
East Lake Superior Region Integrated Regional Resource Plan Appendices

October 1, 2026



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List of Acronyms

API	Algoma Power Inc.
APO	Annual Planning Outlook
APS	Achievable Potential Study
ATB	Annual Technology Baseline
BESS	Battery Energy Storage System
CAD	Canadian Dollar
CapEx	Capital Expenditure
CTS	Customer Transformer Station
DER	Distributed Energy Resource
DG	Distributed Generation
DS	Distributed Station
EA	Economic Assessment
EAF	Electric Arc Furnace
EE	Energy Efficiency
ELS	East Lake Superior
eDSM	Electricity Demand Side Management
EV	Electric Vehicle
EWTE	East-West Tie East
EWTW	East-West Tie West
FOM	Fixed Operating and Maintenance
GDP	Gross Domestic Product
GLP	Great Lakes Power
G/R	Generation Rejection
IBR	Inverter-Based Resource
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
L/R	Load Rejection
LSP	Lake Superior Power
LTE	Long-Term Emergency Rating
MTS	Municipal Transformer Station
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NPCC	Northeast Power Coordinating Council
NPV	Net Present Value
NWA	Non-Wires Alternative
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
PUC	Public Utilities Commission
RAS	Remedial Action Scheme

RIP	Regional Infrastructure Plan
SCADA	Supervisory Control and Data Acquisition
SCGT	Simple Cycle Gas Turbine
STE	Short-Term Emergency Rating
TS	Transformer Station
TWG	Technical Working Group
Tx	Transmission
UFLS	Under-Frequency Load Shedding
UVLS	Under-Voltage Load Shedding

Appendix A. Overview of the Regional Planning Process

A.1 The Regional Planning Process

In Ontario, meeting the electricity needs of customers at a regional level is achieved through regional planning. This comprehensive process starts with an assessment of the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium and long term and results in the development of a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs and recommend actions.

Regional planning has been conducted on an as-needed basis in Ontario for many years. Most recently, planning activities to address regional electricity needs were the responsibility of the former Ontario Power Authority (OPA), now the Independent Electricity System Operator (IESO), which conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Ontario Energy Board (OEB) convened a Planning Process Working Group (PPWG) to develop a more structured, transparent and systematic regional planning process. This group was composed of electricity agencies, utilities and other stakeholders. In May 2013, the PPWG released its report to the OEB (PPWG Report), setting out the new regional planning process. Twenty one electricity planning regions were identified in the PPWG Report and a phased schedule for completion of regional plans was outlined.¹ The OEB endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013 and to the former OPA's licence in October 2013. The licence changes required it to lead two out of four phases of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence became the responsibility of the IESO.

The regional planning process begins with a Needs Assessment process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO conducts a Scoping Assessment to determine what type of planning is required for a region. A Scoping Assessment explores the need for a comprehensive IRRP, which considers conservation, generation, transmission and distribution solutions, or whether a more limited “wires” solution is the preferable option, in which case a transmission- and distribution-focused Regional Infrastructure Plan (RIP) can be undertaken instead. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the needs assessment process

¹ http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

and a preliminary terms of reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If an RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a two-week public comment period prior to finalization.

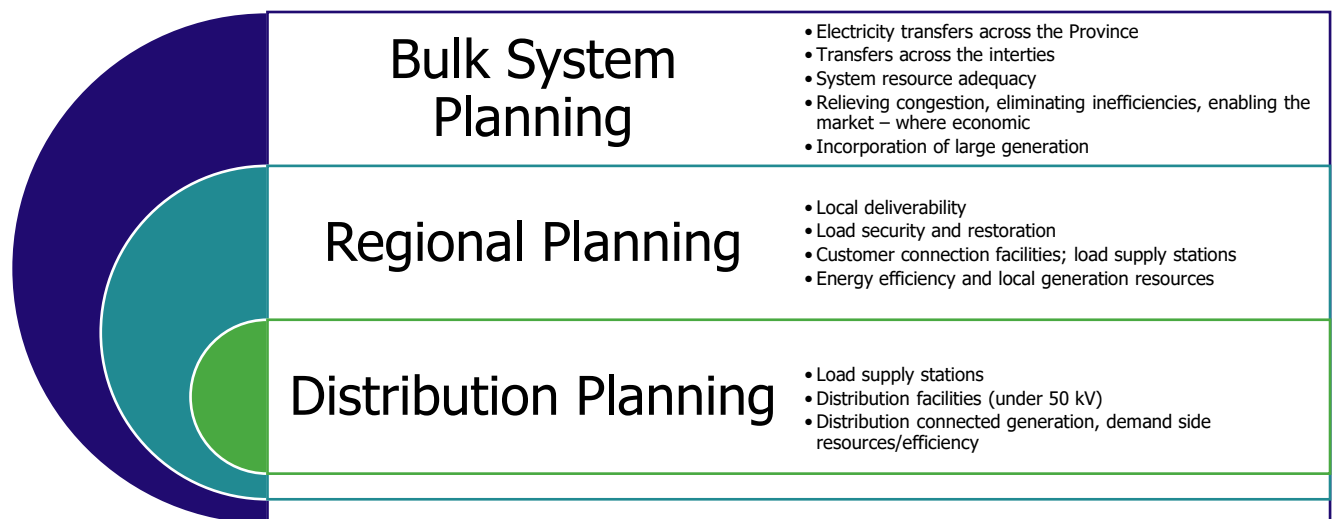
The final Needs Assessment Reports, Scoping Assessment Outcome Reports, IRRPs and RIPs are posted on the IESO's and the relevant transmitter's web sites and may be referenced and submitted to the OEB as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis community councils for planning and for conservation and energy management purposes. They are also a useful source of information for individual large customers that may be involved in the region and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning undertaken in Ontario. As shown in Figure 1, three levels of electricity system planning are carried out in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

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

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

Figure 1 | Levels of Electricity System Planning



By recognizing the linkages with bulk and distribution system planning and coordinating the multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan into perspective. Furthermore, in avoiding piecemeal planning and asset duplication, regional planning optimizes ratepayer interests, allowing them to be represented along with the interests of LDC ratepayers and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process and by making plans available to the public.

Appendix B. Demand Forecast

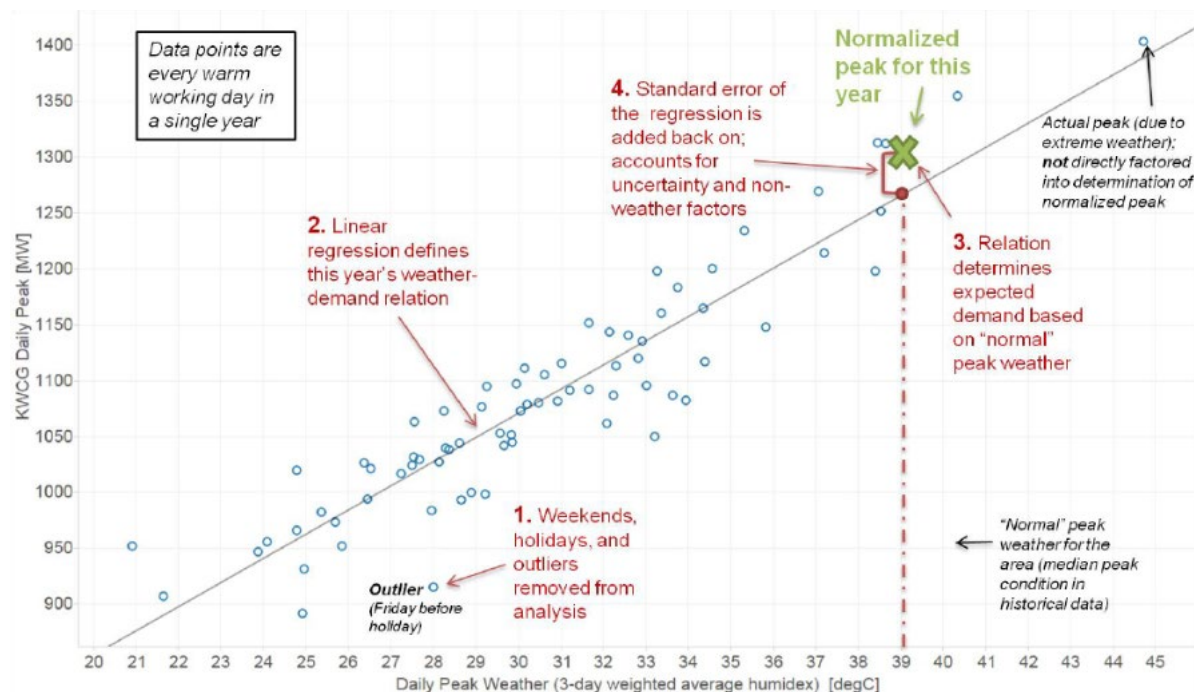
The methods utilized to create the demand forecast for the East Lake Superior (ELS) Region are detailed in this Appendix. The following sections describe the methods used by the IESO to develop the forecast starting points as well as the approaches used by each LDCs to forecast the demand in their respective service areas. The forecast base year and starting points were provided by the IESO and were used by the participating LDCs to estimate their electricity demand.

B.1 Developing Forecast Starting Point

In developing the starting point for the forecast, historical demand was first weather-normalized and adjusted to reflect the median peak weather conditions. This was done for each transformer station in the area for all historical years.

Median (“normal”) peak weather condition generally refers to the expected peak demand under the most likely, or 50th percentile, weather conditions. This means that, in any given year, there is an estimated 50% chance that the actual peak demand will either exceed or be lower than the median (“normal”) peak. An example for determining the weather-normalized peak can be seen in Figure 2. Note that this example was developed for a different region.

Figure 2 | Developing the Weather-Normalized Peak



Then, the impact of Distributed Generation was added to the weather-corrected yearly peaks where the most recent year (2024) was used as a starting point. This data was provided to all the LDCs to begin their 20-year demand forecasts which was developed using their own preferred methodologies, described further in Appendix B.2.

In summary, the following general steps were conducted to develop a starting point for the ELS region demand forecast:

- Gathered historical non-coincident peak demand data in the region for the past 5 years, i.e. 2020-2024, for each station.
- Weather corrected historical demand data on a yearly and station basis to reflect median peak weather conditions.
- Added historical output from Distributed Generation at the time of peak back to the historical demand data for each year and each station (as DG output is subtracted from the gross forecast²).
- Used the most recent weather-corrected gross peak load as the starting point.

Then, the 20-year median peak demand forecasts are provided to the IESO by the LDCs which are consequently adjusted to reflect the impact of extreme weather conditions on electricity demand. The extreme weather adjustment factors used in the ELS IRRP are calculated per IESO's methodology for modelling extreme weather conditions, which identifies the correlation between weather and demand for a given region in a given timeframe.

In general, assessing the reliability of the electricity system infrastructure often necessitate the use of extreme weather demand forecasts, or, expected demand under the coldest weather conditions (in the case of ELS, which is a winter peaking region) that can possibly occur. Peaks that occur during extreme weather, such as winter polar vortexes, are generally when the electric power system is most stressed.

B.2 LDC Forecast Methodologies

The methodologies used to develop the 20-year demand forecasts are described in this section. Each participating LDC use their own preferred approach. These LDCs include:

- PUC Distribution Inc.
- Algoma Power Inc.
- Hydro One Networks Distribution

² A gross forecast means that existing and new DG and new eDSM savings are not accounted for in the forecast. Once DG and eDSM are accounted for, they will reduce the gross forecast to produce a net demand forecast; the forecasted demand to be experienced by the electricity system infrastructure.

B.2.1 PUC Distribution Inc.

B.2.1.1 Overview

The load forecast methodology employed by PUC Distribution Inc. and PUC Transmission LP provides projections of future electricity demand within our service territory. This methodology supports operational planning, system reliability and infrastructure investment decisions. It is primarily based on historical load data summer and winter peaks and is augmented by known electrification trends and planning inputs from municipal energy projects.

B.2.1.2 Data Sources

The forecasting process uses historical electricity consumption data for PUC Distribution Inc. collected at hourly intervals over the past 5 years as well as known electrification plans and projects for both PUC Distribution Inc. and PUC Transmission LP. Sources include:

- Internal SCADA systems and smart meter data.
- System-level demand records aligned with IESO revenue metering standards.
- Municipal and regional planning documents, including the City of Sault Ste. Marie's Community Energy Plan.
- Known electrification projects anticipated within our service territory.

B.2.1.3 Methodology

Data Aggregation and Cleaning

- Peak summer and winter load data is aggregated and checked for completeness and accuracy.
- Anomalies are corrected using interpolation or are excluded from averages.

Forecasting Technique

- Historical peak summer and winter load was gathered and plotted to establish a baseline and a trend line of the summer and winter peaks is continued for the forecasted years.

Adjustment Factors

- Electrification Adjustments: The forecast assumes low electrification growth, consistent with current trends and observed uptake rates in our service area. PUC assumed a 1-1.5% per year increase.
- Planned Electrification: Specific electrification initiatives outlined in the City's Community Energy Plan (e.g., targeted building retrofits, municipal fleet electrification, district energy integration) are layered onto the forecast where applicable.

- Industrial Electrification and Growth: Known industrial electrification projects of existing businesses in our service territory have been added to the forecast. Anticipated new industrial customers have also been added to the forecast with the understanding that the IESO will apply a sensitivity analysis to these potential customers.

Forecast Use and Reporting

- They are used to inform capacity planning, grid operations, demand response coordination and alignment with IESO planning processes.

B.2.1.4 Limitations

This method is grounded in historical consumption behavior and assumes relatively stable future patterns, modified for known electrification plans. While appropriate for near-term forecasting, it may not fully capture in detail disruptive changes such as rapid EV adoption, widespread electrification of heating, or behind-the-meter generation. Future iterations may incorporate scenario-based modeling or machine learning techniques to better accommodate dynamic trends.

B.2.2 Algoma Power Inc.

B.2.2.1 Overview

Load growth is primarily attributed to electric vehicles (EVs), residential household electrification, agricultural greenhouses, mining expansion, steel producer electrification in northern Ontario and continued residential sector growth. The transportation sector demand outlook has the most significant change with EV charging as the primary driving force behind this growth. Algoma Power Inc. (API) has aligned its forecasted annual planning outlook with the federal government targets on zero-emissions vehicle sales targets.

Geographically, API is responsible for one of the largest electrical distribution service territories in the province, spanning from Thessalon to Wawa. A large portion of Trans-Canada Highway is routed through this service territory and as such it is reasonable to expect there will be a need for improved and increased charging capacity in the future. The load growth includes future adoption of EV charging stations along the major highway corridors and small towns where existing gas stations reside to accommodate EV travelers.

B.2.2.2 Data Source

The forecasting estimations were analyzed using previous 5-year historical peak electrical consumption trends in the summer and winter for each transmission connected station.

B.2.2.3 Methodology

Using previous 5-year data trend, the following methodology was applied for estimating general load growth and growth in the locations where EV penetration is practical as discussed above:

- 20% accumulative general load growth (1.84%/annum over 10 years) plus 10% EV penetration rate.

B.2.3 Hydro One Networks Distribution

Hydro One Distribution services the areas of East Lake Superior (ELS) region that are not serviced by other LDCs. It supplies power through Chapleau stations included in the study area.

- Hydro One Distribution used both econometric and end-use forecasting to develop the 20-year load forecast provided to the IESO.
- A baseline forecast (MW station peak in the base year) was developed, taking into account such factors as normal operating conditions, coincident peak loading and extreme weather conditions.
- For the ELS IRRP forecast, Hydro One Distribution used the weather corrected peak demand levels for the stations serving Hydro One customers.
- From the established baseline year, a growth rate (%) was applied to station demand levels to provide forecast values, at each station, within the study timeframe.
- Assumptions included in the growth rate can be related to such factors as: Ontario GDP growth rate, housing statistics, the intensification of urban developments (i.e., MW per sq. ft); and electrification trends (e.g., more vehicles switching from gas to electrical vehicles).
- Where possible, detailed information about load growth, based on local knowledge and or municipal/provincial plans, was used to augment the forecast values within the study period.

B.3 Electricity Demand Side Management (eDSM) Assumptions

Electricity Demand Side Management (eDSM) initiatives help lower electricity demand. Their effects are grouped into two main categories: Building Codes & Equipment Standards and eDSM Programs. The assumptions used for the ELS IRRP forecast are consistent with the eDSM assumptions in the IESO's 2024 Annual Planning Outlook. The savings for each category were estimated according to the forecast residential, commercial and industrial gross demand. A top-down approach was used to calculate peak demand savings, starting from the provincial level, then moving to the Northeast transmission zone and finally allocating them to the ELS region.

This section describes the process and methodology used to estimate eDSM savings for the ELS region and provides more detail on how the savings for the two categories were developed.

Ontario building codes and equipment standards set minimum efficiency levels through regulations and are projected to improve and further contribute to demand reduction in the future. To estimate the impact on the study region, the associated peak demand savings for codes and standards by sector were estimated for the Northeast zone and compared with the gross peak demand forecast for the zone. From this comparison, annual peak reduction ratios were developed for the purpose of allocating the associated savings to each station in the region. The analyses were done for winter and summer separately and seasonal peak reduction ratios were estimated.

First, winter peak demand savings were estimated from winter gross demand forecast. New peak demand savings from codes and standards were estimated from 2025 to 2044. The residential winter peak reduction ratios of each year were applied to the forecasted residential winter peak demand at each station to develop an estimate of winter peak demand impacts from codes and standards.

The process was repeated for the summer peak demand forecasts.

In addition to codes and standards, the delivery of DSM programs reduces electricity demand. The impact of existing and planned eDSM programs were analyzed, which include the 2021-2024 eDSM Framework, the existing federal programs and the assumed continuation of provincial programs beyond 2024 at savings levels consistent with the current framework adjusted for gross demand growth (note program continuation has been confirmed with the IESO's receipt of a government mandate for the 2025-2036 eDSM Framework). A top-down approach was used to estimate the peak demand reduction due to the delivery of these programs from the province to the Northeast zone and finally to the stations in the region.

Similar to the estimation of peak demand savings from codes and standards, summer and winter peak demand reduction percentages from program savings were developed by sector. The sectoral peak reduction percentages were derived by comparing the forecasted peak demand savings with the corresponding gross forecasts in the Northeast zone. They were then applied to the sectoral gross peak forecast of each station in the region. Summer and winter peak demand savings were analyzed separately.

By 2044, the residential sector in the region is expected to see about 9.2 per cent summer peak demand savings through codes and standards and programs, while commercial sector and industrial sector will see about 22.4 per cent and 1.4 per cent summer peak reduction respectively. Winter peak reductions by 2044 were estimated as 5.7 per cent, 15.1 per cent and 1.4 per cent from residential, commercial and industrial programs respectively.

The analyses were conducted under normal weather conditions. The resulting forecast savings were applied to gross demand to determine net peak demand for further planning analyses.

The eDSM forecast is provided in the ELS IRRP Appendix Data Tables as:

Table 1 | IRRP Summer eDSM (Codes and Standards + Energy Efficiency) Forecast

Table 2 | IRRP Winter eDSM (Codes and Standards + Energy Efficiency) Forecast

B.4 Installed Distributed Generation and Contribution Factor Assumptions

DG assumptions are provided in the ELS IRRP Appendix Data Tables as:

Table 3 | Distributed Generation Contribution Factor Assumptions

Table 4 | Effective Distributed Generation Summer Capacity Assumptions

Table 5 | Effective Distributed Generation Winter Capacity Assumptions

B.5 Final Peak Forecast by Station

The final demand forecast describes how much electricity will be needed for the region over the years highlighting the assumptions made for the peak demand forecasts. These assumptions include the maximum demand in MW to occur per year in the region, as well as the expected contribution of eDSM and DG to reduce the peak demand. Together, these elements form the net peak demand forecasts which is used to evaluate the required electricity needs over the planning horizon. As a result, in obtaining the net extreme weather forecast, the eDSM and DER assumptions, along with the weather correction factors, were applied to the gross median forecast provided by the LDCs. The final winter and summer results under the reference scenario are shown on Table 1 and Table 2 below.

Alternatively, the aforementioned forecast as well as the remaining high and Customer Transformer Stations (CTS) forecasts can be found in the ELS Appendix Data Tables as:

Table 6 | Summer Non-coincident Planning Forecast

Table 7 | Winter Non-coincident Planning Forecast

Table 8 | Summer Non-coincident High Forecast

Table 9 | Winter Non-coincident High Forecast

Table 10 | Summer CTS Forecast

Table 11 | Winter CTS Forecast

Table 1 | Winter Peak Demand Forecast (MW) by Station

Transformer Station	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Batchawana TS	2.08	2.07	2.15	2.14	2.22	2.21	2.29	2.37	2.36	2.45	2.44	2.53	2.63	2.73	2.82	2.92	2.92	3.01	3.11	3.20
DA Watson TS	9.00	8.94	8.98	8.92	8.94	8.97	8.91	8.94	8.89	9.13	9.29	9.56	9.84	10.13	10.51	10.79	11.08	11.45	11.74	12.11
Echo River TS	16.56	16.69	16.82	17.06	17.17	17.28	17.50	17.63	17.76	18.20	18.76	19.23	19.93	20.42	21.02	21.70	22.30	22.88	23.68	24.37
Goulais Bay TS	9.86	9.90	10.02	10.06	10.17	10.18	10.30	10.32	10.45	10.68	11.03	11.29	11.57	11.96	12.34	12.72	13.10	13.47	13.85	14.22
No. 4 Circuit	23.82	23.88	24.97	25.03	24.99	25.04	25.10	25.16	25.12	25.08	25.06	25.10	25.15	25.25	25.30	25.34	25.34	25.33	25.43	25.54
Andrews TS	0.25	0.25	0.25	0.25	0.25	0.25	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.27	0.27	0.27
Mackay TS	0.040	0.039	0.039	0.038	0.038	0.038	0.038	0.037	0.037	0.036	0.037	0.037	0.037	0.037	0.037	0.038	0.038	0.038	0.038	0.038
Northern Av TS	2.92	2.92	2.91	2.91	2.90	2.90	2.89	2.89	2.88	2.98	2.98	2.98	2.98	2.98	3.08	3.08	3.08	3.08	3.08	3.08
Chapleau DS	11.46	11.65	11.82	11.99	12.17	12.35	12.54	12.73	12.91	13.10	13.29	13.47	13.66	13.85	14.03	14.22	14.41	14.60	14.78	14.97
Chapleau MTS	3.76	3.78	3.80	3.82	3.84	3.86	3.88	3.90	3.92	3.95	3.98	4.02	4.06	4.10	4.14	4.18	4.22	4.26	4.30	4.34
St. Mary's MTS	68.23	69.63	69.97	0	0	71.02	71.36	71.73	72.14	72.58	73.15	73.75	74.48	75.22	75.95	76.68	77.42	78.16	78.92	79.68

Transformer Station	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Tarentorus MTS ³	77.08	77.86	78.63	79.44	80.17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tagona West MTS	0	0	142.8	214.4	213.3	372.3	371.5	371.0	370.5	370.1	370.3	370.7	371.6	372.5	373.3	374.0	374.9	375.6	376.4	377.3

Table 2 | Summer Peak Demand Forecast (MW) by Station

Transformer Station	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Batchawana TS	1.74	1.72	1.80	1.78	1.76	1.93	1.90	1.98	1.96	2.04	2.03	2.12	2.21	2.21	2.30	2.39	2.48	2.48	2.57	2.66
DA Watson TS	6.98	7.24	7.49	7.64	7.90	8.04	8.29	8.45	8.72	8.98	9.17	9.45	9.76	10.07	10.38	10.79	11.10	11.40	11.81	12.11
Echo River TS	14.01	14.32	14.52	14.82	14.98	15.26	15.43	15.72	15.92	16.32	16.82	17.26	17.83	18.31	18.88	19.45	20.01	20.58	21.24	21.80
Goulais Bay TS	6.12	6.15	6.17	6.20	6.20	6.22	6.23	6.25	6.28	6.41	6.56	6.72	6.90	7.17	7.35	7.61	7.79	8.05	8.22	8.49
No. 4 Circuit	22.49	22.54	23.52	23.57	23.52	23.56	23.60	23.55	23.61	23.57	23.54	23.62	23.62	23.62	23.72	23.72	23.82	23.91	24.01	24.21
Andrews TS	0.27	0.27	0.28	0.29	0.29	0.30	0.31	0.31	0.32	0.32	0.33	0.34	0.35	0.36	0.37	0.40	0.41	0.42	0.42	0.44
Mackay TS	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02

³ Note that Tarentorus MTS load is being transferred to Tagona West MTS in 2030
East Lake Superior Region Appendices, 10/01/2026 | Public

Transformer Station	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Northern Av TS	2.48	2.57	2.57	2.56	2.56	2.55	2.55	2.54	2.54	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53
Chapleau DS	9.68	9.85	9.98	10.11	10.25	10.40	10.55	10.69	10.84	10.98	11.13	11.27	11.42	11.57	11.71	11.86	12.00	12.15	12.30	12.44
Chapleau MTS	1.97	1.98	1.98	1.98	1.98	1.98	1.98	1.98	1.99	2.00	2.01	2.02	2.04	2.06	2.08	2.09	2.11	2.13	2.15	2.16
St. Mary's MTS	47.48	47.62	47.73	0	0	49.68	49.78	59.09	59.38	59.65	60.08	60.54	61.32	61.92	62.52	63.11	63.71	64.31	64.92	65.54
Tarentorus MTS	57.77	58.23	58.68	59.16	59.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tagona West MTS	0.00	0.00	140.3	197.3	195.9	358.4	357.2	356.4	355.7	355.0	355.1	355.3	356.1	357.0	357.8	358.7	359.4	360.1	360.9	361.7

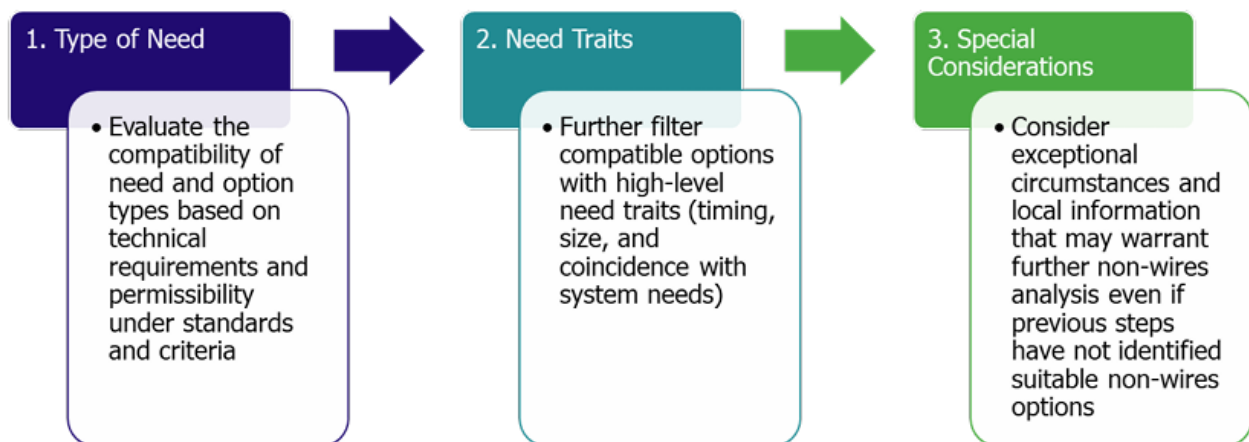
Appendix C. IRRP NWA Screening Mechanism

The IESO developed a [guide](#) to the current general approach for evaluating Non-Wires Alternatives (NWAs) during IRRPs. This guide summarizes various recent improvements made to better consider NWAs when developing an IRRP, including the process flow diagram, screening mechanism, hourly needs characterization, development of options and economic evaluation methodology. Planning participants and stakeholders can refer to this guide to better understand what key activities to expect during the IRRP.

An NWA screening step is carried out early in the IRRP development process after local reliability needs have been quantified but before options analysis begins. The screening mechanism provides a framework to identify suitable option types for the unique needs of each IRRP while improving transparency in the Technical Working Group's decision-making process, driving more consistency between different IRRPs and focusing options analysis efforts on NWAs that are most likely to be feasible and cost-effective. The screening mechanism results in a shortlist of NWAs requiring further investigation. This list informs which local reliability needs require detailed hourly needs characterization and maps candidate options to each need.

The screening mechanism is intended to be a guide rather than a strict set of criteria. It comprises three general steps that are summarized in Figure 3.

Figure 3 | IRRP NWAs Screening Mechanism



The first step in the screening mechanism is a general suitability filter that considers the type of need and the suitability of options according to its technical characteristics and permissibility under applicable planning criteria, such as the [Ontario Resource and Transmission Assessment Criteria](#) (ORTAC), North American Electric Reliability Corporation (NERC) [TPL-001-5.1](#) and Northeast Power Coordinating Council (NPCC) [Directory #1](#).

There are typically five types of needs identified through an IRRP: station capacity needs, supply capacity needs, asset replacement needs, load security needs and load restoration needs. On the other hand, there are four categories of NWAs differentiated by operating characteristics (e.g. dispatchable vs. non-dispatchable), scalability and treatment in current planning criteria. These include: transmission-connected generation or energy storage, eDSM, distributed generation and demand response. Table 3 is the matrix used for the first step in the screening.

Table 3 | Screening Step 1: Suitability by Need and Option Type

Option \ Need	Need				
	Supply Capacity	Station Capacity	Asset Replacement	Load Security	Load Restoration
Transmission-connected Resources	Yes	No	Yes	No	Yes
eDSM	Yes	Yes	Yes	No	No
Distributed generation	Yes	Yes	Yes	No	Yes
Demand response	Yes	Yes	Yes	No	No

After a shortlist of the need/option combinations has been produced, the second step of the screening mechanism further reduces this shortlist by considering the need's high-level characteristics, such as the size of the need and the coincidence with system peak. Table 4 summarizes how this screening is applied to each option.

Table 4 | Screening Step 2: Narrow Down Options Based on High-Level Need Traits

Option	Size of Need	Coincidence of the Need with System Peak
Transmission-connected Resources	Not applicable – always screened in	Always screened in – generation can likely provide system value during provincial peaks even if local need is not coincident
eDSM	Screened in if need is less than 2% of the load forecast in each year	Screened in only if coincident with system peaks
Distributed generation	Screened in if need is less than the available distributed generation connection space	Always screened in – generation can likely provide system value during provincial peaks even if local need is not coincident
Demand response	Screened in if need is proportional to the historically offered amount of demand response in the capacity auction	Screened in only if coincident with system peaks

The third and final step of the screening mechanism does not include a set of criteria – rather, it is to recognize the flexibility in IRRPs for exceptional circumstances and the uniqueness of each region. In some cases, special considerations could warrant further NWA analysis regardless of the screening steps and outcomes described above. To account for the uniqueness of each region, the TWG considers factors such as:

- Government policy or stakeholder support;
- Local preferences around solutions that the community will host;
- Unique load characteristics;
- Opportunities to explore a novel technology or operating model;
- Demand forecast uncertainty;
- Opportunities for integrated solutions; and
- Availability of inexpensive and simple wires options that maximize the use of existing infrastructure.

Appendix D. Hourly Load Forecasting

D.1 General Methodology

Hourly demand profiles or an hourly load forecast is used to better understand the reliability needs in all hours of the year. The forecast consists of a year-long hourly profiles, also known as the “8760 profile”, which is based on the number of hours in a year and scaled to the appropriate annual peak demand. The forecast is also used to help determine potential non-wires solutions to meet the needs and examine their viability.

Hourly demand profiles are first created by training a linear regression model with 5 years of historical hourly data. This data is repeatedly applied under different weather and calendar variable permutations to predict a range of possible future hourly profiles. These future profiles can then be scaled accordingly to match the IRRP’s peak demand forecast.

These models create a relationship between the historical demand data and the selected predictor variables. These variables consist of weather, calendar and non-weather variables and help characterize the load in question over the forecast period.

The weather & calendar variables can include:

- Temperature
- Cloud cover
- Humidity
- Wind chill

The non-weather variables can include:

- Population
- Employment
- Other economic predictors
- COVID impacts
- Global Horizontal Irradiance (to capture embedded solar impacts)
- Calendar (day of week, holidays)

Projection of the non-weather variables can be taken as inputs to the model and do not change during the model run. These projections come from a variety of sources as well including:

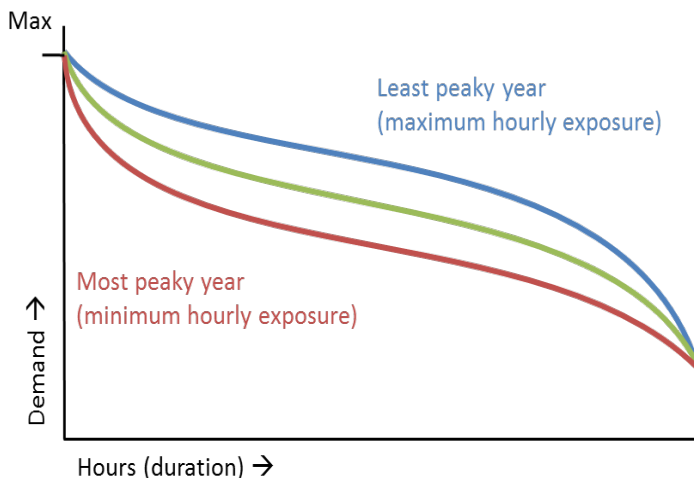
- Forecasts from the Ministry of Finance for the demographic variables

- Forecast providers (such as the Conference Board, Centre for Spatial Economics, etc.) for the economic variables

The model uses 31 years of historical weather data to generate a diverse range of possible demand profiles. They generate 31 annual hourly profiles with each profile consisting of 8760 hours, covering one year. In using many different permutations of weather variables, it helps create many different possible outcomes. The weather profiles are then shifted seven days ahead and seven days behind to capture the impacts of the calendar and weather together on demand. As a result, 465 (15 iterations of the 31 historical years) possible hourly weather forecasts, for each future year, are generated for every station of interest or pocket of stations of interest. For example, the set of possible weather on June 2nd 2023 consists of the historical weather that occurred from every May 26th to June 9th from 1992 to 2022.

The 465 options of future hourly forecasts (together with the forecast of non-weather variables) are then used to produce 465 load forecasts, which are ranked in ascending order based on their total annual energy. Load duration curves illustrating this ranking can be seen in Figure 4.

Figure 4 | Example of Hourly Forecast Scaling



The forecast in the 3rd percentile is the “Extreme Peak” (extreme profile, red curve). The forecast in the 50th percentile is the “Median Peak” (median profile, green curve). The 50th percentile curve was then scaled so that its maximum matched the peak demand forecast.

Hourly forecasts are a direct input for further NWAs assessments when combined with the relevant local transmission limits. The shape of the forecasted load that exceeds transmission limits is referred to as the need profile, or energy-not-served. Need profiles help identify key characteristics – the magnitude, frequency and duration of possible need events and how they could be dispersed over the days, months and years in the 20-year planning horizon.

D.2 Heat Maps

The 8760 profiles are analyzed using heat maps to calculate the proportion of hours exceeding various thresholds and visually represent the data. For this IRRP, need characterization was conducted for the Sault St. Marie (SSM) and the Chapleau DS + DS2 area. These areas are linked to

the needs identified in the study. The Algoma need, however, was not included as performing a Non-Wires Alternative analysis was not necessary. This is due to the nature of the need where a RAS upgrade was identified as the appropriate solution.

D.2.1 Sault St. Marie Supply Capacity Need

The heat map for the monthly SSM supply capacity need in the final year of the forecast, 2044, is depicted on Figure 5. Each cell in the heat map indicates the expected proportion of the magnitude of the need, for each month of the year. The heat map indicates that the need peaks in January and February and the number of days of need is greatest in February. For instance, 1.7% of hours in January are projected to have a supply capacity need greater than 80 MW while in February, it is 3.6% of hours. In essence, the total magnitude of supply capacity need in MW is greater in February in comparison to January.

Figure 5 | Percent of SSM Need by Month for 2044

Size of Need (MW)	January	February	March	April	May	June	July	August	September	October	November	December
80	1.7%	3.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
70	9.1%	7.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
60	8.0%	11.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%
50	13.1%	11.8%	0.0%	0.0%	8.6%	0.0%	0.0%	0.0%	0.0%	1.2%	1.8%	5.4%
40	17.4%	16.6%	19.2%	0.0%	21.9%	0.0%	26.3%	22.3%	0.0%	9.2%	15.3%	19.7%
30	17.1%	19.5%	17.1%	0.0%	5.4%	7.0%	29.2%	9.6%	0.0%	29.9%	21.5%	22.1%
20	16.4%	14.8%	29.4%	0.0%	20.5%	43.6%	23.1%	0.0%	38.4%	27.8%	30.4%	20.1%
10	12.6%	9.7%	26.1%	0.0%	27.3%	35.8%	17.0%	50.8%	21.7%	23.7%	22.5%	22.2%
0	4.5%	4.4%	8.2%	100.0%	16.3%	13.6%	4.4%	17.3%	39.9%	8.1%	8.6%	8.9%
-10	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Figure 6 also shows a visual representation of the hourly SSM supply capacity need during the winter months, such as the month of January in 2044. The winter profile shows that the need is present mainly in the evening and is highest between 17:00 and 18:00. For example, 8.7% of the January days in 2044 are expected to have a supply capacity need greater than 80 MW in the 17th hour of the day.

Figure 6 | Percent of Time of SSM Need by Hour for January, 2044

Size of Need (MW)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
80	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	8.7%	5.7%	0.0%	0.0%	0.0%	0.0%	0.0%
70	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	14.2%	6.9%	20.9%	26.5%	6.0%	0.0%	0.0%	0.0%
60	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	33.9%	32.9%	39.9%	29.1%	0.0%	6.7%	4.2%	0.0%	21.4%	13.1%	0.0%	0.0%
50	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	16.9%	15.4%	19.5%	27.0%	0.0%	0.0%	0.0%	0.0%	18.9%	15.8%	18.3%	15.8%	12.9%	16.7%	0.0%	0.0%
40	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	13.8%	12.4%	13.6%	0.0%	0.0%	0.0%	0.0%	0.0%	8.0%	13.1%	34.4%	35.4%	10.9%	14.1%	23.6%	0.0%
30	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	35.2%	0.0%	0.0%	0.0%	16.6%	16.5%	14.9%	0.0%	0.0%	16.1%	11.9%	34.0%	4.8%	8.4%	35.7%	21.3%	30.1%	35.5%
20	66.1%	35.9%	0.0%	0.0%	0.0%	51.4%	24.9%	15.9%	30.9%	18.8%	11.6%	10.5%	20.9%	31.6%	12.7%	30.4%	4.7%	10.5%	11.1%	10.7%	24.6%	19.9%	26.0%	26.0%
10	24.9%	0.0%	69.6%	100.0%	100.0%	80.2%	25.8%	24.3%	47.0%	32.0%	32.3%	19.2%	29.3%	16.0%	7.9%	27.9%	14.7%	9.2%	1.2%	2.8%	2.5%	8.8%	22.6%	26.0%
0	9.0%	64.1%	30.4%	0.0%	0.0%	19.8%	22.8%	15.6%	6.3%	9.4%	15.9%	25.7%	9.9%	15.3%	20.7%	14.2%	1.7%	0.9%	0.0%	0.0%	0.0%	1.5%	3.7%	12.5%
-10	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

The complete 8760 profile for the final forecast year, 2044, is provided in the ELS IRRP

Appendix Data Tables file along with these heat maps as:

Table 12 | 8760 Profile of Sault St. Marie Supply Capacity Need (2044)

Table 13 | Heat Map of Sault St. Marie Monthly Supply Capacity Need (2044)

Table 14 | Heat Map of Sault St. Marie Hourly Summer Need (2044)

Table 15 | Heat Map of Sault St. Marie Hourly Winter Need (2044)

D.2.2 Chapleau DS + DS2 Supply Capacity Need

Figure 7 portrays the heat map for the monthly Chapleau supply capacity need in the final year of the forecast, 2044. Each cell in the heat map highlights the percentage of hours the load level is over the limit by each month of the year. Based on the findings, the need in the area peaks in February and the number of days of need is greatest is also in February. For instance, 0.9% of hours in February are projected to have a supply capacity need greater than 7 MW.

Figure 7 | Percent of Time Chapleau Need by Month for 2044

Size of Need (M..	January	Februa..	March	April	May	June	July	August	Septe..	October	Novem..	Decem..
7	0.0%	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	2.7%	7.5%	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	14.3%	17.3%	7.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.6%
4	34.6%	25.9%	19.0%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.2%	23.3%
3	22.8%	22.2%	25.9%	15.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	46.3%	28.1%
2	12.7%	17.9%	22.1%	36.5%	0.0%	0.0%	0.0%	0.0%	0.0%	3.9%	31.7%	25.8%
1	10.1%	7.2%	19.1%	36.3%	0.0%	0.0%	0.0%	0.0%	19.5%	59.6%	12.7%	12.9%
0	2.7%	1.0%	4.5%	11.1%	100.0%	0.0%	0.0%	100.0%	80.5%	36.5%	5.1%	3.4%
-1	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Figure 8 also provides the heat map for the hourly Chapleau supply capacity need during the winter months, such as the month of January in 2044. The winter profile shows that the need is present throughout the day and is highest on the 4th hour of the day. For example, 12.4% of the January days in 2044 are expected to have a supply capacity need greater than 6 MW in the 4th hour of the day.

Figure 8 | Percent of Time of Chapleau Need by Hour for January, 2044

Size of Nee...	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
6	0.0%	0.0%	0.0%	0.0%	12.4%	6.1%	0.0%	0.0%	0.0%	6.8%	6.2%	5.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.0%	6.4%	6.4%
5	12.7%	7.3%	7.2%	17.0%	21.4%	22.2%	0.0%	0.0%	20.5%	17.6%	22.0%	26.8%	16.7%	0.0%	6.0%	0.0%	30.9%	15.8%	0.0%	0.0%	12.5%	26.0%	16.5%	11.3%
4	32.1%	30.1%	40.7%	29.2%	32.4%	37.0%	7.8%	0.0%	39.3%	45.4%	37.8%	35.7%	46.6%	37.1%	37.0%	42.9%	34.1%	40.5%	0.0%	0.0%	36.5%	35.7%	47.0%	48.0%
3	30.1%	39.0%	29.1%	37.7%	18.6%	18.9%	25.1%	17.6%	19.1%	14.3%	7.6%	12.8%	10.5%	30.4%	30.3%	29.9%	13.0%	24.0%	48.2%	28.4%	37.5%	15.0%	15.0%	18.9%
2	12.5%	14.2%	14.4%	10.6%	2.7%	6.7%	56.6%	52.6%	16.0%	6.1%	14.3%	4.6%	11.0%	17.3%	9.5%	12.1%	9.1%	10.5%	23.7%	51.5%	0.0%	8.8%	4.4%	2.4%
1	10.6%	3.7%	4.1%	3.9%	10.7%	6.7%	3.4%	26.0%	0.0%	7.6%	9.6%	11.6%	13.1%	13.1%	13.7%	11.7%	8.5%	24.5%	14.3%	12.9%	6.3%	9.7%	11.8%	
0	2.0%	5.7%	4.4%	4.5%	1.9%	2.3%	7.1%	3.8%	5.1%	2.2%	2.4%	2.6%	2.2%	2.1%	3.5%	3.5%	0.6%	0.7%	3.6%	5.7%	0.6%	2.2%	1.1%	1.2%
-1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

The complete 8760 profile for the final forecast year, 2044, is provided in the ELS IRRP

Appendix Data Tables file along with these heat maps as:

Table 16 | 8760 Profile of Chapleau DS + DS2 Supply Capacity Need (2044)

Table 17 | Heat Map of Chapleau DS + DS2 Monthly Supply Capacity Need (2044)

Table 18 | Heat Map of Chapleau DS + DS2 Hourly Summer Need (2044)

Table 19 | Heat Map of Chapleau DS + DS2 Hourly Winter Need (2044)

Appendix E. Electricity Demand Side Management

As a low-cost resource, eDSM offers significant benefits to individuals, businesses and the electricity system as a whole. Targeting eDSM in areas of the province with regional and local needs can help offset investments in new resources or transmission, defer this spending to a later date and/or can complement these investments as part of an integrated solution for the area.

To understand the scale of opportunity and associated costs for targeting eDSM in a local area, data and assumptions can be leveraged from provincial eDSM potential forecasts. In 2019, the IESO and the OEB completed the first integrated electricity and natural gas achievable potential study in Ontario (2019 APS). The main objective of the APS was to identify and quantify energy savings potential (for both electricity and natural gas), greenhouse gas emission reductions and associated costs from demand-side resources for the period from 2019-2038 under different scenarios. This achievable potential modeling is used to inform:

- Future energy efficiency policy and/or frameworks;
- Program design and implementation; and
- Assessments of eDSM non-wires potential in regional planning.

The 2019 APS determined that both electricity and natural gas have significant cost-effective energy efficiency potential in the near and longer terms. In particular, the maximum achievable potential scenario is one scenario in the APS that estimates the available potential from all eDSM measures that are cost effective from the provincial system perspective – i.e., they produce benefits from avoided energy and system capacity costs that are greater than the incremental costs of the measures.

The results of the 2019 APS were updated with the 2022 Achievable Potential Study (2022 APS). The 2022 APS shows that under the maximum achievable potential scenario, eDSM measures have the potential to reduce summer electricity peak demand by up to 3,500 MW in the province over the 20-year forecast period and can produce up to 28 TWh of energy savings over the same period.

After scaling this level of forecasted maximum achievable savings potential to the local area, the forecasted savings that are expected to come from existing provincial and federal eDSM programs, the forecasted savings that are expected to come from future anticipated eDSM programs, as well as savings from codes and standards, were netted out and the remaining achievable savings potential were identified. The remaining potential provides an estimate of the amount of incremental eDSM savings potential that could help address emerging local needs in the East Lake Superior region.

Other province-wide eDSM programs such as the smart thermostat “Peak Perks” program, Retrofit Program, Nome Renovation Savings Program and the Energy Affordability Program are expected to remain in place and contribute to energy savings. Across the ELS region, eDSM measures remain an important tool for supporting both short-term and long-term growth.

E.1 Incremental Energy Savings Forecasts for the ELS Region

It is estimated that eDSM has the potential to reduce demand in the ELS region in the Northeast zone. In the near-term, a portion of these achievable savings opportunities are captured by the [2021-2024 Conservation and Demand Management Framework](#), its evolution under the [2025-2036 Electricity Energy Efficiency Framework](#) and Federal energy efficiency programs. Over time, new opportunities emerge with savings potential available across all sectors in this zone. The 2021-2024 Conservation and Demand Management Framework was based on energy efficiency programs centrally delivered by the IESO under the “Save on Energy” brand to commercial, institutional, industrial, on-reserve First Nations communities and residential customers.

In January 2025, the provincial government announced a new eDSM framework for 2025-2036 with the following priority areas:

1. A more enduring funding framework that potentially looks beyond a four-year timeframe to provide sustained market confidence.
2. Expanded program offerings that reflect consumer and electricity system needs.
3. Objectives and targets for beneficial electrification programs, consumer education and capacity building.
4. Feasibility and design options for demand flexibility (reducing, increasing or time shifting customer load) and distributed energy resource programs.
5. Enhanced involvement of LDCs to help meet customer and electricity grid needs.
6. Continuing programs for income-eligible residential customers and Indigenous communities.
7. Improving the participant experience through enhanced electricity and natural gas energy efficiency program coordination.

The following figures below are obtained by applying the zonal rates of savings potential from the last provincial APS to the demand forecasts to determine the achievable eDSM savings for the stations in the ELS region. Through the screening process (refer to Table 4), only the following areas were applicable for eDSM savings: Chapleau DS, Chapleau DS+MS and the Sault Ste Marie 115 kV interface.

Figure 9 depicts the eDSM potential for Chapleau DS, which is estimated to reach approximately 1.91 MW based on the winter forecast.

Figure 9 | Estimated Incremental eDSM Potential at Chapleau DS

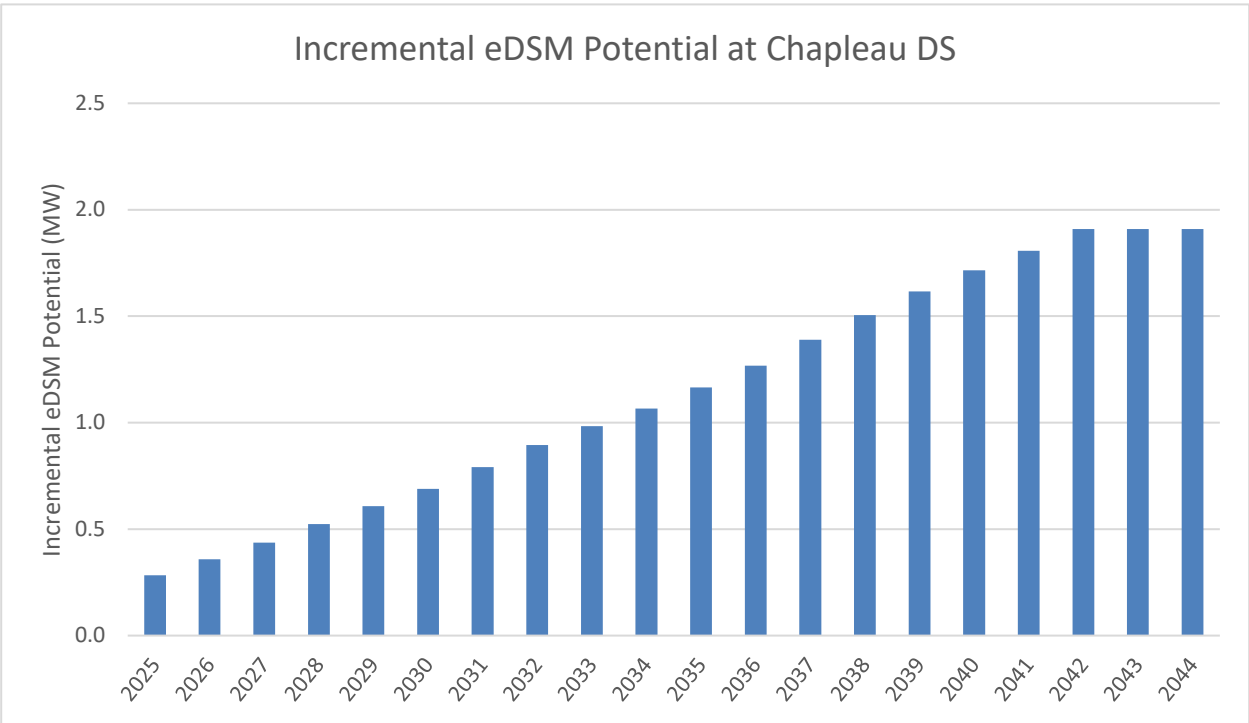


Figure 10 shows the eDSM potential for the Chapleau DS + Chapleau DS2 area, up to 2.33 MW by 2044.

Figure 10 | Estimated Incremental eDSM Potential at Chapleau DS + Chapleau DS2

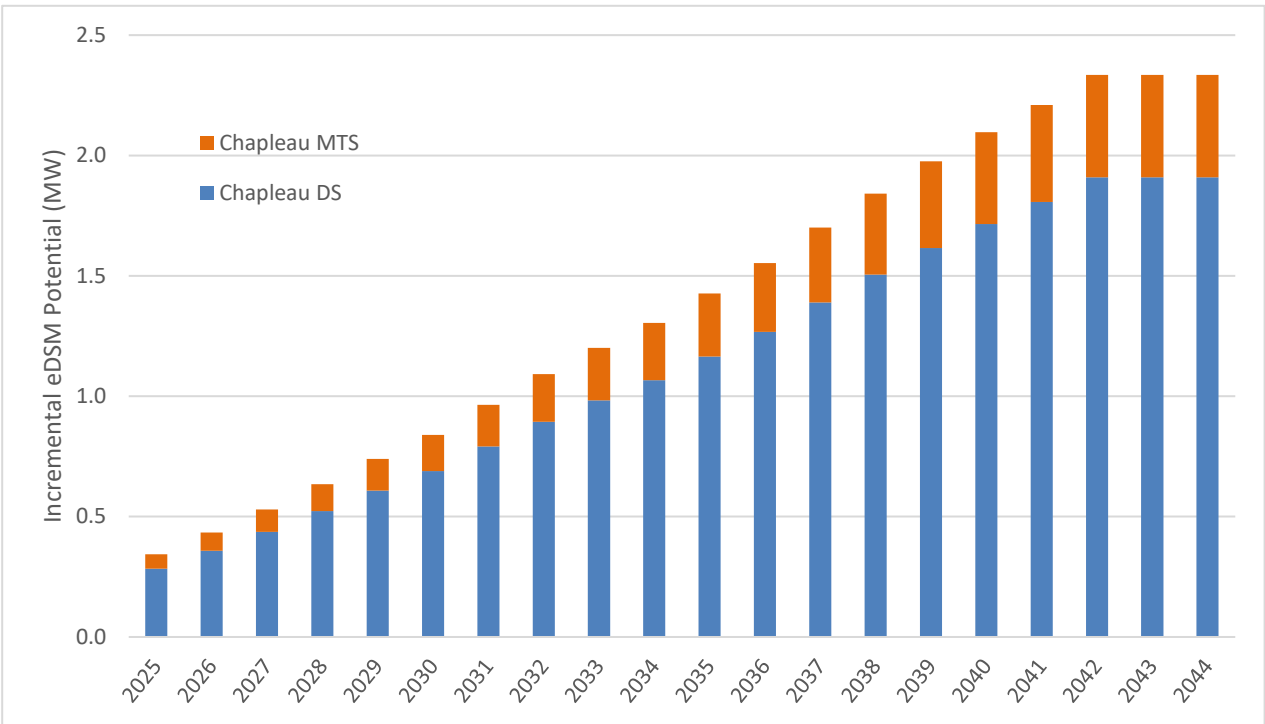
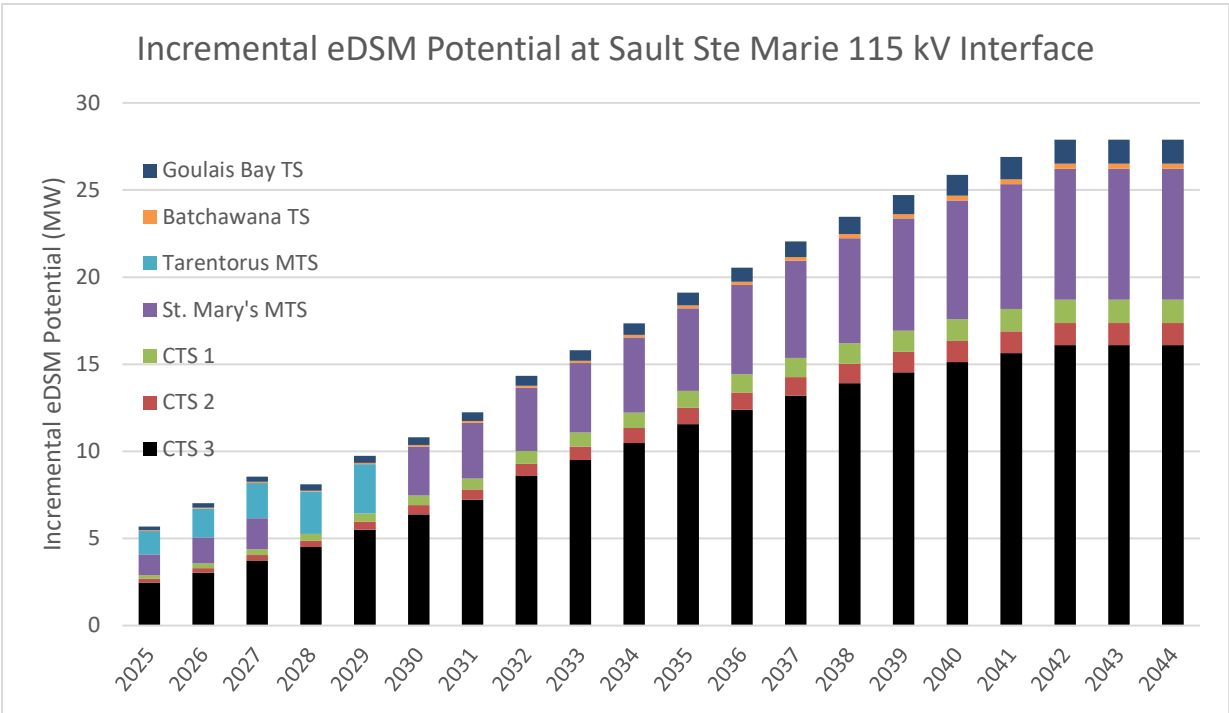


Figure 11 shows the eDSM potential for the Sault Ste Marie 115 kV interface. This interface includes St. Mary's MTS, Tarentorus MTS, Batchawana TS, Goulais Bay TS and three industrial customers in the area. This potential reaches approximately 28 MW by 2044 based on the winter demand forecasts.

Figure 11 | Estimated Incremental eDSM Potential at Sault Ste Marie 115 kV interface



Appendix F. Options and Assumptions

F.1 Economic Assumptions

An economic analysis was conducted to compare the relative net present value (NPV) of the feasible IRRP alternatives. The relative performance of the option or combination of options will inform the most cost-effective option(s) to meet the region's needs.

Various resource options were considered for each need which is further explained in the subsequent subsections. Several assumptions were also made during the economic assessment which can be seen in the following list.

- Various emitting and non-emitting resource options were considered creating a range of costs for Non-Wire Alternatives (NWAs).
- Emitting resources considered included Gas Turbine (SCGT), with overnight capital costs, fixed operating and maintenance (FOM), sourced from 2024 Annual Technology Baseline (ATB) data by The National Renewable Energy Laboratory (NREL).
- Natural gas fuel costs and carbon costs assumptions from 2025 Annual Planning Outlook (APO).
- NWA emitting and non-emitting levelized costs is based on 2024 ATB data from NREL and the 2024 Financial Assumptions; however, the values are converted to Canadian (CAD) 2026\$
- System benefits based on the 2025 APO Capacity Expansion (CapEx) portfolio
- All dollar figures are \$2026 Real, inflation rate is assumed to be 2% per year and social discount rate is 4% Real
- Net present value (NPV) from 2026 to 2070, with the Transmission (Tx) option commencing in 2031 for 40 yrs and the NWA aligning with this Tx timeline
- Land Requirements Supplemental Information:
 - 1 Football Field = 1.32 Acres = 0.53 Hectares (Source: American football field – Wikipedia)
 - Wind Land Requirement = 34 Hectares/MW (Source: Land-Use Requirements of Modern Wind Power Plants in the United States (nrel.gov))
 - Solar Land Requirement = 3.04 Hectares/MW (Source: <https://www.nrel.gov/docs/fy13osti/56290.pdf>)
 - Battery Land Requirements = 0.65 Hectares/200MWh (or 0.003 Hectares/MWh) (Source: Goreway - Battery Energy Storage System - Capital Power)

Note that in the following sections where the Economic Assessment with System Benefit is provided for each need, the "Total Cost (Utility to Commercial Scale for NWA)" is the cost of building the plant for the regional need. Meanwhile, the "System Benefit" is the cost to supply it. When the "Net Benefit/Cost to Ratepayer" is negative, that would indicate a cost to ratepayers, while a positive value would indicate a benefit to ratepayers.

F.1.1 Station Capacity Need at Chapleau DS

Initially, a station capacity need was identified at Chapleau DS. Although updated information throughout the study proved there was no longer an existing or near term station capacity need, a high level consideration of NWAs was undertaken to assess their potential applicability in the event of a future station capacity need. A summary of this NWA feasibility screening can be seen in Table 5 below.

Table 5 | Chapleau DS: NWA Feasibility Screening

Option	Total Installed Capacity by 2043 (MW)	% of Energy Served 2031 to 2043	Land Requirements by 2043 (km ²)	Technical Feasibility	Rationale
Wind, Solar, BESS	10hr BESS = 22 Wind = 18 Solar = 16 Total = 56	99.19% - 99.98%	6.56 km ²	Infeasible	- Exceeds IBR net connection limit of 9.2 MW in first year of NWA installation in 2031 - Unacceptable levels of unserved energy
Solar + BESS	10hr BESS = 71 Solar = 111 Total = 182	98.93% - 99.83%	3.4 km ²	Infeasible	- Unacceptable levels of unserved energy - Exceeds net connection limit of 9.2 MW in first year of NWA installation (2031)
Wind + BESS	10hr BESS = 29 Wind = 19 Total = 48	99.18% - 99.81%	6.0 km ²	Infeasible	- Unacceptable levels of unserved energy - Exceeds net connection limit of 9.2 MW in first year of the need (2031)
Natural Gas	8	100%	N/A	Feasible	Small (<25 MW) SCGT is feasible as energy served and IBR connection are not issues

Note that, consistent with IESO practice, generation facilities with expiring contracts are not included in this study. Based on the screening, none of the non-emitting NWA options are feasible as they all violate the Inverter-Based Resource (IBR) net connection limit and have issues with meeting load served for the entire forecast period. As a result, Economic Assessment (EA) costs are not relevant for a cost comparison. However, the following economic assessment with system benefit measured can be seen in Table 6 below.

Table 6 | Chapleau DS: Economic Assessment with System Benefit

Options NPV for 2026 to 2070 (\$2026 Real)	Total Cost (Utility to Commercial Scale for NWA)	System Benefits (Utility Scale)	Net Cost (Total Cost minus System Benefits)
Wires: Station overnight capital cost of \$13 M	\$12.6 M	\$0 M	\$12.6 M
Natural Gas	\$77 M	\$31 M	\$46 M

Based on the findings, Natural Gas, although feasible, is a more costly alternative compared to the wires option with a net cost of \$46 M to ratepayers versus \$12.6 M for the wires option. The Natural Gas cost is based on a small <25 MW SCGT facility and its system benefit is assumed to be a larger sized gas facility for provincial needs. However, due to the scale, location, timing of the potential capacity exceedance and other factors identified later in the study period, NWAs are not expected to represent a feasible solution for this station capacity need and will not be required to be advanced as part of this IRRP.

F.1.2 Supply Capacity Need at Chapleau Area

Several NWA options were screened in and out for the supply capacity need at the Chapleau area. This area includes Chapleau DS + DS2. Solar and Wind were particularly screened out because the need required all hours in most of the months which does not match resource characteristics. Battery Electric Storage System (BESS) was also screened out as, in 2043, there are 111 contiguous hours in which the BESS alone cannot meet the need. Consequently, four other NWA options were screened in. These include Wind + Solar + BESS, Wind + BESS, Solar + BESS and Natural Gas. The feasibility screening for these options were studied and are summarized in Table 7 below.

Table 7 | Chapleau DS + DS2: NWA Feasibility Screening

Option	Total Installed Capacity by 2043 (MW)	% of Energy Served 2031 to 2043	Land Requirements by 2043 (km ²)	Technical Feasibility	Rationale
Wind, Solar, BESS	10hr BESS = 11 Wind = 4 Solar = 18 Total = 33	99.9% - 100%	1.91 km ²	Infeasible	• Exceeds net connection limit of 11.34 MW in first year of NWA installation (2031)
Wind + BESS	10hr BESS = 20 Wind = 6 Total = 26	99.81% - 100%	1.96 km ²	Partially Feasible	• Feasible as interim solution from 2031 to 2033 • Exceeds interconnection limit of 11.34 MW in 2034 • Unserved energy is unacceptable in some years

Solar + BESS	10hr BESS = 30 Solar = 45 Total = 75	99.72% - 100%	1.38 km ²	Infeasible	- Exceeds net connection limit of 11.34 MW in first year of NWA installation (2031) - Unserved energy is unacceptable in some years
Natural Gas	5	100%	N/A	Feasible	Small (<25 MW) SCGT is feasible as energy served and IBR connection are not issues

As Natural Gas was the only feasible NWA option to address the supply capacity need at the Chapleau area, an economic assessment with system benefit was evaluated to compare its cost to a wires option. The results is described in Table 8 below.

Table 8 | Chapleau DS + DS2: Economic Assessment with System Benefit

Options NPV for 2026 to 2070 (\$2026 Real)	Total Cost (Utility to Commercial Scale for NWA)	System Benefits (Utility Scale)	Net Cost (Total Cost minus System Benefits)
Wires: Station overnight capital cost of \$35 M	\$33.5 M	\$0 M	\$33.5 M
Natural Gas	\$20 M	\$7 M	\$13 M

Based on the findings, none of the non-emitting NWA options are feasible as they all violate the IBR net connection limit and have issues with meeting load served for the entire forecast period. Natural Gas is also a feasible and a least costly alternative compared to the wires option at \$33.5 M versus \$13 M for Natural Gas. Note that the Natural Gas cost is based on a small <25 MW SCGT facility. System benefit for the gas unit is assumed to be a larger sized gas facility for provincial needs.

F.1.3 Supply Capacity Need at Sault Ste Marie Interface

Various NWA options were screened in and out for this need. Solar, Wind and BESS was screened out. Meanwhile Wind + Solar + BESS, Wind + BESS, Solar + BESS, Natural Gas were screened in. Solar and Wind was screened out as the needs are required in all hours and months which do not match resource characteristics. BESS was screened out also as, in 2043, there are 53 contiguous hours that BESS cannot meet alone. The remaining NWA options were screened in and their feasibility was assessed as shown on Table 9 below.

Table 9 | Sault Ste Marie: NWA Feasibility Screening

Option	Total Installed Capacity by 2043 (MW)	% of Energy Served 2031 to 2043	Land Requirements by 2043 (km ²)	Technical Feasibility	Rationale
Wind, Solar, BESS		No Solar selected so this option is equal to Wind + BESS			

Wind + BESS	10hr BESS = 179 Wind = 54 Total = 233	99.9%	18 km ²	Infeasible	No available net IBR connection room available for this option
Solar + BESS	10hr BESS = 437 Solar = 894 Total = 1331	99.73% - 100%	27 km ²	Infeasible	- Above net connection limit in first year of installation - Unserved energy is unacceptable in some years - Solar + BESS is the least efficient system due to diurnal cycle and continuous load
Natural Gas	95	100%	N/A	Feasible	Not subject to IBR limits, meets energy served requirements

As Natural Gas was the only feasible NWA options to address the supply capacity need at the Sault St. Marie area, an economic assessment with system benefit was evaluated to compare its cost to a wires option. The results is summarized in Table 10 below.

Table 10 | Sault Ste Marie: Economic Assessment with System Benefit

Options NPV for 2026 to 2070 (\$2026 Real)	Total Cost (Utility to Commercial Scale for NWA)	System Benefits (Utility Scale)	Net Cost (Total Cost minus System Benefits)
Wires: Station overnight capital cost of \$40 M	\$39 M	\$0 M	\$39 M
NWA: Natural Gas	\$ 276 M	\$276 M	\$0 M

Based on the economic assessment, Natural Gas is the least cost option to ratepayers with a net cost of \$0 M compared to a wires option of \$39 M. Note that the Natural Gas facility for both the regional cost and system benefit is based on the levelized cost of a large scale SCGT gas plant given the need is for 95 MW.

Appendix G. Planning Study Report

G.1 Introduction

This Planning Study Report presents the results of the power system studies undertaken to assess the expected performance of the electricity system in the East Lake Superior (ELS) Region. The findings of these studies informed the development of planning recommendations outlined in the 2026 ELS IRRP.

G.1.1 Description of Study Area

The ELS study region is located in northern Ontario and is bounded by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and the St. Mary's River and St. Joseph Channel to the south.

The study area includes the City of Sault Ste. Marie and surrounding municipalities such as Wawa, Chapleau, Huron Shores and Dubreuilville.

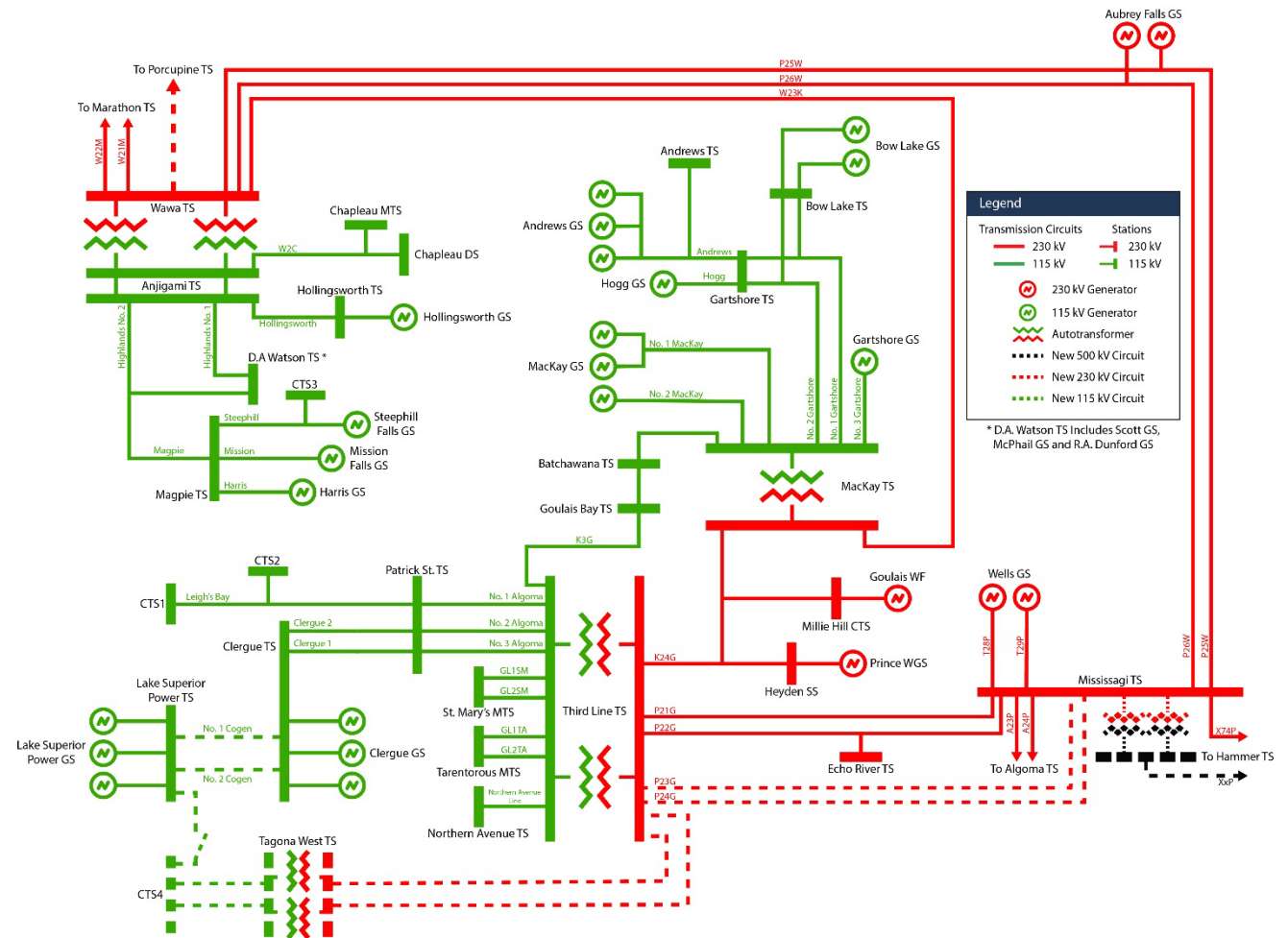
The region is supplied via a 230 kV and 115 kV transmission network with major supply points at Wawa TS, Third Line TS and Mackay TS through autotransformers interconnecting the bulk and sub-transmission systems.

The system includes key 230 kV circuits (e.g., P21G, P22G, P25W, P26W, K24G, W23K) and an extensive 115 kV network supplying local loads.

The region is characterized by:

- A mix of industrial and rural load
- Significant hydroelectric generation resources
- Emerging large-load developments (e.g., Algoma EAF project)
- Dependence on key transmission interfaces for supply reliability

Figure 12 | Single Line Diagram of the ELS Region



G.2 Study Methodology

The planning assessment evaluates system performance over the planning horizon using power system simulation tools under pre- and post-contingency conditions.

The study:

- Applies ORTAC and NERC TPL-001 planning criteria
- Assesses system performance across:
- Thermal loading
- Voltage performance
- Supply capability
- Station capacity
- Incorporates:

- Existing and committed transmission facilities
- Generation resources and contract assumptions
- Forecast demand levels

Analysis is performed under:

- Pre-contingency conditions (all elements in service)
- Post-contingency conditions for credible outages

The methodology also accounts for:

- Operational measures such as RAS and load shedding schemes
- Interface-based assessment of supply capability
- Seasonal (summer and winter) and multi-year (near-, mid-, long-term) conditions

G.3 Study Assumptions

G.3.1 Load Forecast

Load forecasts were developed using inputs from local distribution companies (LDCs) and other planning stakeholders and represent the expected peak demand over the study horizon. Where appropriate, hourly load profiles were developed to support the assessment of non-wires alternatives.

Industrial load forecasts were based on customer-provided information, historical hourly demand data, inputs from LDCs and other available sources. In cases where no information was available, loads were assumed to remain at current output levels.

Finally, unless otherwise specified, all loads were modeled at a power factor of 0.9.

G.3.2 Local Generation Assumptions

The region's generation portfolio consists of hydroelectric, wind and distributed resources.

G.3.2.1 Hydroelectric Generation

The region benefits from numerous hydroelectric facilities, with dependable generation levels summarized in Table 11. The capacity assumptions for hydroelectric generation are based on the overall 98% dependable output of all elements in service and 85% dependable output for outage cases, reflecting the expected availability during peak demand periods. This approach ensures that the analysis accounts for the reliability of hydroelectric resources, which are crucial for meeting the region's energy needs.

Table 11 | East Lake Superior Dependable Hydro Generation

Subsystem	Installed Capacity (MW)	98% Dependable Winter (MW)	85% Dependable Winter (MW)	98% Dependable Summer (MW)	85% Dependable Summer (MW)
ELS	743	173	429	145	159

G.3.2.2 Wind Generation

Wind facilities have been modelled based on summer and winter capacity contribution factors from IESO's Annual Planning Outlook (APO). These factors are multiplied by their peak capacities to determine their expected contributions to the grid for summer and winter. The following is a list of transmitted connected wind resources.

Table 12 | East Lake Superior Wind Resources

Wind Resource	Installed Capacity (MW)	Contribution to Peak Winter (MW)	Contribution to Peak Summer (MW)
1	29.16	7.61	3.36
2	29.16	7.61	3.36
3	25.3	6.60	2.92
4	99	25.84	11.41
5	90	23.49	10.37

G.3.2.3 Gas and Distributed Generation

The generation mix also includes distributed resources such as bioenergy and gas facilities. Notably the Chapleau co generator, with a capacity of 5 MW and the Essar gas generator rated at 63 MW are integrated into the analysis until the expiry of their respective contracts. The output from these distributed generation facilities is accounted for as a net reduction in load, emphasizing their role in offsetting demand rather than contributing additional generation to the overall supply.

In addition to the above, the Lake Superior Power (LSP) generators have been recently brought online to support the region during the Electric Arc Furnace (EAF) project ramp up. The total generation from these units includes 50 MW from GTG1, 50 MW from GTG2 and 28 MW from STG1. Their contribution further enhances the reliability of the generation mix.

G.3.3 Major Interface Flows

Table 13 shows the major interfaces that impact this region. The interface flow assumptions are based on the maximum transfer capability of each interface. The baseline assumption will be to assume interface flows at ~95% of their transfer capability to ensure that load growth in the area does not penalize transfer capability in this region.

Table 13 | Interfaces to Monitor

Interface	Description	Transfer Capability (MW)	Assumption (MW)
GLP Inflow	MW Flow west at Mississagi TS on P21G+P22G plus MW flow into Third Line TS on K24G	295	280
East West Tie (EWTW)	MW flow west at Wawa TS on W21M, W22M, W35M and W36M	600	570
East West Tie East (EWTE)	MW Flow east at Wawa TS on W21M W22M, W35M and W36M	600	570

System performance is evaluated under key interface flow conditions, including:

- East-West Transfer East (EWTE)
- East-West Transfer West (EWTW)
- Internal interfaces (e.g., Algoma, Sault Ste Marie 115 kV)

Interface assessments consider:

- Maximum transfer capability under contingency conditions
- Impact of interface limitations on load supply capability

G.4 System Topology

The study models:

- Existing transmission network (230 kV and 115 kV)
- Autotransformers at major stations
- Reactive resources (capacitors, reactors, STATCOMs)
- Committed system reinforcements

Key committed projects include:

- Third Line TS transformer replacement (2027)
- K3G line refurbishment (2026)
- Northeast Bulk transmission reinforcements (2029–2030)

These reinforcements improve system capability but do not fully eliminate all identified limitations.

G.4.1 Remedial Action Schemes and Under Voltage Load Shedding Schemes

This section summarizes all automated protection and control schemes in the study area that are designed to maintain system reliability under contingency conditions. These schemes include:

1. Remedial Action Schemes (RAS): Automated schemes that trip generation, shed load, or reconfigure the network to prevent equipment overloads or voltage collapse following specific contingencies.
 - Third Line Remedial Action Scheme - being upgraded to facilitate Algoma Steel Inc. EAF CTS Connection project. To include the new contingencies and responses arising from the system change, this new Third Line RAS is being formulated to include the current contingencies/control actions and new contingencies/control actions arising out of Algoma Steel Inc. EAF CTS Connection project. The updated Third Line RAS for Load Rejection addresses any post-contingency thermal and voltages issues. The updated scheme provides load rejection capability to mitigate post contingency thermal and voltage criteria violations on the area. It facilitates load and new load West of Mississagi until the North Shore Link and North East Power line are installed as per the North East Bulk Plan. It is required to meet planning requirements under low hydro electric scenarios west of Mississagi. This RAS is replacing the Northwestern System Load Rejection Scheme and the GLP Instantaneous Load Rejection Scheme.
 - Northwest Remedial Action Scheme - This scheme can be armed for the loss of P25W, P26W, W23K and K24G. The selection can include rejection of load in the Sault Ste. Marie area and tripping the shunt devices at Wawa TS.
2. MacKay TS – K3G 115 kV Line – Generation Rejection (G/R) Scheme -The primary purpose of the MacKay TS – K3G 115 kV circuit – Generation Rejection (G/R) Scheme is to ensure the post-contingency loading on K3G 115 kV circuit is within its post-contingency rating for loss of T2 230/115 kV autotransformer at MacKay TS or for the loss of K24G 230 kV line between MacKay TS and Third Line TS under specific transmission system conditions. This scheme is needed for scenarios where the flow on the EWTE interface is high combined with combinations of high generation in the Wawa 115 kV pocket and/or high generation in the Mackay 115 kV pocket. The recent refurbishment of K3G will include a Mackay RAS modification to cross-trip K3G for the contingency on the K24G circuit.

3. Under-Voltage Load Shedding (UVLS): Schemes that automatically disconnect load when system voltages fall below predefined thresholds, helping to maintain voltage stability and prevent cascading outages.
 - Under Voltage Sault Local Load Rejection Scheme - The Under Voltage Sault Local Load Rejection (L/R) Scheme is designed to shed loads connected to the 115kV side of Third Line TS in the event of the voltage dropping below a setpoint. This setpoint is currently set at 108kV. This scheme uses the same six load blocks in GLP Instantaneous Load Rejection Scheme. This load rejection scheme is initiated following the detection of an under-voltage condition at either of the two 115 kV buses at the Third Line TS. None of the contingencies studies utilized this scheme.
4. Under-Frequency Load Shedding (UFLS): Schemes that shed load in response to frequency decline, typically as part of system-wide protection.
 - Third Line TS Under-Frequency Load Shedding (UFLS) Scheme - The Under-Frequency Load Shedding scheme can prevent excessive load shedding during post-contingency situations thereby maximizing system reliability and preventing the Hydro One SSM system from total collapse.

Application in this study:

- All existing schemes are assumed to remain in service and operate as designed.
- Where the operation of these schemes is required to meet ORTAC or NERC TPL-001 performance criteria, this is explicitly noted in the results section.
- Any limitations or gaps in existing schemes should be highlighted, particularly if additional measures are needed to address forecasted needs.

However:

- Some RAS actions result in load rejection exceeding ORTAC limits (150 MW), indicating a reliability concern.

G.5 Criteria and Standards

G.5.1 Planning Performance Criteria

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

- North American Electric Reliability Corporation (NERC) TPL-001 "Transmission System Planning Performance Requirements";
- Northeast Power Coordinating Council (NPCC) Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System"; and

- IESO ORTAC.

Table 14 below shows the types of contingencies assessed and how they map to applicable standards. The table also specifies the thermal loading criteria and amount of load rejection/curtailment permitted by ORTAC.

Table 14 | Mapping of Planning Scenarios to NERC/NPCC Standards and ORTAC Criteria

Pre-contingency	Contingency ⁴	Type	Mapping to TPL/Directory 1 Event	Rating ⁵	Maximum Allowable Load Loss
All elements in-service	None	N-0	P0	Continuous	None
	Single	N-1	P1, P2	LTE	150 MW by-configuration
	Double	N-2	P7, P4, P5	STE, reduced to LTE	150 MW lost by curtailment; 600 MW Total ⁶
Transmission element out-of-service, followed by system adjustments	Single	N-1-1	P6	STE, reduced to LTE	150 MW lost by curtailment; Total 600 MW ⁵
	Double	N-1-2	Cat II	STE, reduced to LTE	N/A

In addition to thermal criteria pre- and post-contingency minimum and maximum voltages and voltage change criteria must be adhered to for all scenarios as per Table 15.

⁴ Single contingency refers to a single zone of protection: a circuit, transformer, or generator. Double contingency refers to two zones of protection; the simultaneous outage of two adjacent circuits on a multi-circuit line, or breaker failure.

⁵ LTE: Long-term emergency rating. 50-hr rating for circuits, 10-day rating for transformers.

STE: Short-term emergency rating. 15-min rating for circuits and transformers.

⁶ The long-term transmission system planning criteria establish the Load Security Criteria which stand Not more than 600MW of load may be interrupted by configuration and by planned load curtailment or load rejection

Table 15 | Maximum and Minimum Allowable Voltages

Applicable Limit	Nominal Bus Voltage (kV)		
	500	230	115
Post-contingency Maximum Voltage	550	250	127
Post-contingency Minimum Voltage	470	207	108
Post-contingency Maximum deviation	10%	10%	10%

The system must be shown to be stable if the most critical parameter is increased by 10%, for the following conditions:

- A pre-contingency power transfer (point a) that is 10% lower than the voltage instability point of the pre-contingency P-V curve and
- A pre-contingency transfer that results in a post-contingency power flow (point b) that is 5% lower than the voltage instability point of the post-contingency curve
- 10% margin on transient instability

Once load is lost either by configuration or by actions such as planned load rejection via a RAS or manual load rejection following a contingency to reduce loading to the LTE ratings, load must be restored in accordance with the following:

- Any load lost must be restored in under 8 hours.
- Any amount of load lost in excess of 150 MW must be restored in 4 hours.
- Any amount of load lost in excess of 250 MW must be restored in 30 minutes.

G.5.2 Studied Contingencies

The following contingencies are assessed:

- N-1: Single element outages
- N-2: Breaker failure and common tower events
- N-1-1: Sequential outages
- Generation outages (N-G-1)

Contingencies include:

- Transmission circuits

- Transformers
- Breaker failure scenarios
- Major interface failures

G.6. Study Results

G.6.1 Existing System Performance

Thermal Performance

- No violations under normal (N-0) conditions
- Post-contingency:
 - Algoma #1 circuit exceeds STE ratings following loss of Algoma #2 and #3 circuits
 - Key circuits (P21G, P23G, P24G) approach limits under contingencies

Voltage Performance

- No widespread steady-state violations
- Voltage collapse risk identified at Third Line TS under autotransformer outage scenarios

G.6.2 Identified Needs

1. Supply Capacity Needs

- Algoma interface constrained by thermal limits under breaker failure to Patrick St 214
- RAS required but exceeds allowable load rejection limits

2. Voltage Stability Needs

- Third Line Auto interface experiences voltage collapse under N-1-1 conditions

3. Thermal Constraints

Overloads on Algoma #1 and selected transmission elements under contingencies

4. Station Capacity Needs

- None

5. Equipment End-of-Life

- Key assets (e.g., K3G line, Third Line T2 transformer) require replacement and being replaced.

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