives (i.e. alignment with EOL sustainment plans, load transfers)	IESO and transmission		
f. Develop portfolios of integrated alternatives	TWG		
g. Technical comparison and evaluation	TWG		

Activity	Lead	Deliverable	Timeline
7. Plan and undertake community and stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Metis Nations of Ontario	Ongoing as required IRRP engagement to be launched in Q4 2025
a. Early engagement with local communities and First Nation communities within the study area or who may have in interest in the study area	TWG		
b. Develop communications materials	TWG		
c. Undertake community and stakeholder engagement	TWG		
d. Summarize input and incorporate feedback	TWG		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q2 2027
9. Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties	IESO	IRRP report	July 2027

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