East Lake Superior Integrated Regional Resource Plan

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Table of Contents

List of Figures

List of Tables

List of Appendices

List of Abbreviations

BESS	Battery Energy Storage System
CDM	Conservation and Demand Management
DG	Distributed Generation
DR	Demand Response
DS	Distribution Station
EAF	Electric Arc Furnace
ELS	East Lake Superior
eDSM	Electricity Demand Side Management
FIT	Feed-in-Tariff
HONI	Hydro One Networks Inc.
HOSSM	Hydro One Sault Ste. Marie
IBR	Inverter-Based Resource
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LSP	Lake Superior Power
LTR	Limited Time Rating
MSR	Municipal Support Resolution
MSU	Mobile Substation Unit
MVA	Megavolt ampere
MVAr	Megavolt ampere reactive
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council

NWA	Non-Wires Alternative
OEB	Ontario Energy Board
ONAF	Oil Natural Air Forced
ONAN	Oil Natural Air Natural
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PLL	Planned Loading Limit
PPWG	Planning Process Working Group
RAS	Remedial Action Scheme
RIP	Regional Infrastructure Plan
TG	Transmission-connected Generation
TS	Transmission Station
TWG	Technical Working Group

Executive Summary

Regional planning is a collaborative process that evaluates a range of supply resource and transmission options to ensure the electricity system remains reliable, affordable, and capable of supporting future growth. Developed with input from municipalities, Indigenous communities, utilities, and other regional stakeholders, these plans reflect the unique characteristics and needs of each planning region. The East Lake Superior region — encompassing the City of Sault Ste. Marie, the Township of Chapleau, and surrounding municipalities and districts extending from the Town of Dubreuilville in the north to the Town of Bruce Mines in the south — has a distinct electricity profile shaped largely by energy-intensive industrial activity and electrification initiatives.

Future electricity needs in the East Lake Superior region are expected to be driven primarily by industrial development and electrification initiatives rather than broad-based growth across the region. As a result, electricity system needs are localized and tied to specific areas of the system rather than widespread capacity constraints. With the inclusion of major system developments, including the 2022 Northeast Bulk Reinforcement Plan, no new medium- or long-term regional electricity needs are identified over the current planning horizon. However, a limited number of localized reliability and supply capacity needs are expected to emerge in the near term and are addressed through the recommendations in this plan.

A range of potential solutions was evaluated, including transmission and distribution reinforcements, local generation, demand-side resources, operational measures, and non-wires alternatives. The recommended approaches represent the most cost-effective and practical means of addressing identified system needs, while maintaining system reliability and ensuring infrastructure improvements are made at the appropriate time.

Implementation-Ready Actions

The following actions are recommended as near-term investments to maintain reliability and enable growth in the East Lake Superior region. Evaluated across a range of planning scenarios, these actions are considered implementation-ready and should proceed through development and implementation.

Chapleau Area – Supply Capacity
To maintain reliable electricity supply in the Chapleau area and support forecast growth, the IESO and the Technical Working Group (TWG) recommend a localized voltage support solution to address limitations on the existing supply path. Demand-side resources, including electricity Demand Side Management (eDSM), are also recommended to provide incremental support and help make the best use of existing system capacity at the lowest cost.

Chapleau DS – Station Capacity Monitoring
The TWG will continue to monitor load growth and system conditions at Chapleau Distribution Station (DS) and Chapleau DS2 to ensure the electricity system remains well-positioned to accommodate future growth. While no station capacity need has been identified under current planning assumptions, demand under higher-growth scenarios may approach available station capacity over

the longer term. Ongoing monitoring will help identify any emerging needs early and provide sufficient lead time to develop and implement appropriate solutions.

Algoma Area – Supply Reliability

To maintain reliable electricity service in the Algoma area, which is supplied by three transmission lines, a staged approach consisting of interim control actions, followed by enhancements to the existing Remedial Action Scheme (RAS)[1] is recommended. This approach addresses a contingency-driven limitation by improving the selectivity of load rejection over time, restoring compliance with planning criteria while striking a balance between operational measures and the timing of more complex and capital-intensive transmission reinforcements.

Sault Ste. Marie Area – Supply Reliability

Pursue the development and implementation of a cost-effective supply resource capable of meeting the identified reliability need. The IESO will advance this recommendation through appropriate procurement mechanisms, consistent with the performance requirements of the need. The capability of the resource must match the characteristics of the need, requiring a resource that is dispatchable when needed and capable of sustained operation for the duration of a contingency condition. This performance-based approach preserves flexibility with respect to the specific technology while providing a targeted and cost-effective solution. In addition to addressing reliability needs, such a resource can also provide broader system value through energy and capacity contributions under normal operating conditions.

Future Considerations and Optionality

In addition to implementation-ready actions, the IRRP identifies longer-term infrastructure options that could be considered if demand growth, system conditions, or supply resource availability evolve differently than currently expected. While these options are not required at this time, they inform future planning and system readiness as conditions evolve, preserving optionality and protect against overbuilding.

One such option is the potential addition of a third autotransformer at Third Line Transformer Station which is associated with the Sault Ste. Marie 115 kV system interface reliability need. While not required at this time, this investment would increase system redundancy and provide a longer-term infrastructure option should demand growth increase reliability requirements in the future.

Future infrastructure options will continue to be assessed as part of ongoing TWG reviews, considering updated demand forecasts, system performance, and the availability of supply resources.

During the preparation of this report, Hydro One Distribution identified a potential project at Chapleau Distribution Station (DS) involving the addition of a new transformer. This project is currently in the early scoping phase, with a tentative in-service timeframe of approximately 2029, and remains subject to further technical assessment, siting considerations, and internal approvals. This emerging development reinforces the need for ongoing monitoring of station capacity conditions identified in this plan.

[1] A Remedial Action Scheme or RAS is a scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and MVar), tripping load, or reconfiguring the system.

As this information became available late in the study process, its potential impact on system capacity and voltage performance in the Chapleau area has not been assessed. While it may influence future system needs, the recommended plan outlined in this IRRP remains appropriate based on available information. The TWG will continue to monitor this development and assess its implications as part of the Regional Infrastructure Plan (RIP) phase or future regional planning cycles.

In addition, the ability to site new supply resources in the region is currently constrained by system conditions, including limits on inverter-based generation and congestion on key transmission elements. These constraints will be monitored and may be addressed through future planning as system conditions evolve. Where new strategic supply resources are recommended in plans, the IESO will further develop linkages to ensure procurement signals are clear to address system needs.

Implementation and Monitoring

Implementation of the recommended actions will proceed through established mechanisms, including Regional Infrastructure Plans and procurement processes, supported by continued co-ordination through the TWG.

System conditions, demand growth, and the performance of implemented solutions will be actively reviewed. Where conditions materially change, additional analysis and planning will be undertaken through future regional planning cycles to ensure continued reliability of the electricity system in the ELS region.

Conclusion

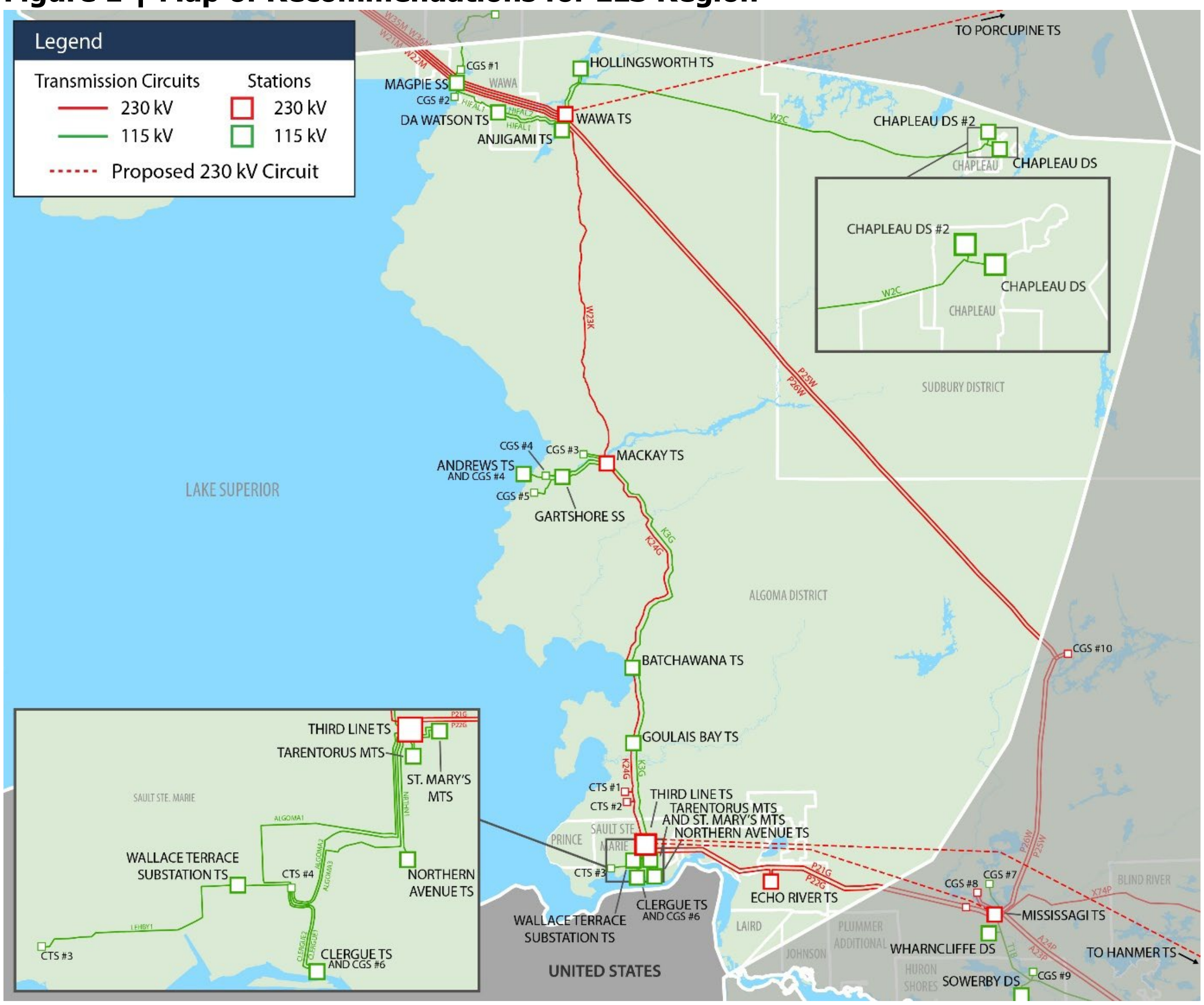
Overall, this IRRP provides a clear, proportionate, and flexible plan to address the identified electricity system needs of the ELS region. The recommended actions are designed to maintain near-term system reliability while enabling further customer and industry connections. The plan also preserves optionality to respond to future changes in demand, system conditions, and resource availability.

Table 1 | Implementation-Ready Actions

Action	Reinforcement Type	Needs Addressed	Implementation	Expected In-Service
Chapleau reactive power support	Transmission-side static reactive power support, with demand side measures serving as short-term supplement	Addresses voltage-limited supply capacity in the Chapleau area	Hydro One (reactive support); IESO (eDSM)	Near-term
Address Algoma 115 kV interface supply capacity need	Enhance existing RAS to support more flexible control actions; load rejection exemption framework	Mitigates contingency-driven thermal limitation at the Algoma 115 kV interface	Hydro One	Near-term

Action	Reinforcement Type	Needs Addressed	Implementation	Expected In-Service
Address Sault Ste. Marie 115 kV interface supply capacity need	Performance based supply solution with demand side measures	Addresses voltage instability limitations in the Sault Ste. Marie 115 kV area	IESO (lead); TWG support	Near- to mid-term
ELS region monitoring	Planning/monitoring	Preserves long-term flexibility and informs future infrastructure-based solutions	TWG	Ongoing

Figure 1 | Map of Recommendations for ELS Region



1. Introduction

1.1 Overview of Regional Electricity Planning

Regional electricity planning in Ontario is a structured process used to identify and address electricity needs at a regional level in a co-ordinated, reliable, and cost-effective manner. The regional planning process was formalized by the Ontario Energy Board (OEB) in 2013 and is carried out on a five-year planning cycle for each of Ontario's 21 planning regions. The process is undertaken collaboratively by the Independent Electricity System Operator (IESO), transmitters, and local distribution companies (LDCs) through a Technical Working Group (TWG). The IESO leads the Scoping Assessment and Integrated Regional Resource Plan (IRRP) stages of the process.

The regional planning process includes four key phases:

1. Needs Assessment (Led by the Transmitter)

The Needs Assessment is the first phase of regional planning and is led by the incumbent transmitter for the region. It evaluates the adequacy of the existing electricity system under forecast demand conditions to determine whether there are any emerging reliability or capacity concerns. The assessment applies applicable planning criteria and identifies whether electricity needs exist that may require further regional co-ordination. If no needs are identified, no further regional planning activities are required at that time.

2. Scoping Assessment (Led by the IESO)

Where needs are identified, the IESO leads a Scoping Assessment to determine the appropriate planning approach to address them. The Scoping Assessment confirms the nature and extent of the identified needs and recommends whether they should be addressed through an IRRP, a RIP, or other planning mechanisms. The Scoping Assessment also defines the geographic scope, time horizon, and level of co-ordination required.

3. Integrated Regional Resource Plan (Led by the IESO)

The IRRP is led by the IESO and developed in collaboration with transmitters, LDCs, and other members of the TWG. The IRRP assesses regional electricity needs over the near-, medium-, and long-term and evaluates a range of options to address those needs. Options considered may include transmission and distribution solutions, electricity demand-side management (eDSM), non-wires alternatives (NWAs), and generation resources. The IRRP culminates in recommended actions to address near- and medium-term needs and outlines monitoring or trigger-based approaches for longer-term needs.

4. Regional Infrastructure Plan (Led by the Transmitter)

Where the IRRP identifies transmission or distribution infrastructure solutions as recommended actions, these are carried forward into the RIP stage. The RIP is led by the transmitter and provides greater implementation detail, including preferred solution selection, siting considerations, technical design, cost estimates, and engagement activities. The RIP supports regulatory approval and eventual construction of recommended infrastructure projects.

This IRRP represents the second cycle of regional planning for the ELS region.

1.2 Purpose of this IRRP

This IRRP assesses the reliability and adequacy of the electricity system in the ELS region over a 20-year planning horizon (from 2025 to 2044). The goal is to identify near-, medium-, and long-term needs, propose suitable options, and recommend actions to maintain a reliable and cost-effective electricity system while considering:

- projected electricity demand growth;
- infrastructure condition and capacity;
- opportunities for energy efficiency and NWAs; and
- emerging trends (e.g., electrification, distributed energy resources).

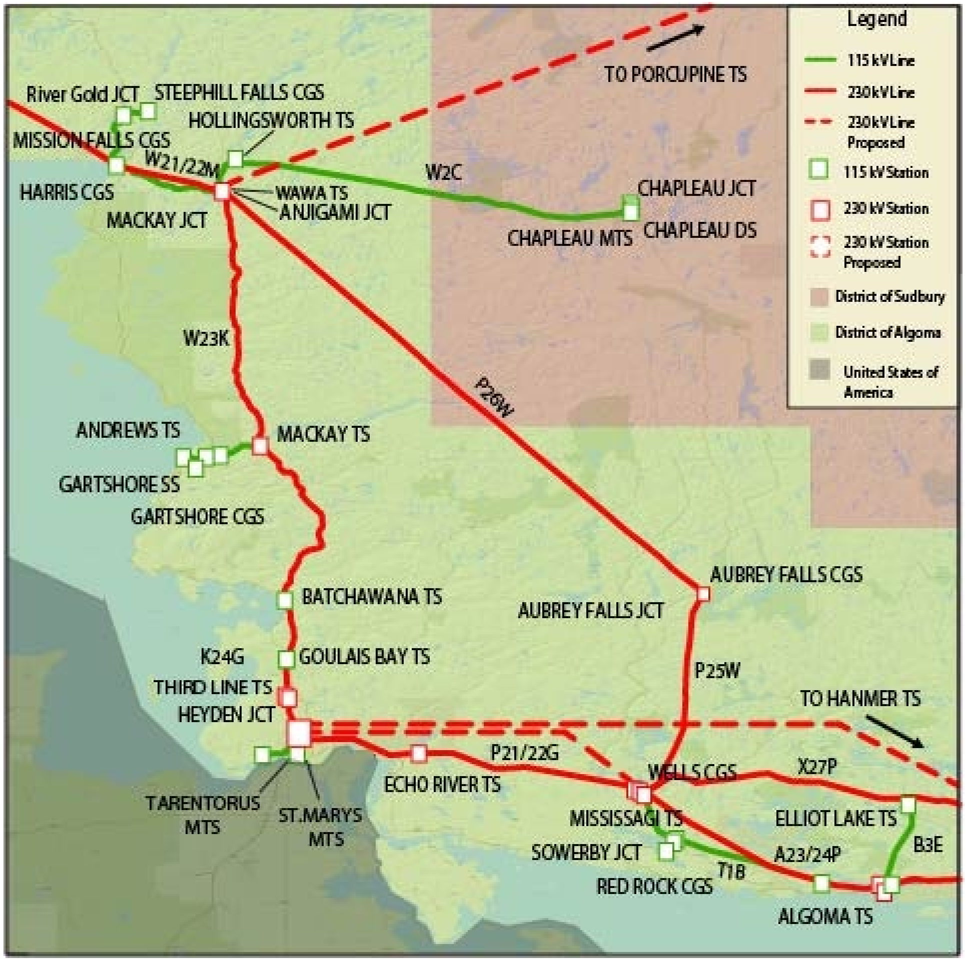
The outcome of this IRRP includes recommended infrastructure solutions, some of which will be reviewed further in the forthcoming RIP.

1.3 Description of the Area

The ELS region encompasses the City of Sault Ste. Marie, the Township of Chapleau, and surrounding municipalities and districts extending from the Town of Dubreuilville in the north to the Town of Bruce Mines in the south. Geographically, the region is surrounded by Lake Superior to the west, Highway 129 to the east, Highway 101 to the north, and St. Mary's River and St. Joseph Channel to the south, defined not only by physical geography but also by shared electricity infrastructure. The region includes the following:

- Municipalities and Townships: Town of Bruce Mines, Township of Chapleau, Hilton Township, The Municipality of Huron Shores, Township of Jocelyn, Township of Johnson, Laird Township, Township of Macdonald, Meredith & Aberdeen Additional, Township of Plummer Additional, Prince Township, City of Sault Ste. Marie, Township of St. Joseph, Tarbutt Township & Tarbutt Additional, Township of Dubreuilville, and Municipality of Wawa.
- Indigenous Communities: Batchewana First Nation, Brunswick House First Nation, Chapleau Cree First Nation, Chapleau Ojibwe First Nation, Garden River First Nation, Michipicoten First Nation, Missanabie Cree First Nation, Mississauga First Nation, Serpent River First Nation, Thessalon First Nation, Métis Nation of Ontario, Bar River Métis, and Red Sky Métis Independent Nation.
- LDCs Operating in the Region: Algoma Power Inc., Hydro One Distribution and PUC Distribution Inc.
- Lead Transmitter: Hydro One Networks Inc. Transmission (HONI), Hydro One Sault Ste. Marie (HOSSM), and PUC Transmission Inc.

Figure 2 | Overview Map of the ELS Region[3]



1.4 Demand and Infrastructure Overview

The electricity demand in the region is expected to follow a winter-peaking pattern, driven by industrial development. Average annual growth is projected at 4.8% based on winter reference scenario and 5.7% based on summer reference scenario.

Electricity is supplied through a combination of:

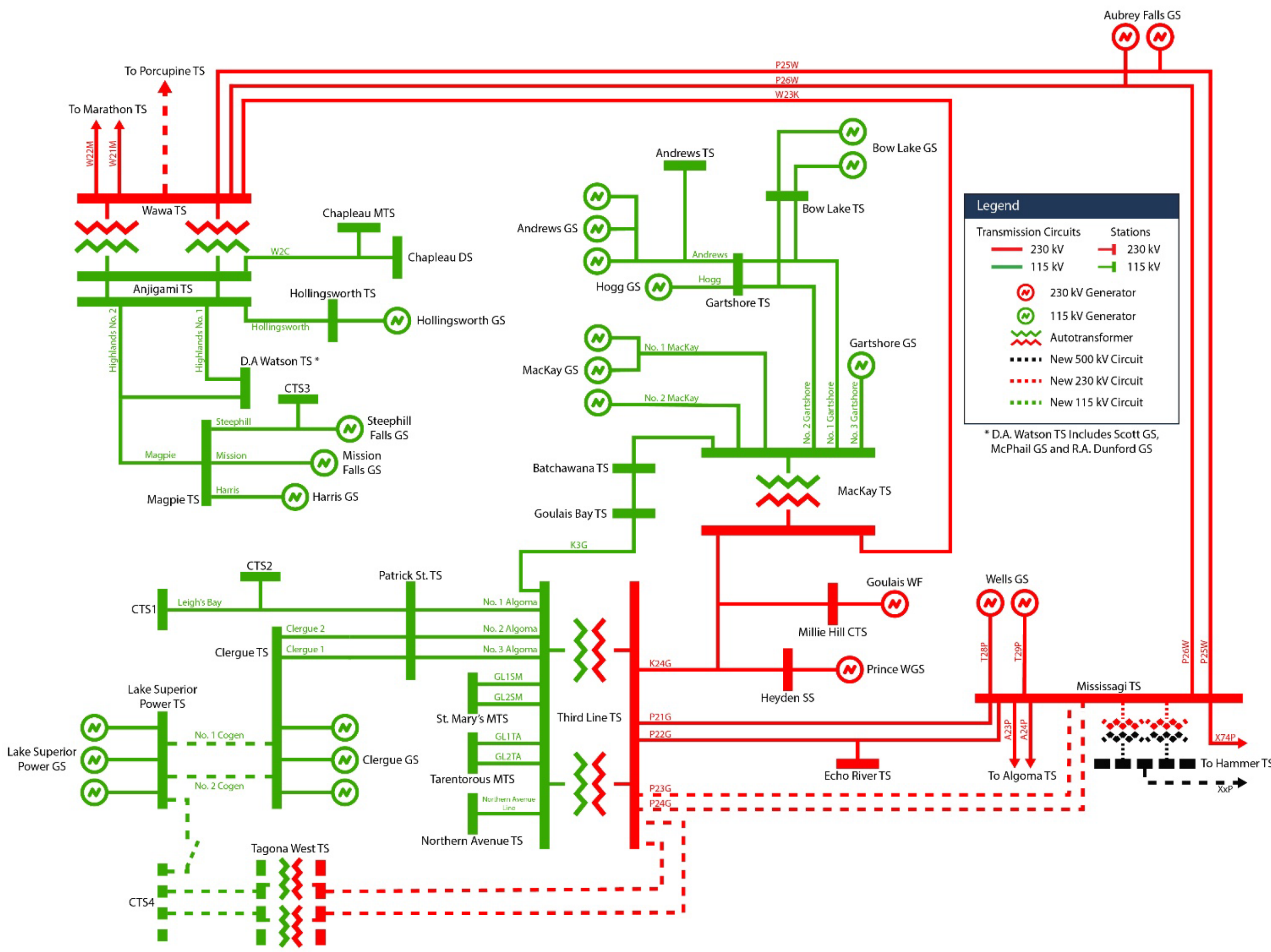
- 230 kV and 115 kV transmission infrastructure, with electrical supply provided mainly through 230/115 kV autotransformers at Third Line Transformer Station (TS), Mackay TS, and Wawa TS, as shown in Figure 2.
- Local generation, including more than 1,200 MW of hydroelectric, wind, solar, and thermal generation.

[3] IRRP regions are defined by electricity infrastructure; geographical boundaries are approximate.

Over the planning horizon, potential demand growth from industrial development, mining activity, and electrification initiatives may require the evaluation of supply options and infrastructure upgrades.

Figure 3 is a single line diagram showing major electrical infrastructure in the region.

Figure 3 | Electricity Infrastructure in the ELS Region



1.5 Organization of this IRRP

This IRRP outlines the ELS TWG's plan to continue to maintain a reliable, affordable, sustainable electricity supply to support the region. This IRRP is structured as follows:

Section 2 — Summary of the recommended plan and near-/medium-term actions

Describes the IRRP within Ontario's regional electricity planning framework and outlines how it addresses identified electricity needs through co-ordinated planning.

Section 3 Planning process and methodology

Explains the regional planning process and summarizes how the IRRP was developed, including roles, responsibilities, and key planning steps.

Section 4 — Background and context for study scope

Provides context for electricity planning in the ELS region and defines the study scope, including system assets, interfaces, and planning assumptions.

Section 5 — Electricity demand forecast

Presents the development of the regional electricity demand forecast, including historical demand, forecast methodology, and planning assumptions.

Section 6 — Identified needs and system limitations

Identifies and categorizes electricity system needs based on forecast demand and system capability, including station, supply, refurbishment, and reliability needs.

Section 7 — Options considered and recommended solutions

Evaluates options to address identified needs and presents recommended actions based on technical, economic, and reliability considerations.

Section 8 — Community and stakeholder engagement

Summarizes engagement activities undertaken to inform stakeholders and incorporate local input into the regional planning process.

Section 9 — Conclusion and next steps

Summarizes the IRRP's findings and recommendations and outlines next steps for implementation, monitoring, and future planning cycles.

Appendices provide additional detail including technical studies, demand assumptions, and supporting engagement documentation.

2. The Integrated Regional Resource Plan

2.1 Overview of the Plan

This section presents the recommended IRRP for addressing electricity needs in the ELS region over a 20-year planning horizon. The plan includes a combination of near-term actions, future optionality, and ongoing monitoring activities to address emerging needs.

The recommendations are informed by a detailed needs assessment based on system capability, forecast demand, and applicable reliability criteria. The plan reflects input from the regional TWG, local stakeholders, Indigenous communities, and the IESO's planning assessments.

Electricity needs and corresponding solutions are grouped based on geography (local, regional, or bulk system-level), timing (near-, mid-, or long-term), and need type (e.g., station capacity, supply capacity, asset condition, load security, load restoration). In this IRRP, the focus is on a limited number of localized near-term supply capacity needs, with ongoing monitoring and future optionality to respond to changing system conditions. Where relevant, needs are linked to bulk system planning efforts to support co-ordinated and efficient infrastructure development.

2.2 Needs, Solutions and Timeframe

Types of Needs

This IRRP refers to a number of different need types and corresponding solutions. These needs and their solutions include:

- Station Capacity: Load transfers, station upgrades, or new transformer stations where required. In this IRRP, no near-term station capacity need is identified.
- Supply Capacity: Transmission circuit upgrades, reactive support, controlled load interruption, remedial action schemes, or non-wires solutions, depending on the nature of the need. In this IRRP, the identified near-term needs are primarily supply capacity needs.
- End-of-Life: Like-for-like or right-sized replacement of aging infrastructure, where relevant.
- Load Security: Transmission reinforcements, reconfiguration, or other measures to reduce the amount of load interrupted following major outages.
- Load Restoration: Mobile transformers, switching arrangements, or operational measures to improve restoration following outages.

Refer to Section 6.1 for further technical details.

Classification of Needs

Three main types of needs are discussed:

- Local Needs: Specific to one facility, interface, or community.
- Regional Needs: Affect multiple customers, communities, or areas within the region.

- Bulk System Needs: Linked to upstream transmission capability or broader provincial supply and transmission considerations.

Planning Timeframes

This IRRP covers three planning timeframes:

- Near-Term Plan: 0–5 years
- Mid-Term Plan: 6–10 years
- Long-Term Plan: 11–20 years

In this IRRP, the earliest identified needs are expected to emerge in the near term, beginning around 2028. No new distinct medium- or long-term regional electricity needs are identified over the planning horizon. Needs influenced by bulk system developments are co-ordinated accordingly.

2.3 Needs and Recommendations

Based on this analysis, the ELS IRRP recommends a broad range of solutions to address identified needs. Recommendations include:

- "Implementation-ready" or near-term actions to develop infrastructure such as new and expanded transmission stations to enable reliable supply for forecast demand across the region while improving system operability to a level comparable with the rest of Ontario, and
- "Future-consideration" or long-term actions, identified to preserve longer-term optionality and serve as a backstop if near-term supply resource solutions do not materialize or if system conditions change, including higher-than-expected demand growth. These actions would be monitored and revisited through future planning cycles as conditions evolve.

Table 2 summarizes system needs and corresponding recommendations.

Table 2 | Implementation-Ready Actions for the ELS Region

Need	Recommendation	Lead Responsibility	Required By
Voltage-limited supply capacity in the Chapleau area	Implement transmission-side reactive power support, with demand-side measures (eDSM) as interim support	Hydro One (reactive support); IESO (eDSM)	Near-term
Algoma 115 kV interface supply capacity	Enhance existing RAS to support more flexible control actions; load rejection exemption framework	Hydro One	Near-term

Need	Recommendation	Lead Responsibility	Required By
Sault Ste. Marie 115 kV interface supply capacity	Develop and procure a performance-based supply solution with demand side measures	IESO (lead), TWG support	Near to mid-term
ELS region system monitoring and long-term planning	Planning and monitoring to preserve long-term flexibility and inform future infrastructure-based solutions	TWG	Ongoing

Table 3 | Future-Ready Actions for the ELS Region

Need	Recommendation	Lead Responsibility	Required By
Sault Ste. Marie 115 kV interface supply capacity	New 230/115 kV autotransformer at Third Line TS	Hydro One	To be determined

2.3.1 Chapleau Area

A supply capacity need is expected to emerge in the Chapleau area, including Chapleau Distribution Station (DS) and Chapleau DS2, which are supplied by the 115 kV W2C transmission path. This need is driven by voltage limitations under peak conditions following the retirement of local generation, which reduce the load meeting capability of the W2C path.

The recommended approach is to implement reactive support to improve voltages in the area. This would directly address the underlying voltage limitation and replace the voltage support previously provided by local generation.

Demand-side measures and distributed energy resources, including additional eDSM, were also assessed and may provide modest short-term relief during the initial years following need onset. However, consistent with regional planning assumptions regarding achievable contribution levels, these resources are considered supplementary measures only and are not sufficient to independently address the identified supply capacity need.

In addition to the needs and solutions identified above, Hydro One Distribution identified a potential project during the preparation of this report involving the addition of a new transformer at Chapleau DS to accommodate incremental load from an existing customer. This project is currently in the early scoping phase, with a tentative in-service timeframe of approximately 2029. At present, no footprint exists within the existing station, and expansion options, including development on adjacent lands, are being explored.

Due to the timing of this information and its preliminary nature, the TWG has not assessed its impact on system capacity or the identified voltage limitations in the Chapleau area. As a result, the recommended plan for the Chapleau area remains unchanged. However, this development may influence future system needs, including the timing or scope of reinforcements. The TWG recommends that this project be monitored and further evaluated as part of the RIP phase or future regional planning cycles once additional information becomes available.

2.3.2 Algoma 115 kV Interface

The Algoma 115 kV interface, consisting of the Algoma No. 1, No. 2, and No. 3 transmission lines supplying radially connected industrial load, is subject to a contingency-driven thermal limitation. Under a recognized breaker-failure or sequential outage scenario, loading on the remaining in-service circuit exceeds applicable Ontario Resource and Transmission Assessment Criteria (ORTAC) and requires mitigation.

To address this limitation, enhancement of the existing RAS has been identified as the preferred long-term solution. The enhancement will improve the selectivity of the scheme by refining tripping actions to target individual load breakers, rather than disconnecting entire circuits. This more granular control will reduce the amount of load rejected under contingency conditions while ensuring that post-contingency loadings remain within ORTAC criteria.

Given the industrial nature of the load served and the low-frequency, contingency-driven nature of the limitation, customer agreements for controlled load interruption will be maintained as an interim measure until the RAS is implemented and placed in service. This approach provides a proportionate and practical means of maintaining compliance with planning criteria while avoiding significant transmission reinforcements under relatively stable demand conditions.

2.3.3 Sault Ste. Marie 115 kV System Interface

A contingency involving the loss of both Third Line autotransformers results in voltage instability on the Sault Ste. Marie 115 kV system. Under this condition, the remaining 115 kV network is unable to reliably serve load, resulting in a supply capacity limitation.

The recommended action is to pursue a cost-effective supply solution with performance characteristics aligned with the identified reliability risk. The capability of the resource must match the characteristics of the need, requiring a resource that is dispatchable when needed after a contingency, and capable of sustained operation for the duration of the contingency condition. This performance-based framing preserves flexibility with respect to the specific technology or acquisition approach, supports transparency with communities, and allows the need to be addressed, subject to demonstrated deliverability and applicable municipal and provincial siting requirements, and all other requirements and contractual obligations of any applicable procurement mechanism. No new infrastructure is required to maintain near-term reliability following completion of planned developments, allowing time to pursue this approach. At the same time, the addition of a third autotransformer at Third Line remains a future consideration and backstop option if a suitable supply solution does not materialize or if demand grows beyond current expectations.

2.4 Ongoing Initiatives

This IRRP is supported by ongoing transmission and station projects outside the scope of the recommendations in this plan. These initiatives form part of the broader planning context for the ELS region and include:

The 2022 Northeast Bulk Reinforcement Plan, which significantly strengthens bulk supply into northeast Ontario through new 230 kV and 500 kV infrastructure to support supply to the ELS region and more broadly, into northwestern Ontario, including:

- The Hanmer TS to Mississagi TS 500 kV transmission line project;
- The Mississagi TS to Third Line TS 230 kV transmission line project;
- The Porcupine TS to Wawa TS 230 kV transmission line project; and

Ongoing asset replacement and refurbishment projects across the region, including autotransformer and station upgrades at Third Line TS, Wawa TS, Batchawana TS, and Goulais Bay TS, as well as transmission line refurbishment at Sault #3 (K3G).

2.5 Regional Context and Key Planning Assumptions

Electricity demand within the ELS region is characterized by large, project-driven load additions, primarily associated with industrial activity, resource development, and electrification initiatives. Unlike regions experiencing steady population-driven growth, demand in ELS tends to increase through distinct step-changes occurring over relatively short lead times. As a result, many identified electricity system needs are driven by system configuration, contingency performance, and planning-criteria requirements, rather than pervasive growth across the network.

This IRRP reflects the implementation or advancement of several major system initiatives that establish the reference system for this planning cycle, including:

- The Northeast Bulk Reinforcement, which significantly strengthens bulk supply into northeast Ontario through new 230 kV and 500 kV transmission facilities and additional transformation capacity.
- The staged implementation of the Algoma Steel Electric Arc Furnace (EAF) project, culminating in full reliance on transmission-supplied load following completion of planned development phases.
- Ongoing asset replacement and refurbishment projects across the region, including autotransformer and station upgrades at Third Line TS, Wawa TS, Sault #3 circuit (K3G), Batchawana TS, and Goulais Bay TS.
- New and expanding industrial and mining-related load connections, incorporated into the regional demand forecast.

Collectively, these developments materially reinforce the ELS transmission system and address or defer previously identified longer-term constraints. With the inclusion of the Northeast Bulk Reinforcement Plan and planned asset replacements, no immediate electricity system needs are identified at the beginning of the study period, and no new or distinct medium- or long-term regional electricity system needs were identified over the planning horizon.

Accordingly, this IRRP focuses on a limited number of anticipated near-term supply capacity needs, with the earliest needs emerging later in the study period, beginning around 2028.

3. Development of the Plan

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is conducted through the regional planning process, which was formalized by the OEB in 2013. Regional planning assesses the interrelated needs of a region, which are 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.

Regional plans consider the existing electricity infrastructure in an area, forecast demand growth and customer reliability, evaluate a range of potential options for addressing needs, and recommend actions to be undertaken. The process is carried out by the IESO in collaboration with the applicable transmitter(s) and LDCs.

The current regional planning process is conducted on a five-year planning cycle for each of the province's 21 planning regions and consists of four main components:

- **Needs Assessment** – Led by the applicable transmitter, the Needs Assessment screens for electricity needs in the region and determines if there are requirements for further regional co-ordination.
- **Scoping Assessment** – Led by the IESO, the Scoping Assessment determines the most appropriate planning approach for identified needs and defines the scope of any recommended planning activities.
- **Integrated Regional Resource Plan** – Led by the IESO, the IRRP proposes recommendations to meet the identified needs requiring co-ordinated regional planning.
- **Regional Infrastructure Plan** – Led by the applicable transmitter, the RIP provides further technical detail for implementing recommended wires solutions.

In addition to regional planning, there are related bulk system planning and distribution system planning activities. Bulk system planning typically considers the 230 kV and 500 kV transmission networks and examines province-wide issues, while distribution planning assesses the adequacy and reliability of the LDC's own network. Regional planning operates at the interface of these two processes. Further details on the regional planning process and the IESO's approach to it can be found in Appendix A.

For the ELS region, the Needs Assessment completed in October 2024 identified several electricity system needs requiring co-ordinated regional planning. The subsequent Scoping Assessment concluded that an IRRP was the most appropriate planning approach, given the nature of the identified needs and the potential to consider a range of solutions, including NWAs. This IRRP represents the outcome of that co-ordinated regional planning effort.

3.2 IESO's Approach to Regional Planning

The IESO leads the IRRP stage of regional planning and is responsible for facilitating co-ordinated assessment of electricity system needs and potential solutions. The IESO's approach to regional planning emphasizes:

- Integrated assessment of transmission, distribution, and local resource options.
- Proportionality, ensuring that solutions are aligned with the magnitude, timing, and drivers of identified needs.
- Flexibility and optionality, preserving future decision-making where uncertainty exists.
- Transparency and engagement, enabling communities and stakeholders to understand and provide input into planning decisions.

In developing this IRRP, the IESO worked closely with the ELS TWG to assess system performance under forecast demand conditions and applicable contingencies, consistent with the ORTAC, North American Electric Reliability Corporation (NERC) standards, and Northeast Power Coordinating Council (NPCC) criteria.

A wide range of potential solutions was considered, including transmission and distribution reinforcements, local generation, demand-side resources, operational measures, and NWAs. Options were evaluated based on technical feasibility, timing, cost-effectiveness, and their ability to directly address the underlying causes of identified system needs. Preferred approaches were selected where they provided the most effective and proportionate means of maintaining system reliability.

3.3 ELS Technical Working Group and IRRP Development

The development of the ELS IRRP was supported by the ELS TWG, which serves as the primary technical forum for regional planning co-ordination. The TWG is composed of representatives from:

- the IESO;
- transmitters serving the ELS region including Hydro One Networks Inc., Hydro One Networks Sault Ste. Marie LP., and PUC Transmission LP; and
- local distribution companies operating within the region including Algoma Power Inc., Hydro One Distribution and PUC Distribution.

The TWG was responsible for:

- providing and reviewing regional demand forecast inputs and system data;
- identifying system constraints and verifying study assumptions;
- reviewing technical study results and option assessments; and
- supporting co-ordination between regional and bulk system planning activities.

Throughout the IRRP development process, the TWG met regularly to review analysis results, confirm findings, and provide input on the identification of preferred solutions. The TWG also supported engagement activities by helping to contextualize planning issues and respond to feedback received from communities and stakeholders.

The IRRP was developed through an iterative process, with findings from the needs assessment, technical studies, and engagement activities informing successive stages of analysis. This collaborative approach ensured that the final plan reflects a shared understanding of regional electricity system conditions and provides a co-ordinated path forward for addressing identified needs in the ELS region.

4. Background and Study Scope

4.1 Background

The ELS region is supplied by the provincial transmission system and is electrically bounded by the 230 kV transmission circuits from Wawa TS to the northwest and Mississagi TS to the southeast. The study reflects forecast electricity demand, including the effects of eDSM, distributed generation, and other planning assumptions relevant to the region.

The background for this planning cycle also reflects major developments already incorporated into the reference system and planning assumptions for the region. These include transmission reinforcements associated with the Northeast Bulk Reinforcement Plan, the staged completion of the Algoma Steel EAF project, and ongoing asset replacement and refurbishment activities affecting key regional facilities. Collectively, these developments materially strengthen the regional supply context and help address or defer previously identified longer-term constraints.

4.2 Study Scope

The scope of this IRRP was established through the Scoping Assessment process and focuses on electricity system needs requiring co-ordinated regional planning within the ELS region over the planning horizon. The assessment examines system performance under forecast demand conditions, applicable reliability criteria, and credible contingency scenarios to identify limitations that may affect the region's ability to reliably serve load.

The TWG, led by the IESO and supported by transmitters and local distribution companies serving the region, prepared the demand forecast, reviewed system conditions, assessed identified needs, and considered options to address those needs. The study examined:

- Bulk system connection points and their capacity to serve regional demand.
- Interfaces such as the East West Tie West/East and its operational constraints.
- Planned projects with approved investment plans or committed in-service dates.
- Single-line diagram representation of the system for clarity on supply configuration.
- 20-year demand forecast reflecting eDSM, Distributed Generation (DG), and Distributed Energy Resource (DER) contributions.

The load-meeting capability (LMC) and reliability of the existing transmission system, considering transmission facility performance including transformer ratings, line thermal limits, load security, and restoration capability.

Establishing needs and timing with LDCs and transmitters including any identified due to end-of-life asset replacement.

Establishing options and alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as NWA including eDSM.

The assessment uses the applicable planning standards (e.g., ORTAC, NERC) and relevant asset condition data.

Consistent with the OEB's regional planning framework, this IRRP considers a broad range of potential solution types and emphasizes solutions that are technically feasible, timely, cost-effective, and proportionate to the nature and timing of the identified needs. Needs that can be addressed through local planning or asset replacement programs alone are outside the direct scope of this IRRP unless co-ordinated regional planning is required.

The scope was developed to ensure that the plan addresses all identified near-, mid-, and long-term needs in a co-ordinated and cost-effective manner. Additional high sensitivity studies were performed for these areas to test the robustness of the system to supply higher than forecast demand.

4.3 Related Bulk Planning Activities

Regional planning is informed by and co-ordinated with related bulk planning work undertaken by the IESO. This may include bulk planning studies that are underway in parallel with the IRRP, as well as completed bulk studies and associated transmission projects whose outcomes have been incorporated into the planning assumptions for the region. Where bulk transmission facilities interface directly with a regional system, the outcomes of this work can have a significant impact on regional planning decisions.

Bulk planning work may identify upstream transmission reinforcements, transformer expansions, interface upgrades, reactive compensation needs, or other system developments that affect regional supply capability, reliability, and future options. Findings and recommendations from relevant bulk planning work are incorporated into this IRRP where they affect the region.

4.3.1 Ongoing Bulk Planning Studies

Bulk planning studies underway in parallel with this IRRP form part of the broader planning context for the ELS region and may influence future supply capability, planning assumptions, and longer-term development pathways. Co-ordination between regional and bulk planning work helps ensure that assumptions remain aligned as both studies progress.

For the ELS region, the North of Sudbury Bulk Plan is particularly relevant. That work is proceeding in parallel with this IRRP and is expected to strengthen the broader transmission backbone supplying northeastern Ontario. In particular, reinforcements identified through the North of Sudbury Bulk Plan are expected to strengthen the Timmins end of the system and, in turn, support the performance and capability of the new Timmins to Wawa transmission line now under development.

As this bulk planning work nears completion on a similar timeline to the ELS IRRP, it represents an important part of the broader system context for the region and should continue to be co-ordinated with regional planning assumptions and future implementation activities.

4.3.2 Bulk Planning Outcomes Incorporated into this IRRP

This IRRP reflects the outcomes of previously completed bulk planning work that materially affects the ELS region, including the Northeast Bulk Reinforcement Plan and the Northern Ontario Voltage Study. These planning outcomes form part of the reference system and assumptions used in the regional needs assessment and options analysis.

For the ELS region, the Northeast Bulk Reinforcement Plan is particularly important because it provides upstream transmission capacity improvements that strengthen supply into northeast Ontario and improve the broader system conditions against which regional needs are assessed. The recommendations arising from the ELS study rely on upstream bulk transmission capacity that is enabled through the Northeast Bulk Reinforcement portfolio. The relevant reinforcements that support the ELS study include the new single 500 kV line between Mississagi TS and Hanmer TS (Northeast Power Line) and the new 230 kV double circuit line between Mississagi TS and Third Line TS (Northshore Link). The Northeast Bulk Reinforcement Plan supports the regional planning assumptions in this IRRP as it helps address the upstream system constraints in interfaces such as the Mississagi West/East and ensures reliable supply to the Sault Ste. Marie area. Both lines are essentially critical to supporting the load growth in the area and in providing additional capacity in the Northeast region.

Similarly, the outcomes from the Northern Ontario Voltage Study play a key role in the final recommendations in the ELS IRRP. These outcomes include system reactive compensation in Mississagi TS and Algoma TS, which have been used as an input and a study assumption into the plan. These reactive compensations inform and influence the options analysis and draft recommendations in this IRRP as they generally help improve post-contingency transient voltage performance in the region. They also benefit normal operation voltage control to reduce impact from load fluctuations. Without these devices, the options found in the IRRP would need to be reassessed to ensure that the needs in the region are fully addressed.

4.3.3 Ongoing Bulk Implementation Activities

Implementation of previously identified bulk planning outcomes is underway and forms an important part of the planning context for the ELS region. These activities are outside the direct scope of this IRRP, but they materially affect the regional supply context by strengthening upstream transmission capability and reinforcing the broader system on which the region depends.

In particular, three major transmission line projects associated with the Northeast Bulk Reinforcement are currently under development: the Northeast Power Line (Hanmer TS to Mississagi TS), the North Shore Link (Mississagi TS to Third Line TS), and the Timmins to Wawa Transmission Line (Porcupine TS to Wawa TS). Together, these projects strengthen the transmission supply to the ELS region and more broadly northeast Ontario.

These implementation activities are especially important for the ELS region because they strengthen supply into Wawa and Third Line, which are key supply points for the regional system. In combination with other system developments, they help establish the reference system against which the needs and recommendations in this IRRP have been assessed.

5. Electricity Demand Forecast

The ELS region load forecast establishes the foundation for identifying electricity system needs and developing planning options. The forecast is based on assumptions regarding population growth, economic activity, electrification trends, and other local drivers, as well as provincial planning standards and criteria. Peak demand forecasts consider both reliability requirements and the contribution from planned eDSM and DG.

The forecast development process begins with a review of historical summer and winter peak demand to establish a baseline. LDCs then provide gross demand forecasts that incorporate anticipated customer growth and connection activity. Weather correction is then applied to develop an extreme weather forecast for planning purposes. Adjustments are subsequently made to reflect the expected contributions of eDSM and DG, yielding the net planning forecast. This forecast is used to assess system adequacy and identify potential needs. In addition to annual peak demand forecasts, hourly load profiles are created to support system studies and evaluate planning options.

The forecast was developed using a 20-year planning horizon for the years 2025–2044 and consists of two components: the distribution-connected forecast and transmission connected forecast.

- **Distribution-connected**: The distribution-connected forecast reflects demand served on the distribution systems in the ELS region and is based on information submitted by LDCs. The regional planning process relies on LDCs to consider municipal and regional official plans and Indigenous community development plans and translate them 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 and Indigenous communities they serve.
- **Transmission-connected**: The transmission-connected forecast reflects demand served directly from the transmission system. This typically consists of large industrial customers that have their own transformation stations. The transmission-connected forecast is informed by direct engagement with these customers.

Either coincident or non-coincident peaks are used to develop these forecasts. The coincident peaks refer to the sum of each station's demand in the region taken at the hour when the whole region's demand is at its maximum. Meanwhile, the non-coincident peaks refer to the sum of each station's demand in the region taken at the hour where they individually peak, regardless of whether or not these peaks occur at different times.

In this plan, non-coincident peak load was assumed at each station for the region.

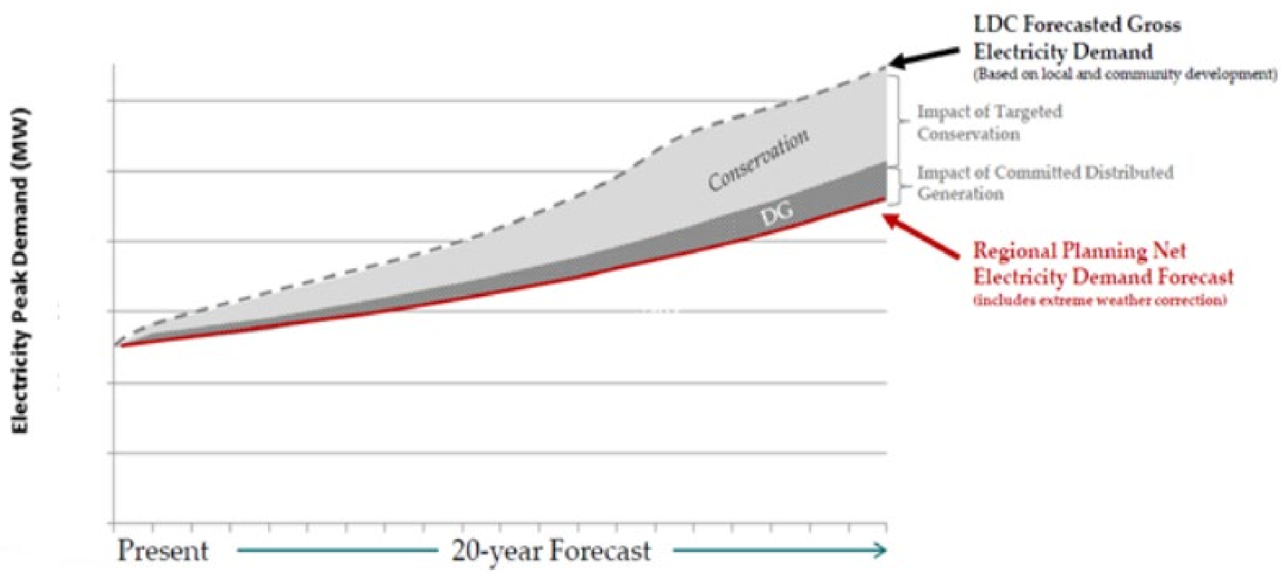
5.1 Demand Forecast Methodology

The methodology used to develop a 20-year IRRP peak demand forecast is shown in Figure 4. A gross demand forecast, which assumes normal weather conditions based on historical weather patterns (referred to as "normal weather"), was developed by the LDCs. This forecast was then adjusted to reflect the expected impact of extreme weather conditions for planning purposes.

Extreme weather conditions, as defined by the IESO, assume the worst observed weather over the previous 30 years. The forecast was then modified to reflect the expected peak demand impacts of provincial electricity demand side management programs and DG contracted through previous provincial programs, such as renewable Feed-In Tariff (FIT) and microFIT standard offer programs. The resulting planning demand forecast was used to assess electricity needs in the region.

The demand forecast methodology is also informed by the Load Forecast Guideline for regional planning, which was formalized by the OEB's Regional Planning Process Advisory Group. The development of the demand forecast is further explained in Appendix B.

Figure 4 | Illustrative Development of Demand Forecast

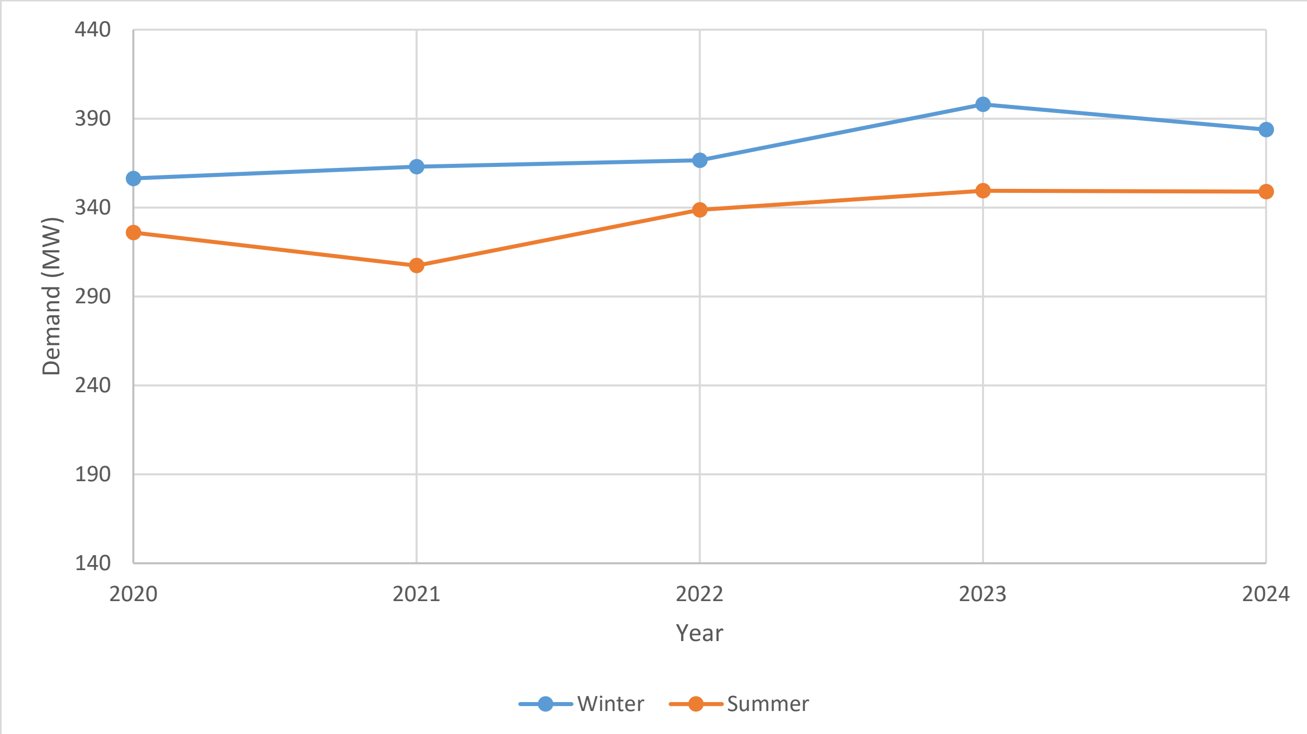


5.2 Historical Demand

Historically, the ELS region has been a winter peaking region where the peak hour for each year typically occurs in the evening, driven by electrical heating demand in the residential sector as access to natural gas is limited in the area.

The historical demand in the region for both seasons has been generally increasing, though demand has remained between 300 and 400 MW over the course of the years. Over the past five years, the demand for the region has averaged 375 MW in the winter and 335 MW in the summer. Figure 5 illustrates historical peak demand in the ELS region over the 2020 to 2024 period.

Figure 5 | Historical Peak Net Demand (2020-2024)

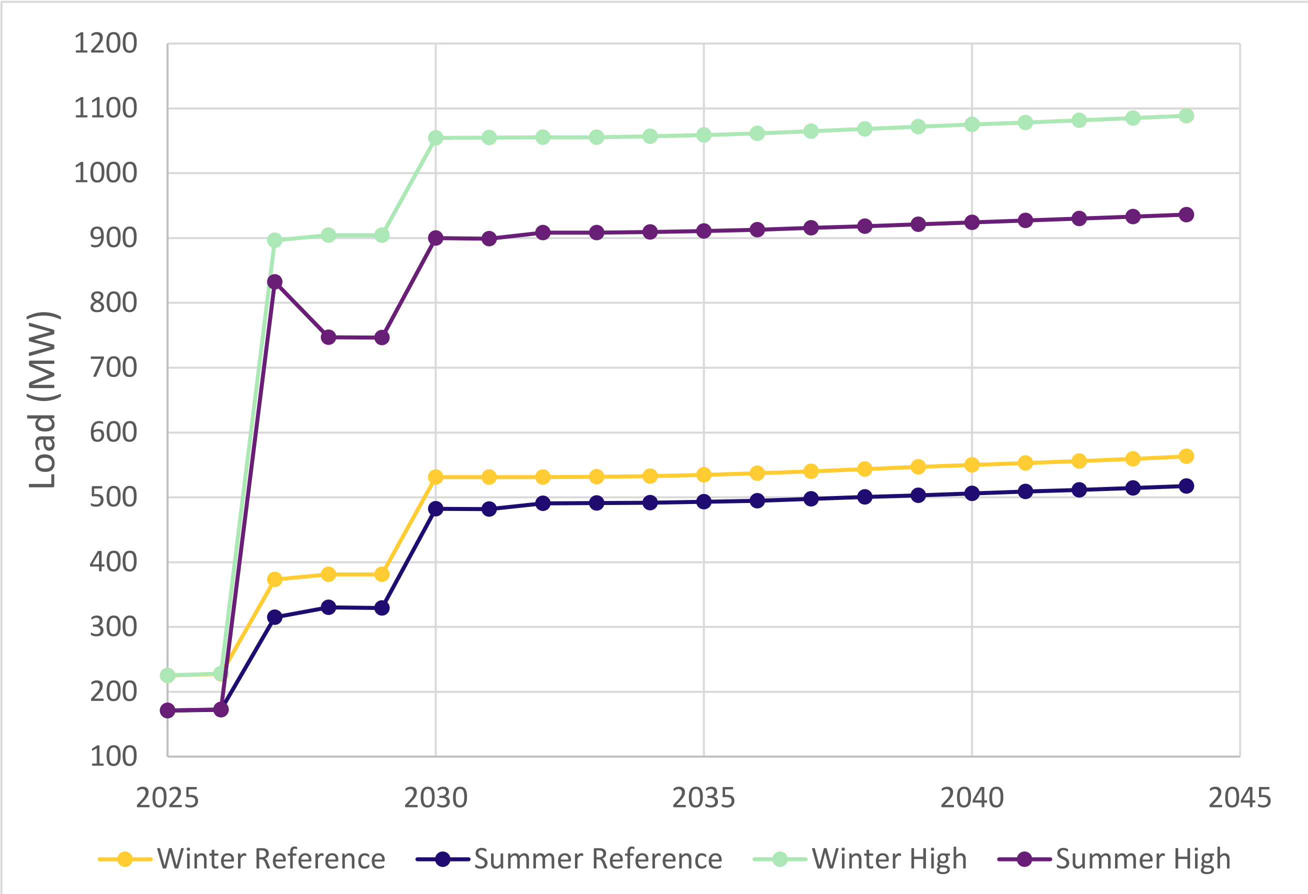


5.3 Gross Local Distribution Company Forecast

Each participating LDC prepared gross demand forecasts at the station level or at the station bus level for multi-bus stations. These forecasts account for expected changes in demand arising from efficiency improvements, rising electricity prices, and new or intensified developments. The LDC forecasts are developed based on their understanding of known local development plans and information from customer engagements. Their forecasts, however, do not include the effects of planned eDSM and DG, as they are incorporated separately by the IESO. A reference and high forecast were provided by each LDC. Additional details on each LDC's forecast methodology are provided in Appendix B.2.

The compiled distribution-connected forecasts were then adjusted to reflect extreme weather conditions. The impacts of eDSM and distributed generation were then applied separately, consistent with the forecast methodology described above. The resulting distribution-connected forecast is shown in Figure 6.

Figure 6 | Net Extreme Weather Distribution-Connected Forecast



5.4 Contribution of eDSM to the Forecast

EDSM[4] is a clean and cost-effective resource aimed to help meet the electricity needs in the province of Ontario by reducing electricity consumption and peak demand in the region. This is achieved through a combination of codes and standards amendments as well as eDSM programs, primarily the suite of Save on Energy programs, to maximize conservation results.

The reduction of demand from the codes and standards amendments is dependent on the revised codes and standards set by new or renovated buildings as well as regulation of minimum efficiency standards set by equipment used in different sectors including residential, industrial, and commercial areas.

The estimated reduction of demand due to program-related activities is based on the IESO's 2025 Annual Planning Outlook eDSM savings forecast, which is informed by the IESO's 2021–2024 CDM Framework programs, the 2025–2027 Program Plan of the new 2025–2036 eDSM Framework, existing federal programs that reduce electricity needs in Ontario and expected long-term eDSM

[4] In alignment with the language of the November 7, 2024 directive to the IESO regarding a new program framework for 2025-2036, this IRRP uses the term "Electricity Demand-Side Management" ("eDSM"), replacing "Conservation and Demand Management" used in previous IRRPs and other IESO planning documents.

program savings aligned with the current Program Plan. Following the conclusion of the 2021-2024 CDM Framework, the new 2025–2036 eDSM Framework was launched in the beginning of 2025, which expands the scale and scope of the Save-On Energy programs including launch of the Home Renovation Savings programs for residential customers and various other new incentives.

As a result, Figure 7 and Figure 8 show the total contribution of eDSM for the ELS region in the winter and summer respectively under the reference scenario, reducing the total yearly peak demand for both seasons. They are divided into three sectors including residential, commercial, and industrial.

Figure 7 | Winter Reference Peak Demand Reduction Due to eDSM

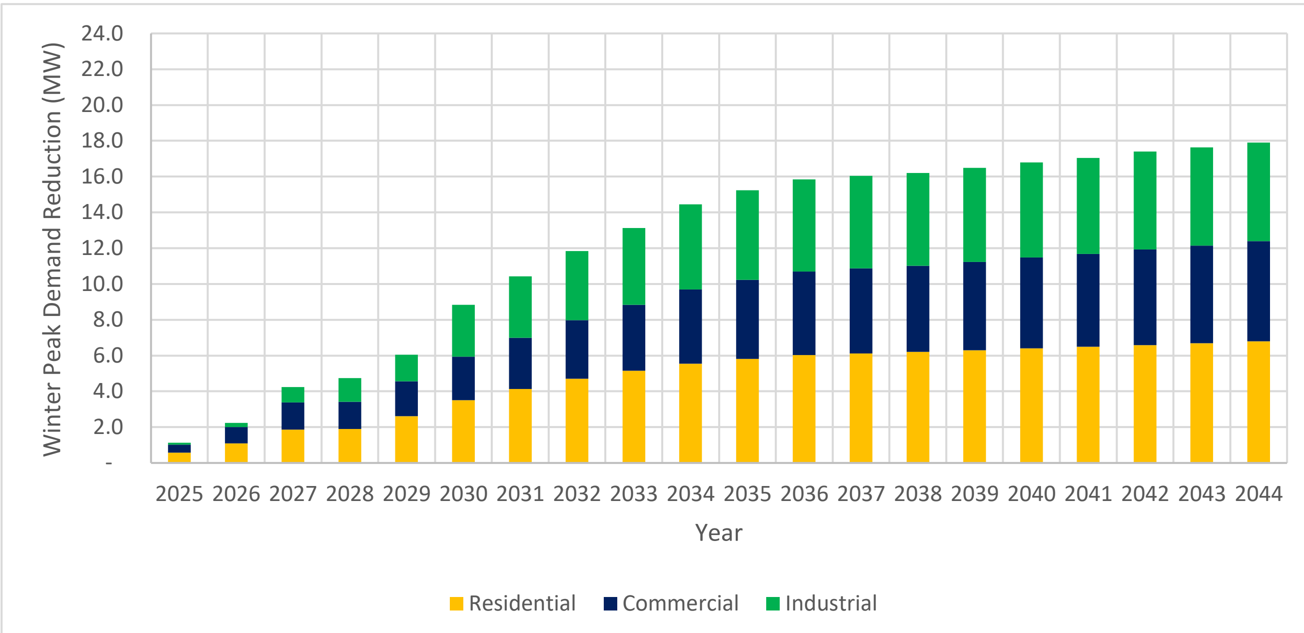
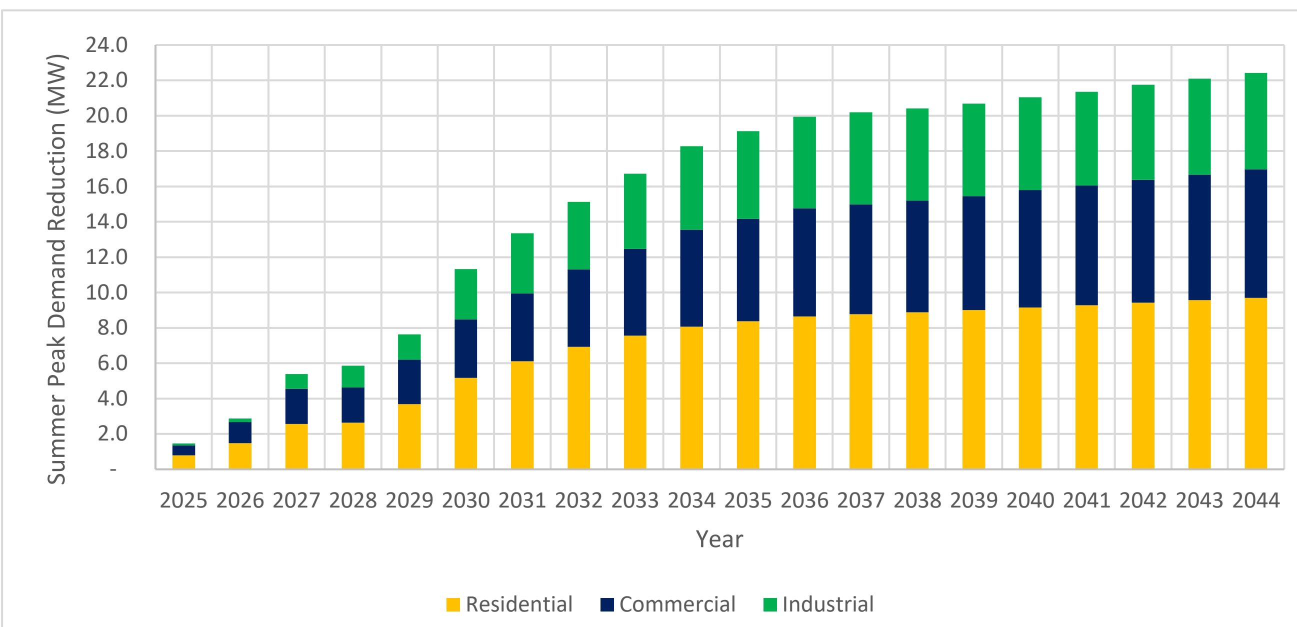


Figure 8 | Summer Reference Peak Demand Reduction Due to eDSM

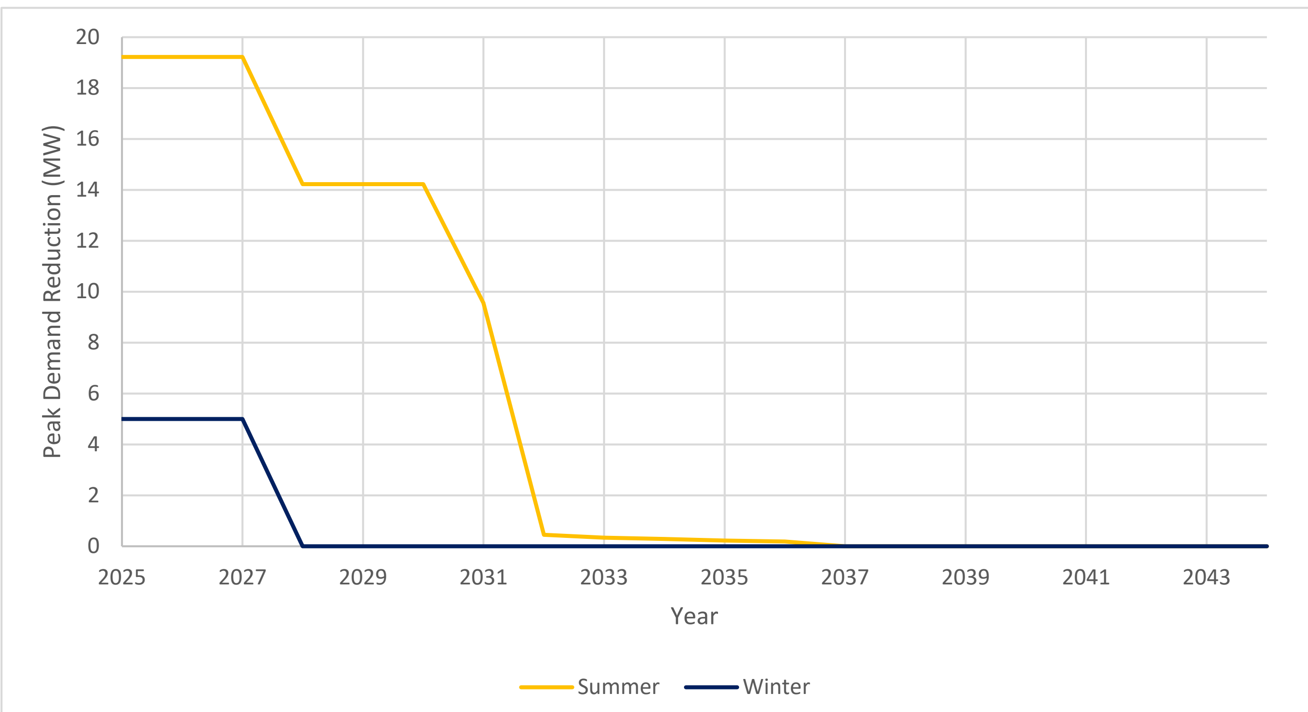


5.5 Contribution of Distributed Generation to the Forecast

Apart from eDSM resources, DG also plays a key role in reducing the electricity needs in the region. This includes resources contracted under the Ontario FIT and microFIT programs which were developed upon the introduction of the Green Energy and Green Economy Act in 2009. This act was aimed to expand renewable energy capacity across the province, encourage energy conservation and efficiency, and promote green jobs. These resources help offset peak demand requirements in regions such as the ELS region.

In Figure 9, the contribution of DG to the forecast is shown. This contribution is accounted for in the forecast, which further reduces the annual peak in addition to the contribution of eDSM. It is important to note that only facilities under contract with the IESO are accounted for and included into this forecast. As shown in Figure 9, the peak demand reduction over the years decreases. This is due to contracts expiring significantly in the middle of the next decade. The declining contribution of DG is expected to be addressed through continued implementation of the various Resource Adequacy Framework procurement mechanisms. Re-contracting of existing resources will be prioritized through upcoming windows of the Medium-Term Request for Proposals (RFP), the annual Capacity Auction and new procurement initiatives, such as the Local Generation Program. Repowering of existing resources reaching end of useful life is also being explored through the Long-Term RFP. If additional supply is required, procurement of new resources will be implemented.

Figure 9 | Peak Demand Reduction Due to DG

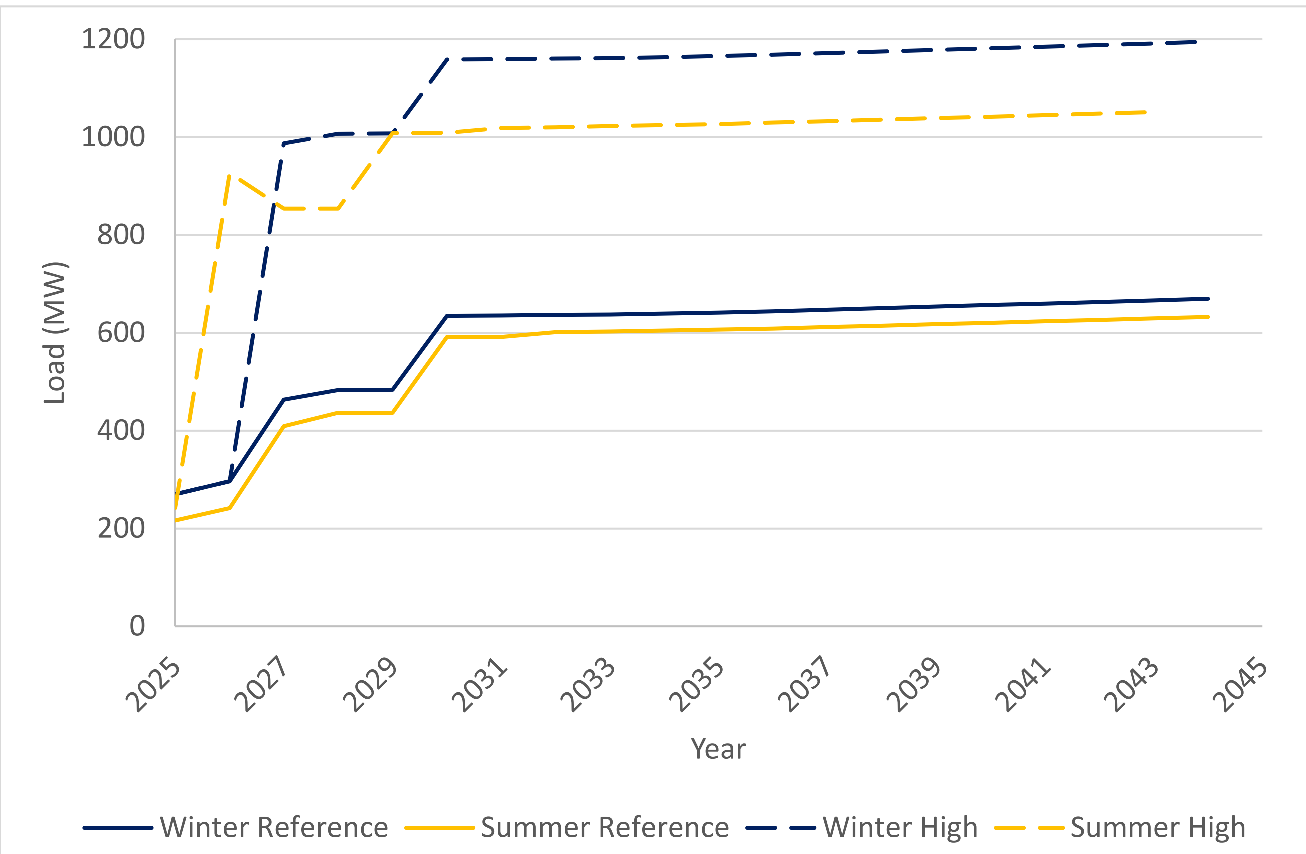


5.6 Planning Demand Forecast

After compiling the gross median forecasts from the LDCs and applying the weather correction factor and contributions of eDSM and DG, the net extreme forecast is achieved. Typically, the weather correction factor is first applied to the LDC forecast to obtain the gross extreme forecast. Then, the impact of eDSM and DG is deducted from the forecast to produce the net extreme forecast. The resulting net extreme weather demand forecast is then used to identify electricity system needs in the region and to inform the technical studies to develop options and recommendations.

The net extreme weather demand forecast for the ELS region is shown in Figure 10. This forecast includes the reference and high scenarios for each season and combines the distribution-connected and transmission-connected components of the forecast. In the winter reference scenario, the electricity demand grows significantly by 114% from 2026–2030 and stabilizes by year 2030. Also, its average annual growth rate throughout the planning period is approximately 5%. Similarly, in the winter high scenario, the same trend is observed. However, in the winter high scenario, demand could grow by 290% from 2026-2030, where the scenario encompasses potential customer connections in minerals processing, data centres, and construction. Its average annual growth rate throughout the planning period is also observed to be approximately 8%.

Figure 10 | Final ELS Net Extreme Weather Forecast



5.7 Hourly Forecast Profiles

In addition to the annual peak demand forecast, hourly demand profiles were also developed to support the evaluation of NWAs to address regional needs. These profiles were created for all 8,760 hours of the year over the 20-year forecast horizon for various stations and groups of stations. They were used to quantify the magnitude, frequency, and duration of needs. This supports the analysis of potential NWAs. The profiles are based on historical demand data, adjusted for variables that impact demand such as calendar day (i.e., holidays and weekends) and weather. They are then scaled to match the IRRP peak planning forecast for each year. Additional details on the hourly forecasting methodology are further provided in Appendix B.6

Note that these profiles are not intended to deterministically define hourly energy needs for NWAs. Instead, they provide a reasonable approximation of energy requirements for planning purposes, including estimating operating costs and selecting appropriate technologies. As consumer behaviour evolves, new businesses emerge, and electrification trends accelerate, demand patterns may shift significantly. The TWG will continue to monitor these developments as part of the ongoing planning process.

6. Electricity System Needs

This section summarizes the electricity system needs identified through the IRRP process for the ELS region. The assessment considers projected demand growth, electrification, and decarbonization trends, which are expected to increase pressure on the electricity system over the planning horizon, particularly during winter peak periods. The needs assessment methodology and the resulting electricity needs are described in the sections below.

6.1 Needs Assessment Methodology

Electricity needs were identified by the TWG based on an integrated assessment of planning demand forecasts, existing and forecasted system capability, the transmitter's identified asset replacement plans, and the application of established power system reliability standards and criteria, including ORTAC, NERC standards, and NPCC criteria.

Technical studies were conducted using industry-standard power system simulation tools to assess system performance under forecasted peak demand conditions and applicable contingency events. Based on this analysis, electricity needs were identified in the near-, medium-, and long-term timeframes and are categorized as follows.

Station Capacity Needs

Station capacity needs describe the electricity system's inability to deliver power to the local distribution network through regional step-down transformer stations during periods of peak demand. The capacity rating of a transformer station represents the maximum demand that can be reliably supplied and is constrained by station equipment.

Station capacity is typically determined based on the 10-day Limited Time Rating (LTR) of the station's smallest transformer, under the assumption that the largest transformer is out of service. In some cases, station capability may also be limited by the thermal or voltage constraints of upstream or downstream equipment, such as breakers, disconnect switches, low- or medium-voltage buses, or high-voltage circuits. Voltage drop limitations may further restrict station capacity independently of thermal ratings.

Supply Capacity Needs

Supply capacity needs describe the electricity system's inability to provide continuous electricity supply to a local area during peak demand conditions. These needs are defined by the LMC of the transmission system supplying the area.

LMC is determined by evaluating the maximum demand that can be served after accounting for the limitations of transmission elements—such as transmission lines, groups of lines, or autotransformers—when subjected to contingencies and criteria prescribed by ORTAC, NERC TPL-001-5.1, and NPCC Directory #1. LMC assessments are conducted using power system simulation analyses and may consider normal or extreme weather demand conditions, as applicable.

Asset Replacement Needs

Asset replacement needs are identified by the transmitter based on asset condition assessments and long-term asset management planning. These assessments consider a range of factors, including equipment deterioration due to age, weathering, or thermal stress; technical obsolescence associated with outdated designs; limited availability of spare parts or manufacturer support; and potential health and safety risks.

Asset replacement needs identified in the near- and early medium-term timeframes typically reflect condition-based information, while medium- and long-term replacement needs are often informed by the expected service life of equipment. As asset condition information is routinely updated, the timing of medium- and long-term replacement needs may change, and recommended need dates should be considered indicative.

Load Security and Load Restoration Needs

Load security and load restoration needs describe the electricity system's ability to minimize the impact of major transmission outages on customers. These needs are typically associated with severe but credible events, such as the loss of both circuits on a double circuit transmission line.

Load security refers to the total amount of customer demand that would be interrupted following a major transmission outage, while load restoration describes the system's ability to restore service to affected customers within reasonable timeframes. The specific load security and restoration requirements applied in this assessment are prescribed by ORTAC.

Based on the application of the needs assessment methodology described above, four electricity system needs were identified within the ELS study area. All identified needs are expected to emerge in the near-term, generally within the next five years, and therefore require timely action. The identified needs are limited to two categories: station capacity needs and supply capacity needs. With the inclusion of the Northeast Bulk Reinforcement, no new or distinct medium- or long-term electricity needs were identified over the planning horizon. Accordingly, the focus of this report is on addressing near-term system limitations, which are discussed in detail in the sections that follow.

6.2 Station Capacity Needs

Station capacity needs are determined by comparing forecast peak demand at step-down transformer stations with the available station capacity. For stations with multiple transformers, available capacity is typically defined using the 10-day LTR of the smallest transformer, assuming the largest transformer is out of service, in accordance with ORTAC. For single-transformer stations, available capacity is based on the transformer's continuous rating.

The asset owner is responsible for establishing transformer ratings. In most cases, the nameplate rating is used; however, in certain instances, a revised continuous rating may be calculated and applied.

Where feasible, load transfers between nearby stations are incorporated into the station-level demand forecast. These assumptions are based on information provided by local distribution company members of the TWG regarding transfer capabilities and normal operating practices.

Station capacity assessments consider both summer and winter peak demand conditions. While transformer thermal ratings are often lower in summer, increasing electrification and electric heating load can result in winter peak demand being more restrictive. As a result, both seasonal conditions are evaluated to identify the most constraining scenario.

Based on this assessment, no station capacity needs are identified in the ELS region under the Reference Scenario, as described below.

6.2.1 Chapleau DS Station Capacity Need

Based on the updated demand forecast and revised station capacity assessment methodology, Chapleau DS does not exhibit an existing or near-term station capacity need. Under the Reference Scenario, forecast station loading remains within available capacity for both summer and winter peak conditions throughout the study period. Under the High Growth Scenario, load increases more rapidly, with a station capacity need emerging in the late-2030s, driven primarily by summer peak demand.

Earlier assessments identified a potential station capacity limitation at Chapleau DS based on preliminary assumptions related to power factor, treatment of local cogeneration output, and the use of nameplate continuous transformer ratings to define available capacity. These assumptions have since been refined, and the station capacity assessment has been updated to reflect revised demand forecasting inputs and current Hydro One Distribution planning criteria.

Specifically, updated power factor values provided by Hydro One Distribution were incorporated into the station-level demand forecast. In addition, the treatment of the local biomass cogeneration facility was revised such that only generation coincident with system peak demand is credited, rather than the facility's allocated capacity. The forecast was also adjusted to a new baseline by subtracting the difference between the previous and updated starting points, ensuring alignment with observed station loading conditions. Collectively, these refinements result in a more accurate representation of net peak demand at Chapleau DS.

Chapleau DS is supplied by a single step-down transformer (T2) with nameplate ratings of 7.5 MVA under natural cooling (Oil Natural Air Natural, ONAN) and 11 MVA under fan-assisted cooling (Oil Natural Air Forced, ONAF). As fan monitoring is installed at the station, the 11 MVA ONAF rating is considered available under normal operating conditions. Unlike earlier assessments, which implicitly relied on the transformer's nameplate continuous rating, the current assessment applies Hydro One Distribution's Planned Loading Limit (PLL) methodology, which permits defined levels of continuous transformer loading above the nameplate rating.

Consistent with Hydro One Distribution planning standards, the applicable PLL factors are 125% of the ONAF rating under summer peak conditions and 155–160% under winter peak conditions, resulting in available station capacities of approximately 13.75 MVA in summer and 17 MVA in winter. When assessed against these PLL-based ratings, forecast summer and winter peak demand remains within available station capacity throughout the study period under the Reference Scenario.

As a single-transformer supplied station, Chapleau DS does not meet firm N-1 capability under transformer outage conditions. In the event of a transformer outage, continued supply would rely on the deployment of a Mobile Substation Unit (MSU). The maximum available MSU size for the

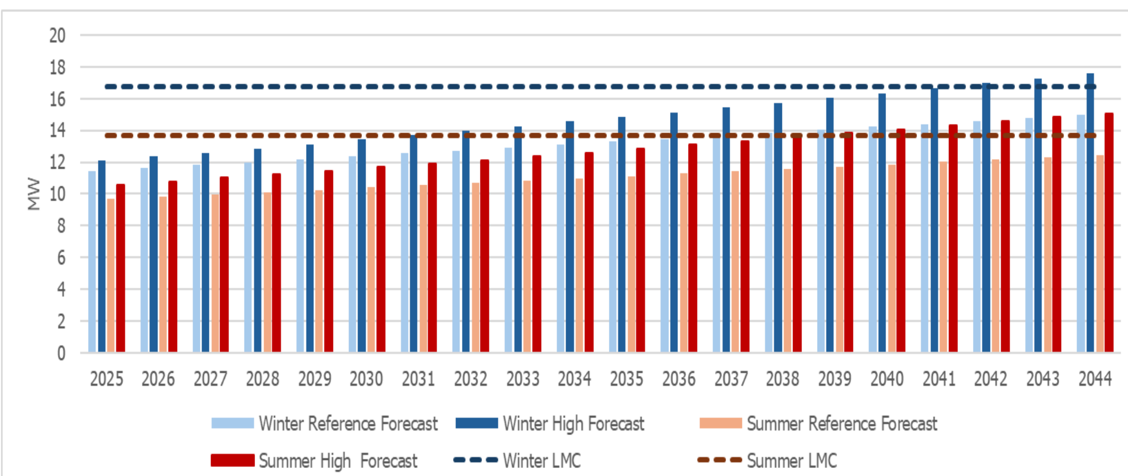
Chapleau area is 15 MVA, which effectively defines the station's supply capability under contingency conditions. While reliance on a MSU reduces operating margins during peak periods, particularly in winter; this represents a contingency-driven limitation, rather than a firm station capacity deficiency under normal operating conditions.

Overall, with the incorporation of updated power factor assumptions, revised treatment of cogeneration output at system peak, baseline-aligned demand forecasting, and the application of Hydro One Distribution's PLL methodology, Chapleau DS does not exhibit an existing or near-term station capacity need under the Reference Scenario. Forecast summer and winter peak demand remain within available station capacity throughout the study period. While a station capacity need is indicated under the High Growth Scenario in the late-2030s, this sensitivity is used to test robustness and timing rather than to establish need. Accordingly, Chapleau DS does not have an identified station capacity need in this IRRP; however, higher-growth sensitivities suggest when a capacity need could emerge should demand materially exceed the reference forecast.

Table 4 | Summary of Station Capacity Assessment – Chapleau DS

Scenario	Limiting Season	Result
Reference	Winter	No station capacity need
Reference	Summer	No station capacity need
High	Winter	Capacity need in late-2030s
High	Summer	Capacity need in late-2030s

Figure 11 | Chapleau DS Demand vs. LMC



6.3 Supply Capacity Needs

Supply capacity needs in the ELS region are associated with limitations in the ability of the transmission system to reliably supply forecast demand under applicable contingency conditions. These needs are defined by the LMC of the transmission system supplying the area and are assessed in accordance with ORTAC, NERC TPL-001-5.1, and NPCC Directory #1 criteria.

LMC assessments were conducted using industry-standard power system simulation analyses to evaluate the maximum demand that can be reliably served while maintaining compliance with applicable contingency requirements. Where system reliability depends on local generation, sensitivity analyses were performed to assess the impact of generation outages, consistent with ORTAC requirements.

Based on this assessment, three supply capacity needs were identified in the ELS region. Each is linked to a distinct transmission supply interface or corridor, as described in the sections below.

6.3.1 Chapleau Area Supply Capacity Need (W2C Supply Path)

A supply capacity need is expected to emerge in the Chapleau area, affecting both Chapleau DS and Chapleau DS2, which are supplied via the 115 kV W2C transmission path. While the transmission facilities are capable of thermally supplying forecast load, the ability of the system to reliably serve peak demand is constrained by voltage limitations at the Chapleau end of the transmission line.

This supply capacity need is distinct from station capacity considerations identified in the previous section, as it is driven by voltage performance on the W2C transmission path rather than transformer thermal capability at Chapleau DS.

As load increases, voltages in the Chapleau area are reduced and fall below the minimum voltage levels specified in planning criteria. This limits the load meeting capability of the W2C supply path and results in a supply capacity shortfall.

The voltage-limited supply capacity need is driven by forecast demand growth in the Chapleau area and potential increased reliance on the transmission system in the event that approximately 5 MW of local biomass cogeneration does not continue beyond the current contract term. While the future status of this facility is uncertain and no confirmed retirement has been communicated, the assessment conservatively considers a reduction in local generation to test system capability and inform planning.

The Chapleau area supply capacity need is expected to emerge in the near-term planning horizon and increases over time as demand continues to grow.

Figure 12 | Chapleau Area Demand vs. LMC

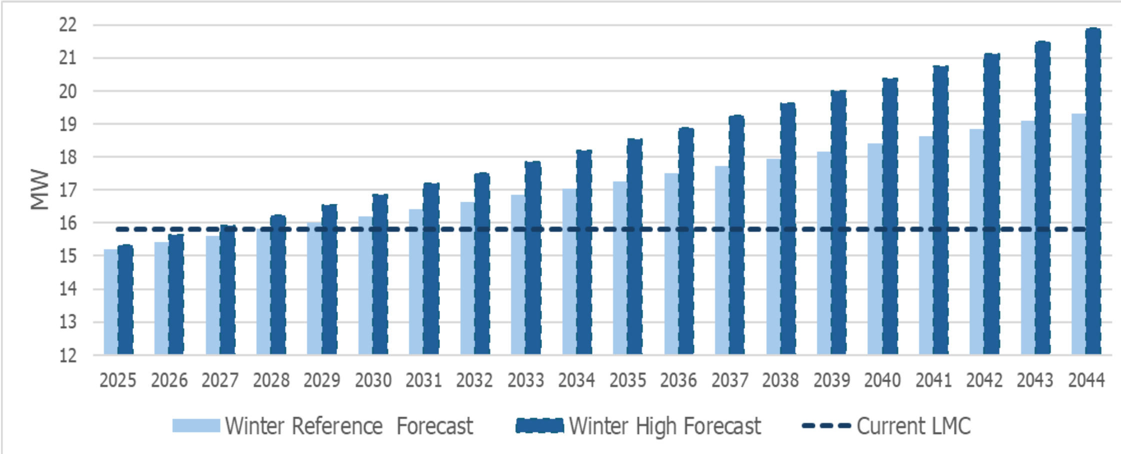
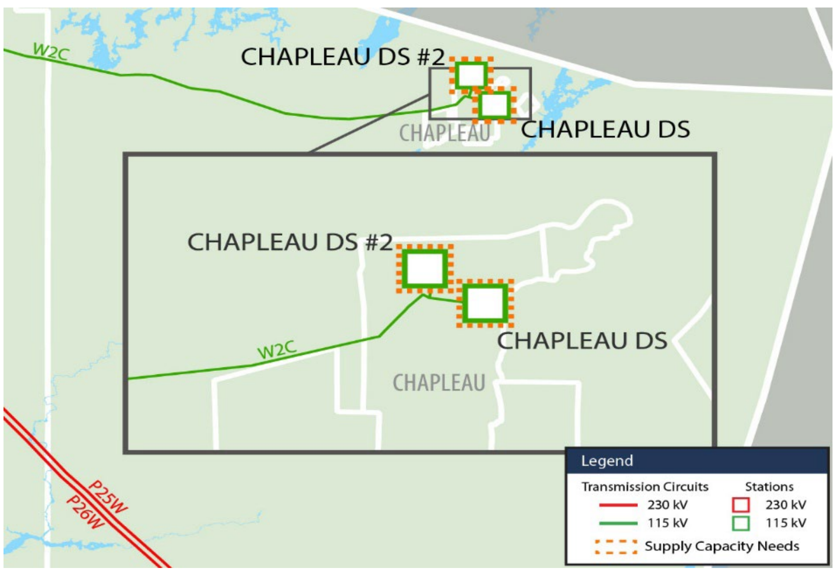


Figure 13 | Chapleau Area Need Map



6.3.2 Algoma 115 kV Interface Supply Capacity Need

A supply capacity need was identified at the Algoma 115 kV interface, which supplies load at Patrick Street, Flakeboard, and Wallace Terrace through three 115 kV transmission circuits (Algoma 1, Algoma 2, and Algoma 3). The interface also includes Clergue Generating Station, a local hydroelectric facility that provides dependable capacity to support load within the area.

The Algoma 115 kV interface reflects an existing transmission limitation rather than a need driven by forecast growth. No transmission reinforcements, generation additions, or material load growth are forecast within the study horizon. Despite the stable demand outlook, the interface is unable to meet applicable planning criteria under certain contingency conditions due to limitations in transmission transfer capability.

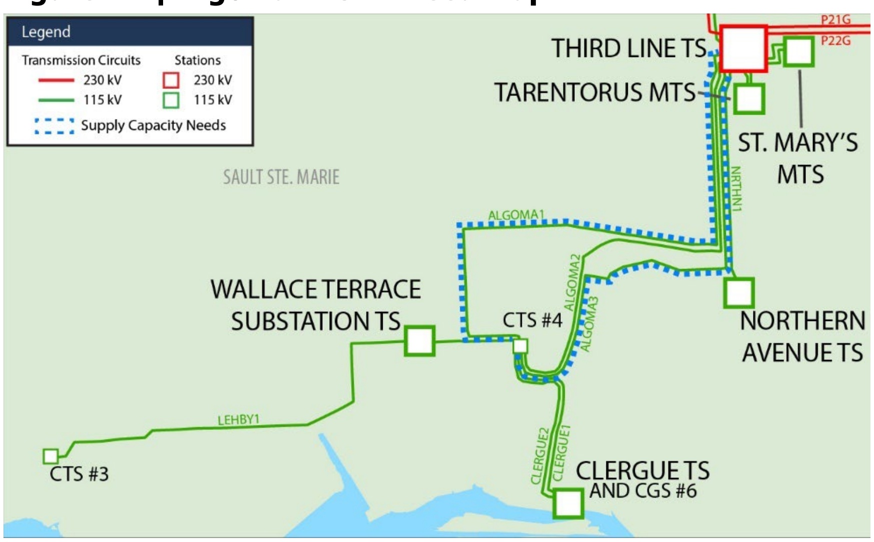
The identified supply capacity limitation is driven by the thermal performance of the Algoma 115 kV transmission lines under credible breaker failure and multiple-element outage contingencies.

Specifically, the loss of two Algoma circuits results in the remaining circuit, Algoma 1, which has the lowest thermal rating, being required to supply the full area load. Under these conditions, post-contingency loading exceeds applicable emergency thermal ratings, limiting the ability of the transmission system to reliably supply load in compliance with planning criteria.

To manage this condition, a RAS is currently in place that trips load within the Algoma interface under specific contingency scenarios. However, operation of the RAS can result in the interruption of more than 150 MW of customer load, exceeding the maximum allowable load rejection specified in ORTAC. Accordingly, the Algoma 115 kV interface does not satisfy planning criteria under these contingencies, even though forecast demand does not exceed the calculated load-meeting capability when non-compliant load rejection is assumed.

The impact of this limitation is mitigated in the near-term by local generation support from Lake Superior Power (LSP), which supplies load within the broader Sault Ste. Marie 115 kV System interface. This support reduces net loading on the Algoma facilities under contingency conditions, lowering the likelihood of thermal overloads following multiple element outages. However, for the purpose of need determination in this IRRP, planning criteria are applied without reliance on contracted generation such as LSP as firm supply. As a result, while LSP improves actual operating conditions, it is not assumed to be available in the planning assessment due to the treatment of contracted generation in the supply outlook. On this basis, the Algoma 115 kV interface continues to exhibit a supply capacity need under applicable planning criteria and must be identified in this IRRP.

Figure 14 | Algoma 115kV Need Map



6.3.3 Sault Ste. Marie Interface Supply Capacity Need

A supply capacity need has been identified for the Sault Ste. Marie 115 kV system interface, which supplies the majority of load within the Sault Ste. Marie area. The interface is anchored by Third Line TS, where power is transformed from the 230 kV system to the 115 kV system. For the purposes of this assessment, the interface includes the two 230/115 kV autotransformers at Third Line TS along with the 115 kV transmission circuit from Mackay TS to Batchawana TS (K3G) [5] and associated downstream facilities.

Under normal operating conditions and single-contingency events, the Sault Ste. Marie 115 kV system is able to reliably serve forecast load and remains compliant with applicable planning criteria. However, a supply capacity limitation arises under a two-element contingency involving the loss of both autotransformers at Third Line TS.

Following the loss of both autotransformers, the 115 kV system must supply the full area load without support from the 230 kV system. Under these conditions, the remaining 115 kV network, including the K3G transmission line, is not sufficient to support the forecast demand. Voltage instability and thermal overloads limit the transfer capability of the interface, and as a result, the available supply is not sufficient to reliably serve load in accordance with planning criteria.

Figure 15 | Sault Ste. Marie Demand vs. LMC

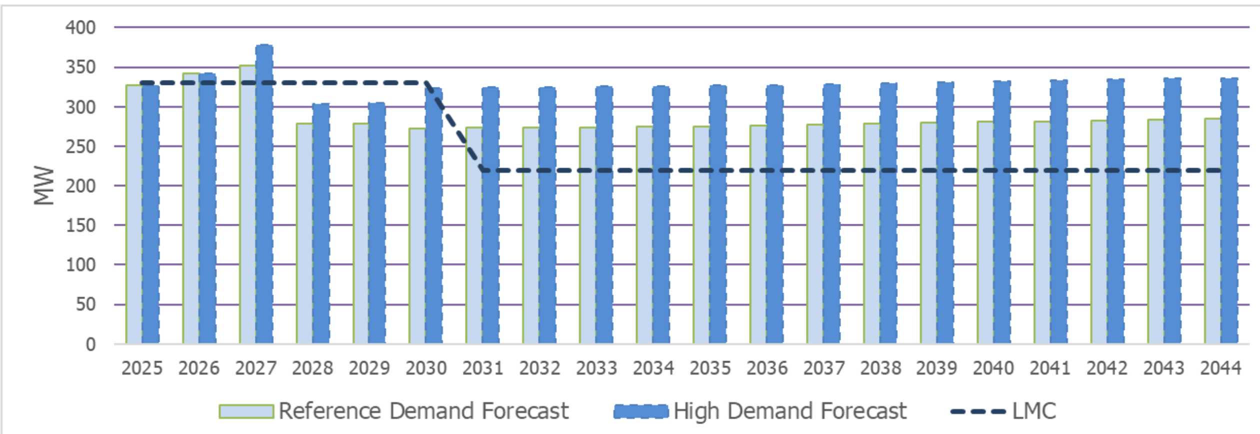
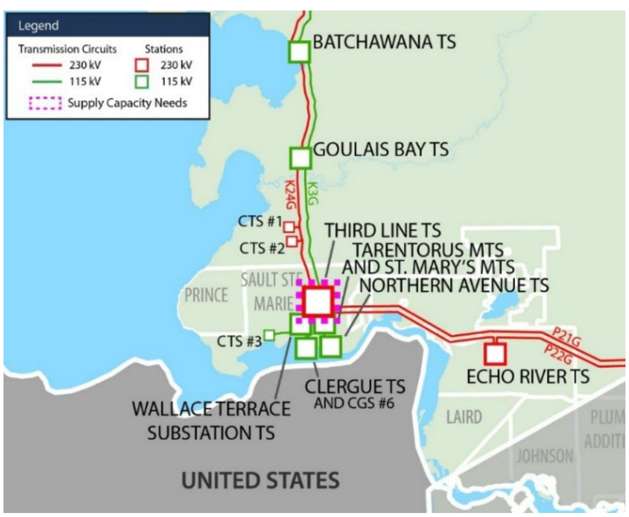


Figure 16 | Sault Ste. Marie Need Map



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[5] For clarity, the 115 kV transmission circuit historically referred to as "Sault No. 3" has been re-designated as K3G following system updates.

6.4 Summary of Identified Needs

The identified needs were evaluated considering their timing, likelihood, and underlying drivers. The solution assessment therefore emphasizes proportional, flexible approaches that maintain compliance with reliability criteria while avoiding premature infrastructure investment.

Table 5 below provides an overview of all the Planning needs identified in this IRRP.

Table 5 | Summary of Planning Needs in ELS Region

Need	Need Date	2044 Need (MW)
Chapleau DS station capacity	None	n/a
Chapleau Area Supply Capacity Need (W2C Supply Path)	2028	5
Algoma 115 kV interface Supply Capacity Need	N/A	0[6]
Sault Ste. Marie Interface Supply Capacity Need	2030	95

[6] The Algoma 115 kV interface can accommodate the demand forecast under planning criteria, which permit the use of RAS schemes to trip up to 150 MW of load. However, the existing RAS is not sufficiently selective and can result in load rejection exceeding 150 MW, requiring updates to achieve compliance.

7. Plan Options and Recommendations

This section describes the solutions identified to address the electricity system needs outlined in Section 6 and presents the recommended actions for the ELS region.

A range of potential solutions were evaluated, including transmission, generation, demand-side, and operational alternatives. Options were assessed based on their ability to address the identified needs within the required timeframe, improve system reliability, accommodate future uncertainty, and be cost-effective to implement.

The recommended approaches reflect the most effective and practical means of addressing the underlying system limitations while maintaining compliance with applicable planning criteria.

As all identified needs are expected to emerge in the near-term, this section focuses on solutions that can be implemented within the required timeframe while preserving flexibility to respond to future changes in system conditions.

7.1 Solution Assessment Framework

Potential solutions were developed by the TWG and assessed to address the electricity system needs identified in Section 6. The assessment considered a range of solution types, including:

- transmission reinforcements or reconfigurations;
- station-level capacity additions or upgrades;
- local generation resources; and
- operational and NWAs, where feasible.

Each solution was assessed against key considerations including:

- effectiveness in addressing the identified need and maintaining compliance with ORTAC, NERC, and NPCC criteria;
- timing and deliverability;
- flexibility and scalability, particularly where needs increase in magnitude over time;
- cost-effectiveness, including capital and lifecycle considerations;
- consistency with broader system plans, including provincial planning outlooks and planned reinforcements such as the Northeast Bulk Reinforcement Plan.

The assessment framework recognizes that different solution types may be more appropriate for different needs. As a result, solutions were evaluated and compared separately for station capacity needs and supply capacity needs, as described in the sections below.

7.2 Plan Options and Recommendations for Station Capacity Needs

This section describes the approach used to assess and address station capacity needs in the ELS region and presents the options considered for identified and potential needs.

Station capacity needs arise when forecast demand exceeds the capability of transformer stations to supply load. These needs are typically addressed through two types of solutions. Wires solutions increase station capacity through transmission and distribution system investments, such as replacing or adding transformers, expanding existing stations, or developing new station infrastructure where required. NWAs reduce net peak demand to remain within existing station capacity. These may include demand-side measures, DG, or other local supply resources. However, NWAs are not suitable for all station capacity needs and are generally more dependent on the magnitude, timing, and duration of the constraint.

As a result, NWAs are first screened to determine whether they are technically feasible and appropriate for a given need. This screening considers the characteristics of demand growth, the nature of the underlying limitation, and the ability of NWAs to reliably address the constraint.

7.2.1 Plan Options and Recommendations for Chapleau DS Station Capacity Need

As described in Section 6.2, no station capacity need has been identified at Chapleau DS under the Reference Scenario within the planning horizon.

Consistent with the regional planning approach, implementation of station capacity solutions is typically advanced when forecast demand indicates a need within the required project lead time. Where potential needs are identified in the longer term or under sensitivity scenarios, options are reviewed at a high level and monitored through future planning cycles rather than advanced immediately. Under the High Growth Scenario, a potential station capacity need may emerge in the late-2030s, driven primarily by increased peak demand. This scenario has been assessed to provide insight into how the system may evolve under higher growth conditions and to support longer-term planning considerations. To inform this assessment, a range of potential options was reviewed at a high level, including both network-based solutions and NWAs.

A wires-based option involving Chapleau DS2 (Chapleau Municipal Station) was reviewed at a high level. This option would involve converting the existing 115 kV/4 kV Chapleau DS2 station to operate at a 25 kV secondary voltage, consistent with Chapleau DS, and transferring customers to the 25 kV system. This conversion would require replacement of existing transformers and associated modifications to feeders, protection, and control systems.

However, this work is not considered a capacity expansion option. Chapleau DS2 is an aging station with obsolete voltage configuration and is expected to require refurbishment or replacement in the near future. The proposed conversion would allow for the retirement of the aging Chapleau DS2 assets and enable all customers in the area to be served at a standardized 25 kV voltage level in alignment with Hydro One Distribution practices.

While the conversion does not materially increase system capacity, it would provide operational and reliability benefits by standardizing voltage levels across the Chapleau area. This would improve system flexibility, including enhanced ability to back feed circuits and respond to contingencies.

As such, this initiative is best characterized as an asset renewal and system modernization activity rather than a capacity solution. It is noted here for context but is not considered a plan option to address station capacity needs.

NWAs were also considered at a high level. While certain options may be technically feasible, their applicability is generally limited by the scale, timing, and location of the potential need, as well as available connection capacity within the existing distribution system. As such, NWAs were not identified as primary solutions for this need but may be reconsidered in future planning cycles.

Given the absence of a station capacity need under the Reference Scenario, no actions are required at this time. Load growth and system conditions will be reviewed through ongoing TWG activities, and station capacity solutions will be advanced when forecast demand indicates a need within project lead time.

7.3 Solutions to Address Supply Capacity Needs

This section describes the approach used to assess and address supply capacity needs in the ELS region and presents the options considered for identified needs.

Supply capacity needs arise when there are limitations in the ability of the transmission system to deliver sufficient power to a defined area under normal or contingency conditions. These needs are typically associated with transmission supply interfaces, where the amount of load that can be served is determined by the transfer capability of the interface and the availability of supply resources within the area.

To address supply capacity needs, a range of solutions is considered. These may include transmission reinforcements to increase transfer capability, such as new lines or autotransformers, or the addition of voltage support equipment to improve system performance. In many cases, local supply resources and NWAs can also play a role, particularly where they can be effectively located and operated to support the affected area.

The preferred approach in each case reflects the solution, or combination of solutions, that most effectively addresses the underlying limitation while maintaining compliance with planning criteria and remaining practical to implement. Given that supply capacity needs often affect a broader area and multiple stations, solutions are assessed with consideration of their ability to provide reliable and flexible support under a range of operating conditions.

The supply capacity needs assessed in this section include:

- The Chapleau area supply capacity need associated with voltage limitations on the W2C supply path.
- The Algoma 115 kV interface supply capacity need, driven by thermal limitations and non-compliant load rejection.
- The Sault Ste. Marie 115 kV System interface supply capacity need, driven by voltage instability under certain planning conditions.

Solutions were assessed based on their ability to improve load meeting capability, address voltage or thermal limitations, reduce reliance on non-compliant remedial actions, and maintain system reliability under applicable contingency conditions.

7.3.1 Plan Options and Recommendations for Chapleau Area Supply Capacity Need

As described in Section 6.3.1, a supply capacity need has been identified in the Chapleau area, driven by post-contingency voltage limitations on the W2C supply path. This near-term need requires a solution to address the underlying voltage limitation and maintain system reliability.

A range of potential options was considered, including transmission-based solutions, local supply resources, and NWAs. The preferred approach is the implementation of localized static reactive power support in the Chapleau area. Providing localized reactive support would improve voltage stability, increase load meeting capability, and restore voltage support previously provided by local generation. This approach directly addresses the underlying voltage limitation and provides a durable solution under contingency conditions.

The use of static reactive support represents a cost-effective and appropriate solution for the identified need. The specific sizing, siting, and configuration of the required equipment will be determined through the RIP, based on detailed technical and economic assessment.

Other options were also assessed to support the evaluation. NWAs, including combinations of wind generation, battery energy storage, and demand-side measures, may provide partial and short-term mitigation, particularly during the initial years following need onset. However, their applicability is constrained by technical limits on the system, including limited connection capacity at the distribution and transmission level, as well as voltage performance constraints on the W2C supply path. These constraints restrict the amount of additional generation or demand reduction that can be effectively integrated without further upstream reinforcement. As a result, NWAs could only be deployed in sufficient quantity to manage the need in the early-2030s and are not capable of providing a durable, long-term solution.

Local gas-fired generation was also found to be technically feasible, as it could provide firm supply and reactive capability. However, it represents a higher cost and less direct approach to addressing a voltage-driven need and was not advanced as the preferred solution.

Demand-side measures, including additional eDSM, may provide modest near-term load relief but are similarly insufficient to resolve the underlying constraint or provide sustained mitigation as demand increases.

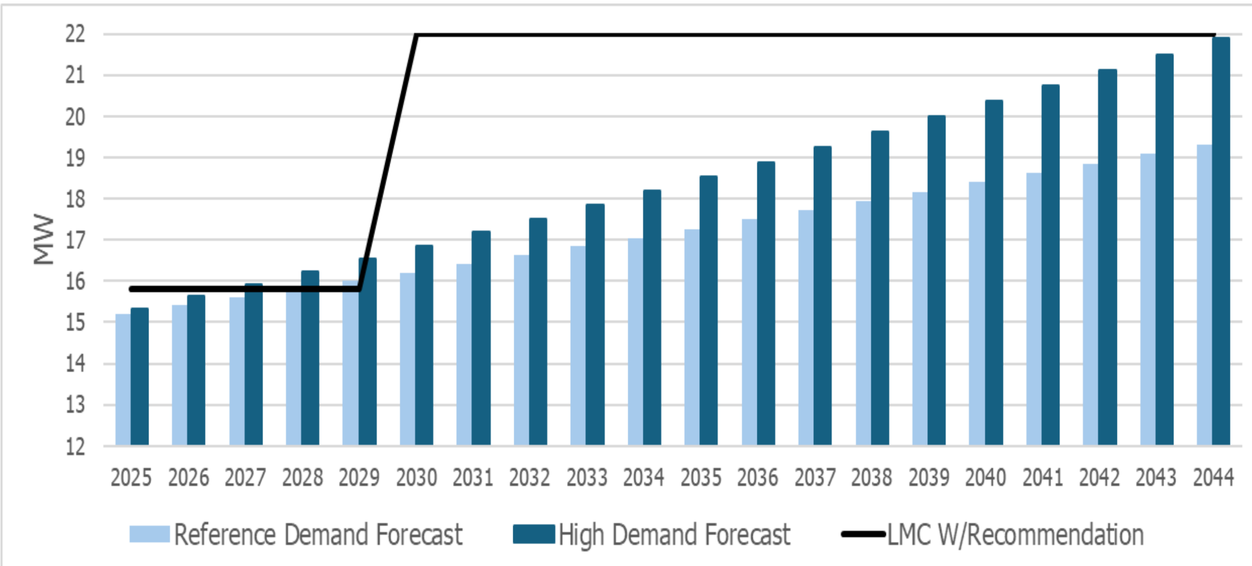
Accordingly, the recommended approach is to implement localized static reactive power support in the Chapleau area. Supplementary measures may be considered to support system needs during initial implementation; however, a permanent voltage support solution is required to address the identified supply capacity limitation. The detailed design, sizing, siting, and implementation timing of this solution will be confirmed through a RIP led by Hydro One.

During the preparation of this IRRP, Hydro One Distribution identified a potential project involving the addition of a new transformer at Chapleau DS. This project is currently in the early scoping phase and remains subject to further assessment and confirmation.

As this information became available late in the study process, its potential impact on system capacity and voltage performance in the Chapleau area has not been assessed. This potential development is separate from the 4 kV to 25 kV conversion initiative in the Chapleau area. While it may influence future system needs, it does not change the recommended approach at this time.

The TWG will continue to monitor this development and assess its implications as part of the RIP phase or future regional planning cycles.

Figure 17 | Chapleau Area Need with Recommendation



7.3.2 Plan Options and Recommendation for Algoma Area Supply Capacity Need

As described in Section 6.3.2, the Algoma 115 kV interface supply capacity limitation is driven by thermal constraints on the transmission system under contingency conditions. Under these conditions, post-contingency loading on the remaining transmission circuits can exceed applicable emergency thermal ratings, requiring corrective action to maintain system reliability.

This condition is currently managed through a RAS, which mitigates overloads by shedding load within the Algoma area following specific contingency events. Under planning criteria, the use of RAS is acceptable provided that the magnitude of load rejection remains within allowable limits. However, the existing scheme may result in load rejection in excess of the thresholds specified under ORTAC, resulting in non-compliance with planning criteria.

The preferred approach is to enhance the existing RAS to improve its selectivity and operational performance. Enhancements would focus on enabling more granular load shedding, allowing the system to reject only the minimum amount of load required to mitigate post-contingency thermal violations. This directly addresses the source of non-compliance by reducing the magnitude of load interruption while maintaining the effectiveness of the protection scheme.

This approach is appropriate given that the underlying limitation is driven by thermal performance under specific contingency conditions rather than sustained peak demand. By improving the performance of an existing system protection mechanism, it provides a targeted and efficient solution and avoids the need for more capital-intensive transmission reinforcements. It also maintains system operability under contingency conditions while aligning with applicable planning criteria.

Due to the lead time required to design, implement, and commission RAS enhancements, including engineering design, protection system upgrades, testing, and co-ordination with system operations, an interim measure is required to ensure continued reliable operation of the system. In the near term, the TWG will work with impacted customers to establish a load rejection exemption framework. Under this approach, customers would acknowledge and accept load interruption levels exceeding standard planning criteria under defined contingency conditions, providing a temporary and transparent mechanism to manage system risk while longer-term improvements are implemented.

Transmission reinforcement options were also assessed, including uprating the Algoma transmission circuits to increase transfer capability into the area. To meet reliability requirements under both single- and double-contingency conditions, co-ordinated uprating of Algoma No.1 and Algoma No.3 would be required. While technically feasible, this approach would significantly increase project scope, cost, and constructability risk, while providing a less targeted solution to a contingency-driven limitation.

As demand in the Algoma area evolves beyond the conditions assessed in this IRRP, transmission reinforcement options may be revisited in future planning cycles or TWG reviews to confirm whether additional infrastructure is warranted.

Accordingly, the recommended approach is a staged solution consisting of an interim load rejection arrangement followed by targeted enhancements to the existing RAS to restore compliance with planning criteria.

7.3.3 Plan Options and Recommendations for Sault Ste. Marie Supply Capacity Need

As described in Section 6.3.3, the Sault Ste. Marie 115 kV system interface supply capacity need is driven by voltage instability following the sequential loss of both autotransformers at Third Line TS. Under this condition, the remaining 115 kV network is unable to maintain acceptable voltage levels and reliably serve load, and thermal overloads are also observed on the K3G transmission section. This need is expected to emerge in the near term and requires a solution to maintain system reliability.

A range of potential options was considered, including transmission reinforcements, local supply resources, and NWAs. The recommended action is to pursue a cost-effective supply solution with performance characteristics aligned with the identified reliability risk. The capability of the resource must match the characteristics of the need, requiring a resource that is dispatchable when needed after a contingency, and capable of sustained operation for the duration of the contingency condition. This performance-based framing preserves flexibility with respect to the specific technology or acquisition approach, supports transparency with communities, and allows the need to be addressed, subject to demonstrated deliverability and applicable municipal and provincial siting requirements.

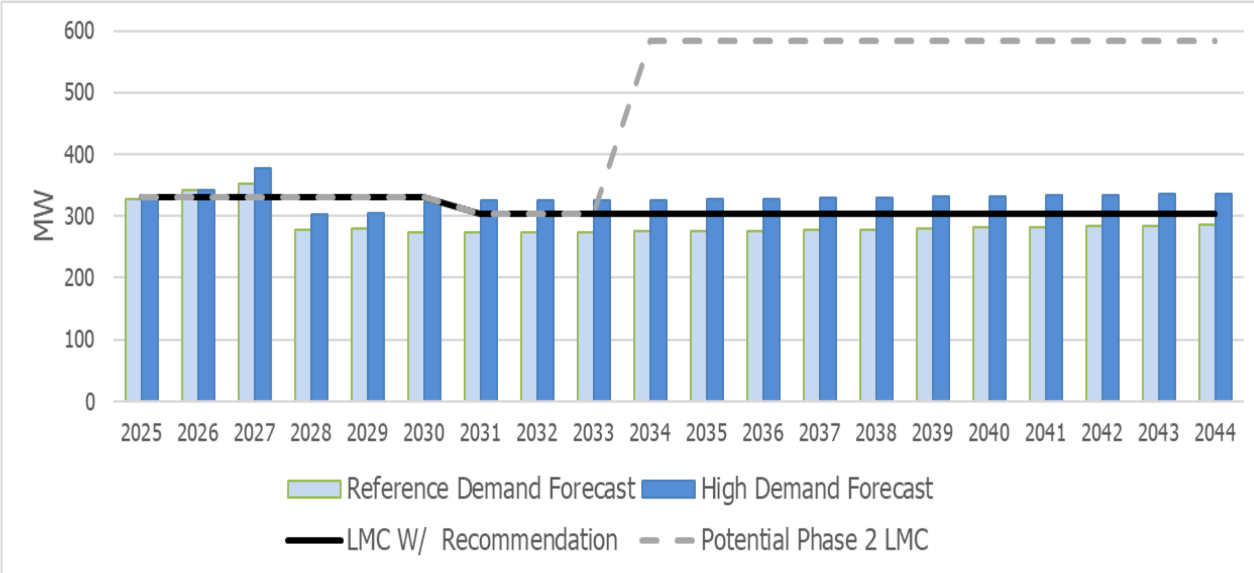
The ability to implement new supply resources in the Sault Ste. Marie area is currently constrained by system conditions, including limits on connection capacity and restrictions on the integration of certain resource types. These constraints limit the amount and type of resources that can be connected and reliably contribute to system needs and will need to be considered in the design and implementation of any solution.

Other NWAs were also assessed. Resource combinations such as wind generation, battery energy storage, and demand-side measures were found to be technically constrained in the area and are not capable of providing the firm, dispatchable, and sustained performance required to address the identified reliability need. Demand-side measures alone are similarly insufficient, as they do not provide the level of firm capacity or reactive support required under contingency conditions. Load transfer options were also assessed and found to be infeasible due to network limitations and the absence of sufficient alternate supply paths.

A transmission-based solution involving the addition of a third autotransformer at Third Line TS was also assessed as a longer-term option. This approach would increase system redundancy, improve voltage performance, and fully eliminate the identified limitation; however, it involves higher cost and longer lead times. In contrast, a supply resource with the required performance characteristics provides ongoing system value by contributing energy and capacity to the system, while also addressing the local transmission reliability risk under contingency conditions. As a result, a performance-based supply solution represents a more cost-effective and flexible approach in the near term. The addition of a third autotransformer at Third Line TS is therefore considered a potential future consideration (Phase 2) reinforcement, the timing of which is not predetermined and would depend on future demand growth and system conditions. As demand and system conditions evolve, transmission reinforcement options may be revisited through future planning cycles and TWG reviews to confirm whether a wires-based solution is required. Supply constraints and congestion in the region currently limit inverter-based generation integration. These constraints limit the ability of certain resource types to address system needs, even when they may be otherwise cost effective. During outage conditions, congestion also results in curtailment of low-cost generation options, which add increased costs to the market. A review of demand and supply conditions in the 2028 to 2029 timeframe is recommended to confirm timing and identify the appropriate long-term approach.

Accordingly, the recommended approach is to pursue a cost-effective supply solution that meets the defined dispatchability, duration, and voltage support requirements to address the identified supply capacity need in the near term.

Figure 18 | Sault Ste. Marie Need with Recommendation



For illustrative purposes, the potential Phase 2 reinforcement (addition of a third autotransformer at Third Line TS) is reflected in the LMC projection in the mid-2030s to demonstrate its impact on system capability; however, the timing of this reinforcement is not predetermined and will depend on future system conditions and demand growth.

7.4 Summary of Recommended Actions and Next Steps

The TWG recommends the actions summarized in Table 6 below to meet needs identified in the ELS region IRRP.

Table 6 | Summary of Recommendations for ELS Region

Action	Reinforcement Type	Needs Addressed	Implementation	Expected In-Service	High Level Planning Cost Estimate ($)
ELS region monitoring	Planning/ monitoring	Preserves long-term flexibility and informs future infrastructure-based solutions	ELS TWG	Ongoing	-
Chapleau reactive power support	Transmission-side static reactive power support, with demand side measures serving as	Address voltage-limited supply capacity constraints in the Chapleau Area	Hydro One (reactive support); IESO (eDSM)	Near-Term	~ 8M

Action	Reinforcement Type	Needs Addressed	Implementation	Expected In-Service	High Level Planning Cost Estimate ($)
	short-term supplement				
Address Algoma 115 kV interface supply capacity need	Enhance existing RAS to support more flexible control actions; load rejection exemption framework	Mitigates contingency-driven thermal limitation at the Algoma 115 kV interface	Hydro One	Near-Term (interim); TBD (RAS)	~5M
Address Sault Ste. Marie 115 kV interface supply capacity need	Performance based supply solution with demand side measures	Address voltage instability limitations in the Sault Ste. Marie 115 kV area	IESO (lead); TWG support	TBD	-[7]
Address Sault Ste. Marie 115 kV interface supply capacity need - Long-Term	Ongoing planning assessment through TWG and planning cycles	Ensure long-term supply adequacy and determine need for wires solution (i.e. new autotransformer) at Third Line TS	ELS TWG	Ongoing/ Trigger-based	-

[7] Costs for a supply resource in the region would be offset by system benefits that would be realized by any resource

8. Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and perspectives of the public, which for these purposes, refers to market participants, municipalities, stakeholders, communities, Indigenous communities, customers and the general public, to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken to date for the ELS IRRP.

8.1 Engagement Principles

The IESO's External Relations Engagement Framework and is built on a series of key principles that respond to the needs of the electricity sector, communities and the broader economy. These principles ensure that diverse and unique perspectives are valued in the IESO's processes and decision-making. We are committed to engaging with purpose to foster trust and build understanding.

Figure 19 | The IESO's Engagement Principles

8.2 Engagement Tactics

To ensure that the IRRP reflects the needs of market participants, municipalities, stakeholders, communities, Indigenous communities, customers and the general public, engagement tactics involved:

- Leveraging the ELS engagement webpage to share information including engagement opportunities, meeting materials, input received and the IESO's response to feedback;

- Leading targeted discussions with key Indigenous communities and municipal staff to help inform the engagement approach for this planning cycle;
- Hosting public webinars at major junctions in the plan development to share plan details, understand feedback and answer questions, and;
- Providing written updates through email and IESO's weekly Bulletin updates to all subscribers.

8.3 Engagement Approach

Four public engagement webinars were held at major stages during the Scoping Assessment and IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan.

Public engagement webinars were attended by municipal staff, community representatives, businesses, Indigenous communities, and other interested parties and written feedback was collected following a comment period after each webinar. The four stages of engagement at which input was invited were:

1. The draft scoping outcome assessment report to share the planning approach before delving into the full IRRP study;
2. The draft engagement plan and electricity demand forecast to set the foundation of this planning work;
3. The electricity needs for the region and an overview of wired solutions and NWAs that could meet the needs; and
4. The detailed analysis of all feasible wired solutions and NWAs and draft IRRP recommendations.

Comments received during the development of the IRRP primarily focused on:

- Accounting for growth and economic development projects across the region;
- Ensuring climate impacts are accounted for throughout the development of the IRRP, and;
- Exploring alternative solutions, such as NWAs, to meeting the area's electricity needs.

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

Scoping Assessment

The ELS region was anticipated to experience significant electricity demand growth given earlier regional and bulk plans in this area. Additional local needs were identified in the Needs Assessment and shared during this milestone, confirming the approach to proceed with an IRRP. Email communications were sent to all subscribers of the ELS region, including municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and encourage participation on the ELS Scoping Assessment report finalization. A public webinar was held in December 2024 to provide an overview of the regional electricity planning process, the draft report and proposed approach.

Feedback received during this milestone encouraged the IESO to consider co-ordination between the electric and gas sectors to help optimize the energy systems in ELS and to consider expanding participation in the TWG. The IESO welcomed any additional information and meetings to help inform the study as it progresses. The final Scoping Assessment report was posted in January 2025, identifying the need for a co-ordinated regional planning approach for the ELS region.

Demand Forecast

Following finalizing the Scoping Assessment, the TWG began the development of region’s electricity demand forecast. IRRP recommendations are typically driven by the Reference Demand Forecast, which includes firm loads (current and planned), organic growth, residential, electrification and energy plans, and industrial growth. A High Growth Scenario was also developed to capture growth and trends that are less certain such as large-scale customer connections.

To achieve this, the IESO engaged with all municipalities to understand any key loads to engage, as well as with transmission-connected loads, to understand their growth plans and ensure it was captured in the draft forecasts. The draft forecasts were shared through the launch of a broader public engagement initiative. Communications to IESO subscribers of the ELS region ensured all interested parties were made aware of the opportunity for input.

During this milestone, key information shared was that the electricity demand is growing significantly with demand estimated to grow by 112%. The primary drivers of growth are electrification initiatives, including Algoma Steel’s EAF transformation project. The reference forecast was ultimately used to drive recommended solutions, however the TWG will identify options for long-term electricity needs and high-growth scenarios, refining these options in future planning cycles and activating them as growth occurs.

Based on the feedback through this engagement initiative, a key priority was to ensure the IRRP considered climate impacts into the demand forecast and incorporated resiliency into recommended actions. The TWG ensures the forecast reflects extreme weather conditions in various scenarios, which includes the system’s ability to respond to disturbances, and committed to ongoing discussions about resiliency throughout plan development. Additionally, feedback was centred around ensuring strong justification for new or upgraded infrastructure developments are provided. The TWG committed to evaluating wired solutions and NWAs and sharing the analysis as planning work advances.

Electricity Needs and Options Identification

During this milestone, the TWG initially identified a station capacity need and three supply capacity needs, each with unique system challenges. During targeted municipal discussions and the public engagement webinar, the TWG shared the types of options that are considered as part of the regional planning process to meet needs. The examples illustrated the range of options typically considered, with further analysis underway to determine which solutions would be most appropriate based on system needs and constraints.

Feedback at this stage of the engagement sought to further clarify the options analysis stage of the IRRP, particularly if NWAs would be considered and if options would be advanced on high demand projections. The TWG committed to sharing a detailed options analysis in the upcoming milestone. Additionally, feedback received urged to consider forward-looking climate projections. The TWG acknowledged the importance of accounting for temperature trends in the forecasting development and shared information about how extreme weather is included in this process.

Options Analysis and Draft Recommendations

During this milestone, the TWG shared the options analysis for all feasible wired solutions and NWAs and the draft recommendations through targeted municipal discussions and a public engagement webinar. Since the last webinar, the previously identified station capacity need at Chapleau DS was resolved based on updated information showing sufficient station capacity, leaving three supply capacity needs remaining. To meet the needs, the Technical Working Group drafted the following recommendations:

- Install a reactive device (capacitor) to improve supply capacity and voltage performance for the Chapleau area, supported by electricity demand-side management as an interim measure.
- Pursue generation options at the Sault Ste. Marie 115kV interface and monitor the load growth in the area to determine whether an additional autotransformer is required in the future.
- Obtain an operational measure exemption at the Algoma 115kV interface as enhancements to the existing RAS is implemented.
- Monitor load growth and system performance to identify timing on advancing additional system improvements if needed to maintain compliance with reliability criteria.

Feedback at this stage of the engagement sought to further clarify if deliverability constraints will impact the generation recommendation and linkages to other ongoing work in the region.

8.4 Involving Municipalities in the Plan

Throughout the IRRP engagement, valuable feedback was received from municipalities and incorporated into the final IRRP including:

- Enhancing webinar materials to share technical updates in a transparent and digestible manner;
- Including the latest energy plans on electrification, HVAC systems and electric vehicles, and transmission-connected customers in and around the Sault Ste. Marie area; and
- Providing details on linkages with ongoing and previous regional and bulk plans, including the 2022 Northeast Bulk Plan recommendations and ongoing Sudbury/Algoma regional plan.

8.5 Engaging with Indigenous Communities

The IESO remains committed to an ongoing, effective dialogue with Indigenous communities to help shape long-term planning across Ontario. This engagement was part of a broader commitment to fostering respectful relationships, ensuring transparency, and supporting informed participation in integrated regional electricity system planning. Throughout the development of this plan, the IESO's engagement with Indigenous communities included inviting Indigenous communities to participate in online information sessions held on December 4, 2024, July 9, 2025, December 11, 2025 and June 4, 2026, as well as Indigenous-focused meetings that were held those same days, in order to provide additional opportunities to ask questions and provide input.

To share information about the planning activities and invite participation in the engagement process, outreach was made to the following Indigenous communities:

- Batchewana First Nation
- Brunswick House First Nation
- Chapleau Cree First Nation
- Chapleau Ojibwe First Nation
- Garden River First Nation
- Michipicoten First Nation
- Missanabie Cree First Nation
- Mississauga First Nation
- Serpent River First Nation
- Thessalon First Nation
- Métis Nation of Ontario
- Bar River Métis
- Red Sky Métis Independent Nation

Detailed non-confidential feedback submitted to the IESO and the IESO's responses can be viewed on the East Lake Superior Planning Engagement webpage. At a high level, the IESO received the following feedback:

- M'Chigeeng First Nation requested more detailed data from the IESO on Algoma Steel Foundry electrification to better understand regional impacts and reduce uncertainty. They emphasized prioritizing Distributed Energy Resources (DERs)—including wind, solar, hydro, and battery storage—as the primary solution to address regional supply needs. They expressed concern that demand-side management (eDSM) may not effectively reduce consumption given anticipated rapid load growth. The Nation also suggested the IESO explore a new transmission line from the Sudbury/Algoma region, supported by DERs along the north shore, to enable future distribution-level load transfers—similar to proposed lines in the Northeast (Hanmer TS → Mississagi TS → Third Line TS).
- Batchewana First Nation did not raise concerns but requested to remain engaged and informed, highlighting the importance of any infrastructure development within their traditional territory.

9. Conclusion and Next Steps

This IRRP outlines a needs-based, staged approach to meeting electricity system needs and maintaining a reliable and cost-effective electricity system in the ELS region over the planning horizon. The plan was developed through collaboration among the IESO, the ELS TWG, and regional partners, informed by detailed technical analysis and engagement with communities and stakeholders.

The needs assessment identified a limited number of near-term electricity system needs, primarily related to supply capacity limitations driven by voltage and thermal performance under applicable contingency conditions. These needs are largely attributable to existing system configuration, operational constraints, and planning criteria requirements rather than widespread forecast demand growth. With the inclusion of the Northeast Bulk Reinforcement, no new or distinct medium- or long-term regional electricity needs were identified over the planning horizon.

A broad range of potential solutions was considered to address the identified needs, including transmission and distribution reinforcements, local generation, demand-side resources, operational measures, and NWAs. Preferred approaches were selected based on their ability to address the underlying drivers of each need, their technical feasibility and deliverability within the required timeframe, and their relative cost, risk and alignment with system needs.

For the Chapleau area, the preferred approach is the implementation of localized transmission-side reactive power support to address voltage-limited supply capacity on the W2C supply path. This solution directly addresses the root cause of the constraint and provides effective and durable voltage support. Demand-side resources and DERs, including eDSM, were identified as having the potential to provide modest, short-term relief but only as a supplementary measure and not as a standalone solution.

For the Algoma 115 kV interface, the preferred approach is a staged solution consisting of interim customer arrangements for controlled load interruption, followed by enhancements to the existing RAS. This reflects the industrial nature of the load served and the low-frequency, contingency-driven characteristics of the limitation. This approach provides a proportionate and practical means of maintaining compliance with planning criteria while avoiding significant infrastructure investment under stable demand conditions.

For the Sault Ste. Marie 115 kV system interface, the preferred approach is to pursue a cost-effective supply solution with performance characteristics aligned with the identified reliability risk. The capability of the resource must match the characteristics of the need, requiring a resource that is dispatchable when needed after a contingency and capable of sustained operation for the duration of the contingency condition. This performance-based framing preserves flexibility with respect to the specific technology or acquisition approach and allows the need to be addressed in a targeted and cost-effective manner, while delivering broader system value through energy and capacity contributions under normal operating conditions.

Future infrastructure-based options, including the addition of a third autotransformer at Third Line, have been identified to preserve optionality and may be reconsidered in subsequent planning cycles should there be an increase in load, changes in system conditions, or evolving reliability expectations that warrant a permanent reinforcement.

Engagement undertaken throughout the development of this IRRP supported transparency and provided valuable input to inform planning assumptions and option screening. Engagement will continue beyond the publication of this plan as recommended actions progress and as future regional planning activities are undertaken.

9.1 Path Forward and Ongoing Monitoring

Consistent with the approach taken in previous ELS IRRPs, this plan establishes a clear path forward while maintaining flexibility to respond to evolving system conditions.

In the near-term, next steps include:

- Advancing the preferred solutions identified in this IRRP through appropriate implementation mechanisms, including RIPs and contractual arrangements, as applicable;
- Continued co-ordination among the IESO, transmitters, and LDCs to support timely implementation; and
- Ongoing monitoring of system performance, load levels, and operating conditions through the TWG activities to validate planning assumptions and confirm implementation timing.

Over the longer-term, the IESO and regional planning partners will continue to monitor:

- Changes in load levels, electrification trends, and local development activity;
- The performance and effectiveness of implemented solutions; and
- Emerging risks or constraints that may give rise to new or evolving electricity system needs.

Should system conditions materially change, the TWG will review to confirm timing and identify appropriate actions to maintain system reliability.

Overall, this IRRP provides a clear, proportionate, and flexible plan to address the identified electricity system needs of the ELS region, balancing near-term reliability requirements with longer-term adaptability and prudent investment.

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