Integrated Regional Resource Plan

East Lake Superior Region
April 2021

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Powering Tomorrow.

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List of Acronyms

BKF	Breaker Failure
CDM	Conservation and Demand Management
DG	Distributed Generation
ELS	East Lake Superior
EWT	East West Transfer
EWTE	East West Transfer East
EWTW	East West Transfer West
GLPT	Great Lakes Power Transmission
HONI	Hydro One Networks Inc.
HOSSM	Hydro One Sault Ste. Marie LP
IESO	Independent Electricity System Operator
IRRP	Independent Electricity Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
MW	Megawatt
NERC	North American Electric Reliability Corporation
NUG	Non-Utility Generator
NA	Needs Assessment
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board

ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
STE	Short Term Emergency
TS	Transformer Station
TTC	Total Transfer Capability

Integrated Regional Resource Plan
ELS

This Integrated Regional Resource Plan (IRRP) was prepared by the Independent Electricity System Operator (IESO) pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the East Lake Superior (ELS) Region Technical Working Group which included the following members:

- Independent Electricity System Operator
- PUC Distribution Inc.
- Algoma Power Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Hydro One Sault Ste. Marie LP

The Technical Working Group assessed the reliability of electricity supply to customers in the ELS region over a 20-year period beginning in 2020 and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time and align with IESO's bulk planning study for the broader region commencing in 2021.

The ELS Technical Working Group members agree with the IRRP's recommendations and support implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community consultations as required.

The ELS region Technical Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

This report is organized as follows:

- The plan is introduced in Section 1;
- A summary of the recommended plan for the ELS Region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the ELS Region and the study scope are discussed in Section 4;
- Demand forecast, conservation and distributed generation assumptions are described in Section 5;
- Electricity needs in the ELS Region are presented in Section 6;
- Options and recommendations for meeting needs are addressed in Section 7;
- A summary of engagement to date and moving forward is provided in Section 8;
- A conclusion is provided in Section 9.

1. Introduction

This IRRP for the ELS region addresses the regional electricity needs over the study period, i.e., from 2020 to 2040. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of the Technical Working Group composed of IESO, PUC Distribution Inc., Algoma Power Inc., Hydro One Networks Inc. (Distribution), Hydro One Networks Inc. (Transmission) and Hydro One Sault Ste. Marie LP.[1]

In Ontario, planning to meet the electrical reliability needs of a large area or region is carried out through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for the 21 electricity planning regions across Ontario, including the ELS region, at least once every five years.

In this region, the electrical load is comprised of industrial, commercial and residential users and is winter peaking. The ELS region is supplied through 230/115 kV autotransformers at Third Line Transformer Station (TS), Wawa TS and MacKay TS, as well as the 230 kV and 115 kV transmission lines and step-down transformation facilities shown in Figure 1. The region is defined electrically by the 230 kV transmission circuits bounded by Wawa TS to the northwest and Mississagi TS to the southeast.

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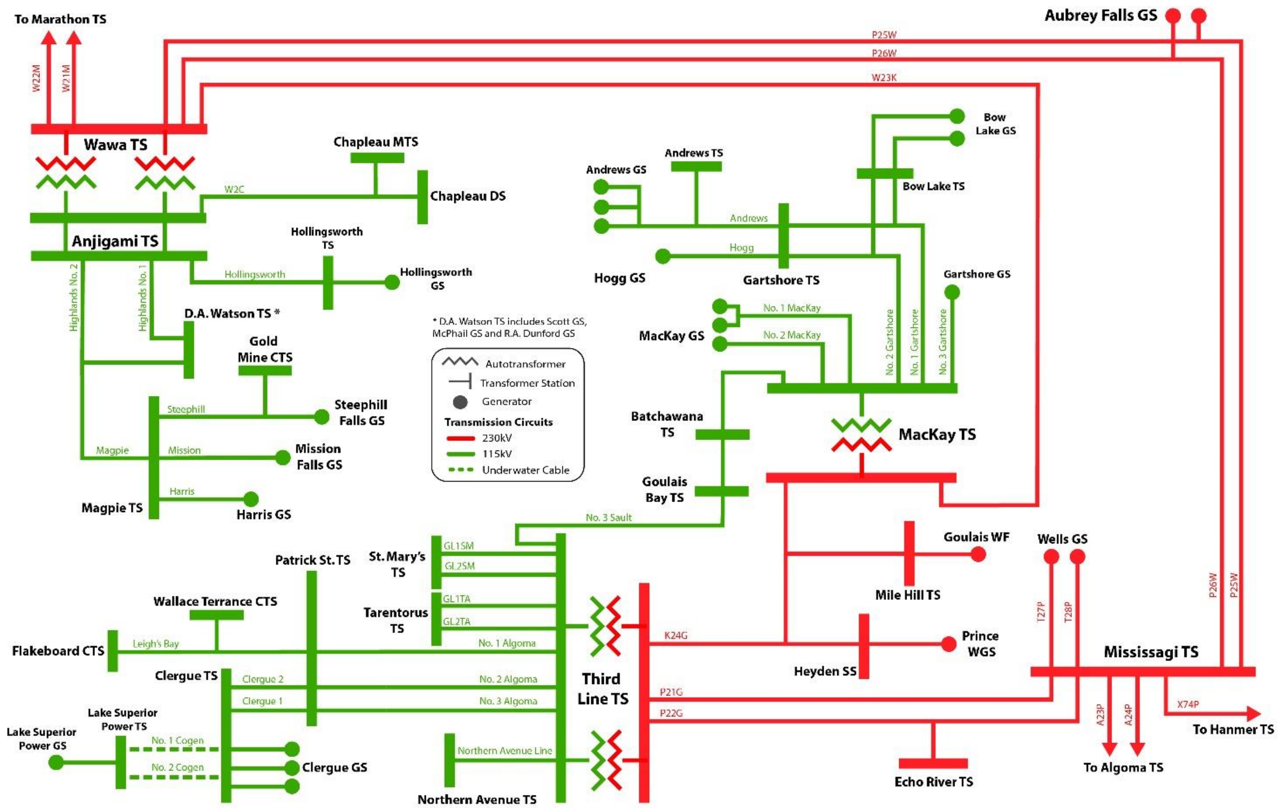
[1] Hydro One Distribution participated on behalf of Chapleau PUC

Figure 1 | ELS Single Line Diagram



2. The Integrated Regional Resource Plan

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

While the demand forecast underpinning this plan is relatively flat over the 20-year planning horizon, there is potential for significant growth in industrial loads directly connected to the high voltage transmission system which can impact the bulk transmission system in the broader region. Accordingly, this high industrial growth is not included in this plan and will be studied as part of the IESO's bulk planning study, starting in 2021.

While the bulk planning study will consider high industrial growth, some of the needs identified as part of this IRRP are linked to the bulk transmission system in the broader region and should thus be considered as part of this study to ensure a coordinated approach. As such, this IRRP has identified the needs for which this coordination is required and has recommended that they be carried forward into the IESO's bulk planning study. For those needs that are not directly linked to the bulk transmission system in the broader region, this IRRP has identified specific recommendations to address them.

2.1 Recommendations of the Plan

The recommended actions to address the region's needs are summarized in Table 2.1 below, together with the details of their implementation.

Table 2.1 | Implementation of Recommended Plan for ELS Region

Need	Recommendation	Lead Responsibility	Required By
Loss of one Third Line TS autotransformer causes the companion autotransformer to be loaded close to its capacity	Monitor load and supply in the ELS region	IESO/HOSSM	Immediately and Ongoing

Need	Recommendation	Lead Responsibility	Required By
Loss of P21G and P22G circuits causes voltage collapse at Third Line TS and other ELS stations	Enable remote arming of GLP Instantaneous Load Rejection Scheme for P21G and P22G double contingency for operational efficiency over manual arming	Hydro One	Immediately
Loss of two Algoma circuits or a Patrick St TS 214 BKF results in thermal overload of the remaining Algoma circuit	Implement automatic load rejection scheme at Patrick St TS	HOSSM	Immediately
During an outage of P25W or P26W circuits, a loss of the K24G circuit results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	Consider as part of the IESO's Bulk Planning Study for the broader region commencing in 2021	IESO/HOSSM	2023
During an outage of one of the Third Line TS autotransformers, a loss of the companion autotransformer results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	Consider as part of the IESO's Bulk Planning Study for the broader region commencing in 2021	IESO/HOSSM	2023
For loss of Anjigami TS, there is an overload on Hollingsworth T1 and T2, and vice versa	Hydro One to work with the LDC to build a new 115/44 kV station that will tap off Hollingsworth 115 kV circuit to accommodate the load increase	HOSSM	2024

3. Development of the Plan

3.1 The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region defined by common electricity supply infrastructure over the near, medium, and long term and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecast growth and customer reliability, develops and evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the OEB in 2013 and is performed on a five-year planning cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitter(s) and LDC(s) in each planning region.

The process consists of four main components:

- A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
- A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
- An IRRP, led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
- A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Regional Planning is one type of electricity planning in Ontario; other types include Bulk System Planning and Distribution System Planning (local planning). A key benefit of the regional planning process is that it provides an opportunity for the entities leading these various planning activities to develop efficient planning outcomes when considering the needs and alternatives as a whole.

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

The IESO has also finalized a review of the Regional Planning Process to consider lessons learned and findings from the previous cycle of regional planning and other regional planning development initiatives, such as pilots and studies. The recommendations and next steps from this review are available in the Regional Planning Process Review Final Report which is published on the IESO's website.

3.2 IESO's approach to Regional Planning

In assessing electricity system needs for a region over a 20-year period, IRRPs enable near-term actions to be developed in the context of a longer-term view of trends. This enables coordination and consistency with the long-term plan.

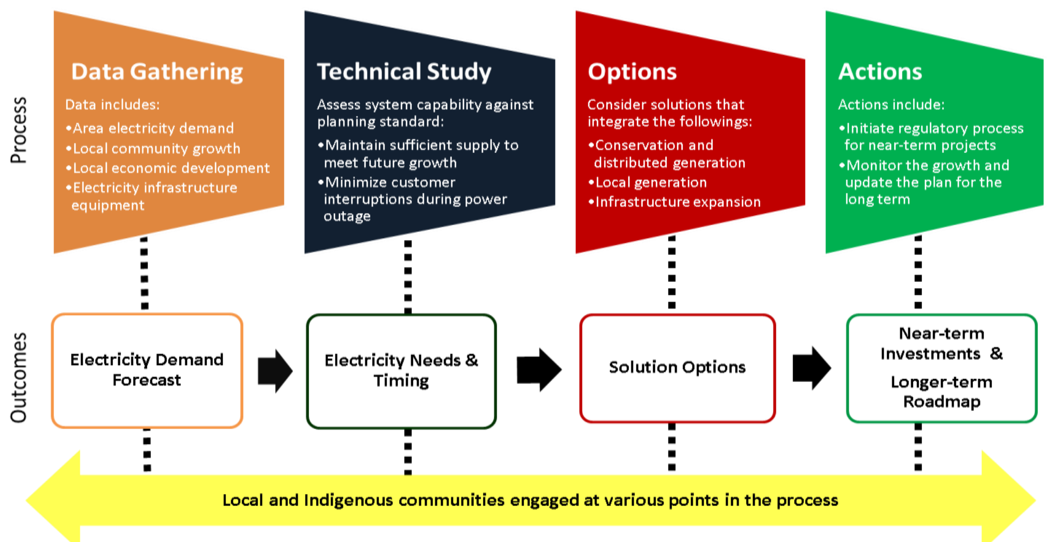
In developing this IRRP, the Technical Working Group followed a number of steps (See Figure 3.2) including:

- Data gathering, including development of electricity demand forecasts;
- Conducting technical studies to determine electricity needs and the timing of these needs;
- Developing and evaluating potential options; and
- Preparing a recommended plan including actions for the near and longer term.

Throughout this process, engagement was carried out with stakeholders with an interest in the area.

The IRRP documents the inputs, findings and recommendations developed through the process described above and provides recommended actions for the various entities responsible for plan implementation. The IRRP helps ensure that recommendations to address near-term needs are implemented, while maintaining the flexibility to accommodate changing long-term conditions.

Figure 3.2 | Steps in the IRRP Process



3.3 ELS Technical Working Group and IRRP Development

The second cycle of regional planning in ELS was initiated in April 2019. In June 2019, Hydro One published the Needs Assessment report for the region which included input from the IESO, Algoma Power, Chapleau PUC, Hydro One Distribution, Hydro One Sault Ste. Marie and PUC Distribution Inc. The Needs Assessment report identified needs which required coordinated regional planning and, therefore, the IESO conducted a Scoping Assessment process and issued the Scoping Assessment Outcome Report in October 2019. This report ultimately recommended that an IRRP be conducted for the region to assess the needs requiring a coordinated regional approach.

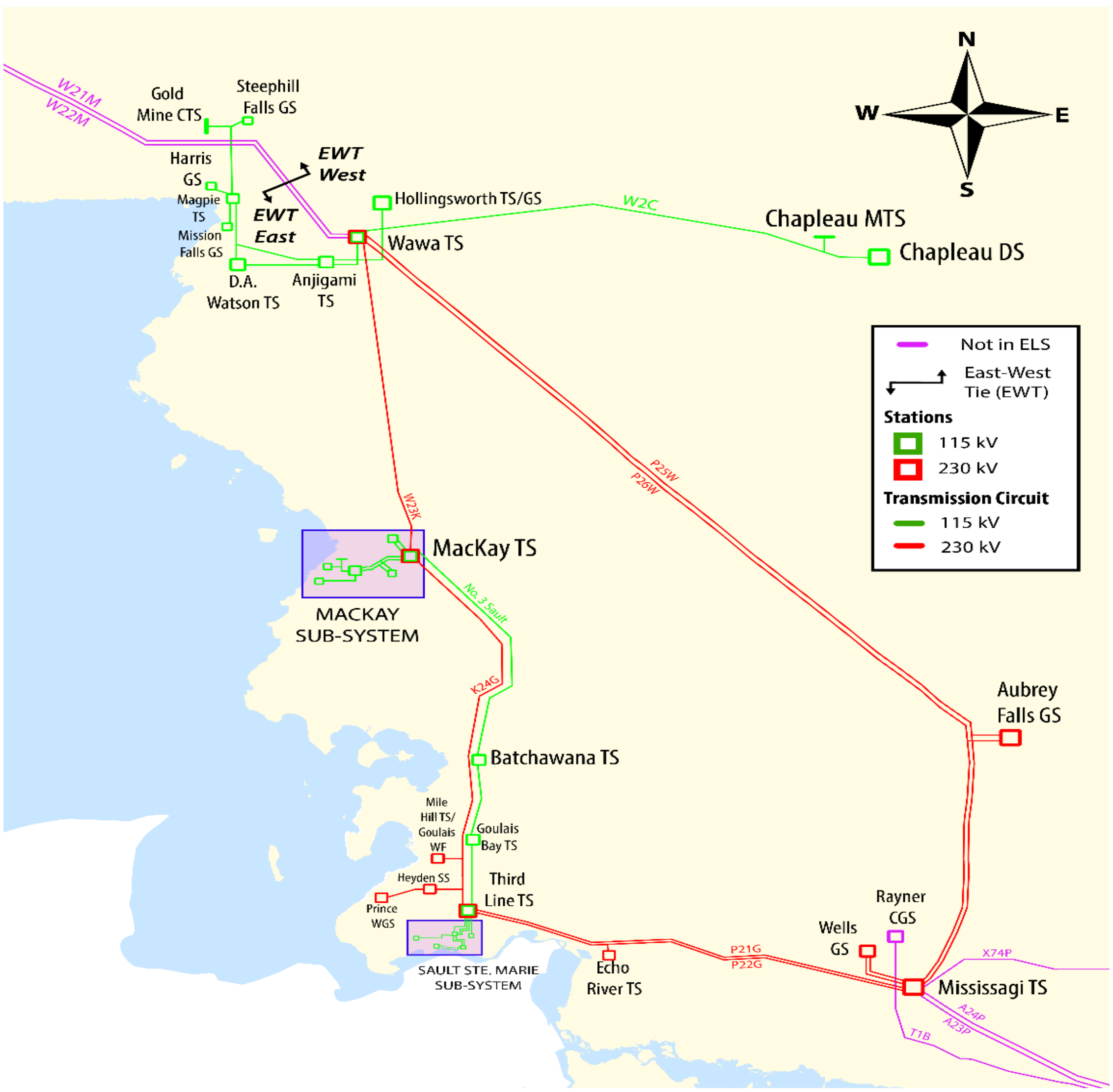
The Technical Working Group then gathered data, performed technical studies to identify the region's reliability needs, evaluated options to address the needs and developed the recommended actions included in this IRRP.

4. Background and Study Scope

In geographical terms, the region extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and St. Mary's River and St. Joseph Channel to the south as shown in Figure 4.1 below.

The region is supplied from a combination of local generation and connection to the Ontario electricity grid via a network of 230 kV and 115 kV transmission lines and stations. The transmitters in the region are Hydro One Sault Ste. Marie LP (HOSSM) and Hydro One Networks Inc. (Hydro One); the local distribution companies (LDCs) are Algoma Power Inc., Chapleau PUC, Hydro One Distribution and PUC Distribution Inc.

Figure 4.1 | ELS Transmission System



4.1 History of Electricity Planning in the ELS Region

This is the second cycle of regional planning for the ELS region. In the first cycle, a Needs Assessment was completed by Hydro One in late 2014 which did not identify electricity needs in the next 10 years requiring regional coordination. The Needs Assessment report identified issues for which local wires only solutions were to be developed.

4.2 Study Scope

This IRRP was prepared by the IESO on behalf of the Technical Working Group and recommends options to meet the electricity needs of the ELS region of the study period with a focus on providing an adequate, reliable supply to support community growth. The objectives and scope of this IRRP are set out in the Scoping Assessment, together with the roles and responsibilities of the Technical Working Group members.

The transmission facilities in-scope of the ELS IRRP are described below:

- 230/115 kV autotransformers- Third Line TS, Wawa TS, Mackay TS;
- 230 kV connected stations- Mississagi TS, Echo River TS, Heyden CSS, Mile Hill CTS;
- 115 kV connected stations- Anjigami TS, Chapleau MTS, Chapleau DS, Hollingsworth TS, DA Watson TS, Magpie TS, Gold Mine CTS, Flakeboard CTS, Wallace Terrance CTS, Patrick St TS, Lake Superior Power TS, Clergue TS, Northern Avenue TS, Goulais Bay TS, Batchawana TS, Gartshore TS, Andrews TS and Bow Lake TS, St. Mary's MTS, Tarentorus MTS;
- 230 kV transmission lines – P25W, P26W, W23K, K24G, P21G, P22G, T28P, T27P;
- 115 kV transmission lines – W2C, High Falls No. 1. High Falls No. 2, Magpie, Harris, Mission, Steephill, Andrews, Hogg, No. 1 Mackay, No. 2 Mackay, No. 1 Gartshore, No. 2 Gartshore, No. 3 Gartshore, Sault No.3, No. 1 Algoma, No. 2 Algoma, No. 3 Algoma, Clergue 1, Clergue 2, Leigh's Bay, No. 1 Cogen, No. 2 Cogen, GL1SM, GL2SM, GL1TA, GL2TA;
- 115 kV generation assets – Hollingsworth GS, Harris GS, Mission Falls GS, Steephill Falls GS, Andrews GS, Bow Lake GS, Hogg GS, Gartshore GS, Mackay GS, Clergue GS, Lake Superior CGS;
- 230 kV generation assets – Aubrey Falls GS, Wells GS; and
- Storage – Sault Ste. Marie Energy Storage at St. Mary's MTS.

The ELS IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe;
- Examining the Load Meeting Capability ("LMC") and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying NERC standards and ORTAC;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid as described in Section 7 of ORTAC;

- Confirming identified end-of-life asset replacement needs and timing with HOSSM and Hydro One;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible energy efficiency, generation, transmission and/or distribution, and other approaches such as Non-Wires Alternatives;
- Engaging with the community on needs, findings, and possible alternatives;
- Evaluating alternatives to address near and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

4.2 IESO’s Bulk Planning Study

While the demand forecast underpinning this plan is relatively flat over the 20-year planning horizon, there is potential for significant growth in industrial loads directly connected to the high voltage transmission system which can impact the bulk transmission system in the broader region. Accordingly, this high industrial growth is not included in this plan and will be studied as part of the IESO’s bulk planning study, starting in 2021.

While the bulk planning study will consider high industrial growth, some of the needs identified as part of this IRRP are linked to the bulk transmission system in the broader region and should thus be considered as part of this study to ensure a coordinated approach. As such, this IRRP has identified the needs for which this coordination is required and has recommended that they be carried forward into the IESO’s bulk planning study. For those needs that are not directly linked to the bulk transmission system in the broader region, this IRRP has identified specific recommendations to address them.

5. Electricity Demand Forecast

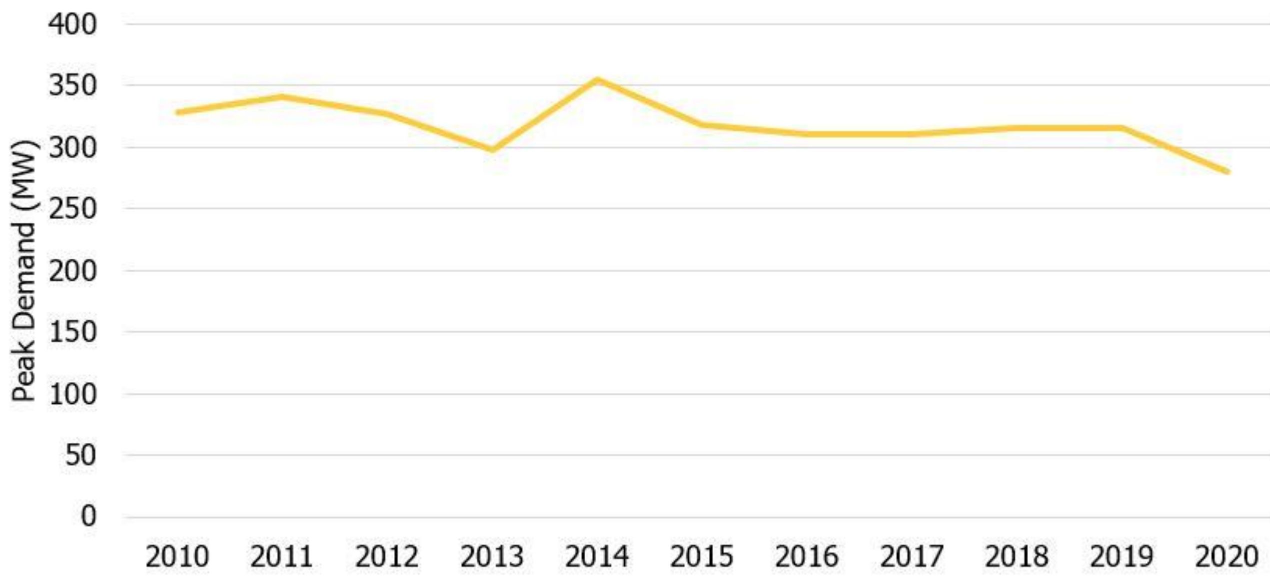
A fundamental consideration in any electricity supply study is how much electricity will be required in the region over the study period. This section describes the development of the demand forecast within the ELS Region over the 20-year study period, highlighting the assumptions made for peak demand load forecasts (i.e., the maximum demand in MW forecasted to occur in each year), including the expected contribution of conservation and demand management, and Distributed Generation (DG) to reducing peak demand. When combined, these factors produce the net peak demand forecast used to assess the electricity needs of the area over the planning horizon.

To evaluate the reliability of the electricity system, regional planning is concerned with the coincident peak demand for a given area, or the demand observed at each station for the hour of the year in which overall demand in the study area is at a maximum. This represents the moment when assets are at their most stressed, and resources generally the most constrained. This differs from a non-coincident peak, which is the sum of individual peaks at each station, regardless of whether these peaks occur at different times.

Within the ELS region, the peak loading hour for each year typically occurs in the evening in the winter season and is driven by electrical heating demand in the residential sector as access to natural gas is limited in the area. In addition, the region is home to a number of large industrial customers, in the manufacturing and mining sectors, that consume large amounts of energy (i.e., the total amount of electricity flowing through the system over time and typically measured in MWh) over the course of a year. Energy consumption by these customers can be impacted by economic conditions, such as commodity prices.

Historical winter peak demand in the region has decreased from 355 MW in 2014 to 280 MW in 2020. This decline is primarily due to the closure of large industrial customers in the pulp and paper sector. COVID-19 is also expected to have contributed to the decline observed in 2020. Figure 5.0 shows the historical winter peak demand in the ELS region.

Figure 5.0 | Historical Peak Demand in the ELS Region (2010-2020)



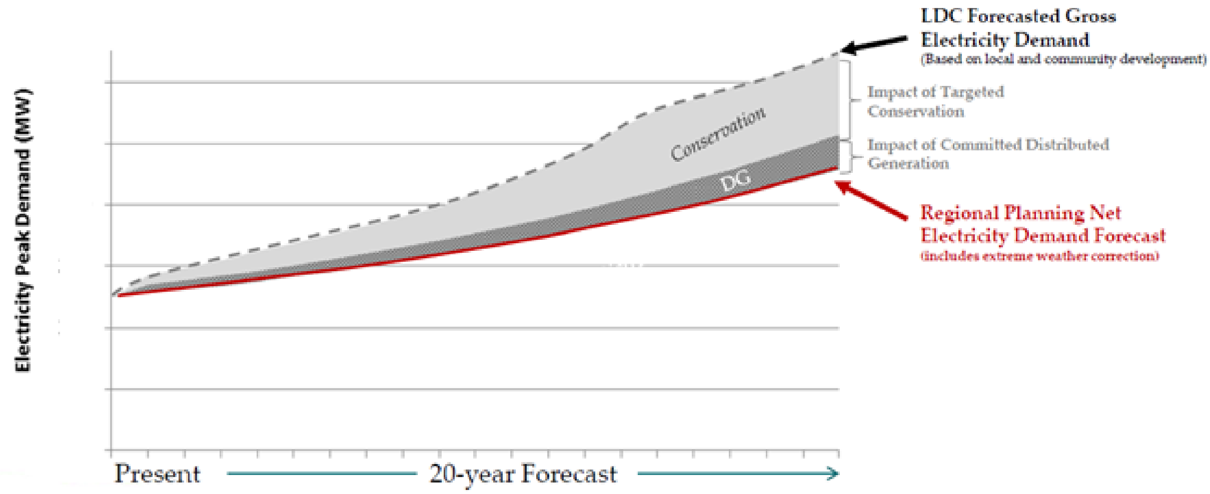
5.1 Methodology for Preparing the Forecast

A 20-year coincident peak demand forecast was developed for the region to assess its reliability needs. The steps taken to develop this forecast are illustratively shown in Figure 5.2 and described below.

1. The IESO weather-corrected the most recent year's demand data (2018 at the time of forecast development) to create a forecast "start" point based on expected peak demand under median (or "most likely") weather conditions. This "start" point was provided to the LDCs to help inform the basis of their forecasts.
2. Each participating LDC developed its own 20-year demand forecast for each station in their service areas. Since LDCs have the closet relationship to customers, connection applicants, and municipalities and communities, they have a better understanding of future local load growth and drivers than the IESO. The IESO typically carries out load forecasting at the provincial level.
3. The IESO modified the LDC forecasts provided for each station to reflect extreme weather conditions and subtracted the estimated peak demand impacts of provincial conservation policy and committed DERs that may have been contracted through previous provincial programs such as the Feed-in Tariff (FIT) and microFIT programs.

The result of these steps was a station-by-station outlook of net annual peak demand over the study period. Additional details on the demand forecast process, including station-level forecasts, may be found in Appendix B.

Figure 5.1 | Illustrative Development of Net Demand Forecasts



5.1.1 Conservation Assumptions in the Forecast

Conservation is achieved through a mix of program-related activities and mandated efficiencies from building codes and equipment standards. Future CDM savings for the ELS Region have been applied to the peak gross demand forecast and take into account both policy-driven and funded EE through the provincial Interim Framework, which came into effect on April 1, 2019 (estimated peak demand impacts due to program delivery to the end of 2020). The Interim Framework has targets to achieve annual energy savings of 1.4 TWh and peak demand reductions of 189 MW.[2] Expected peak demand impacts due to building codes and equipment standards were also included for the duration of the forecast.

Once sectoral gross forecast demand at each TS was estimated, peak-demand savings were estimated for each conservation category – building codes and equipment standards, and delivery of funded CDM programs. Due to the unique characteristics and available data associated with each category, estimated savings were determined separately. The total conservation savings included in the net demand forecast are provided in Table 5.1.1 below. These savings are broken down by residential, commercial and industrial customer sectors.

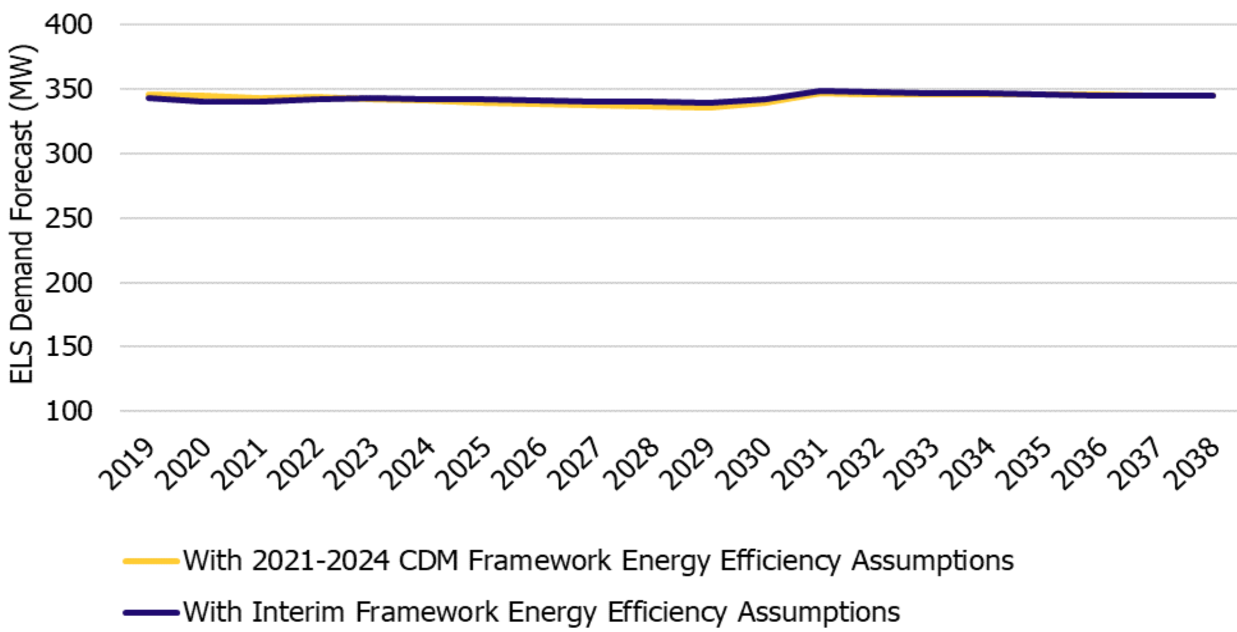
Table 5.1.1 | Peak Demand Savings due to Codes and Standards and Funded CDM Programs (MW)

Year	2020	2025	2030	2038
Residential	0.6	0.9	2.7	5.3
Commercial	3.8	2.4	1.1	0.4
Industrial	0.0	0.0	0.0	0.0
Total	4.5	3.3	3.8	5.7

[2] https://www.ieso.ca/en/Sector-Participants/Energy-Efficiency/2021-2024-Conservation-and-Demand-Management-Framework

After the demand forecast was developed for the ELS IRRP, the new 2021-2024 CDM framework starting in January 2021 was announced. While the Interim Framework assumptions were used in the development of the planning forecast, a sensitivity using the assumptions of the 2021-2024 CDM Framework was conducted. This sensitivity showed minimum impact (less than 2% difference) to the region's demand forecast as shown in Figure 5.1.1.

Figure 5.1.1| Comparison of Planning Demand Forecast with Interim Framework Energy Efficiency Assumptions vs 2021-2024 CDM Framework Energy Efficiency Assumptions



5.1.2 Distributed Energy Resources Assumptions in the Forecast

After applying the conservation savings to the gross demand forecast as described above, the forecast is further reduced by the expected peak contribution of existing and contracted DERs in the area. The peak demand impact of DERs that were connected to the system at the time of forecast development were accounted for in the IRRP. Given the difficulty of predicting future DER uptake, no assumptions have been made regarding future DER growth.

While the FIT Program and other procurements for small-scale generation have ended, the IESO remains committed to transitioning to the long-term use of competitive mechanisms to meet Ontario's resource adequacy needs through the Resource Adequacy Framework. In addition, the IESO is engaged in several activities to help reduce the barriers to DERs as alternatives to wires-based solutions. Additional details of these activities are included in the IESO's Regional Planning Process Review Report.

Based on the IESO contract list as of March, 2019, DERs in the ELS region are expected to offset demand by 14.6 MW of winter effective capacity at the start of the study period. As the DER contracts expire over the planning period, their contribution is removed accordingly. The DERs included in this IRRP are distribution connected from the following stations:

- Echo River TS
- Batchawana TS
- Goulais Bay TS
- Patrick St TS
- St. Mary's MTS
- Tarentorus MTS
- Chapleau DS
- DA Watson TS

Peak contribution factors reflecting the portion of installed capacity available at the time of peak were calculated for the DERs in the region using historical hourly generation where available; these factors are shown in Table 5.1.2 below.

Table 5.1.2| Peak Contribution Factors (%)

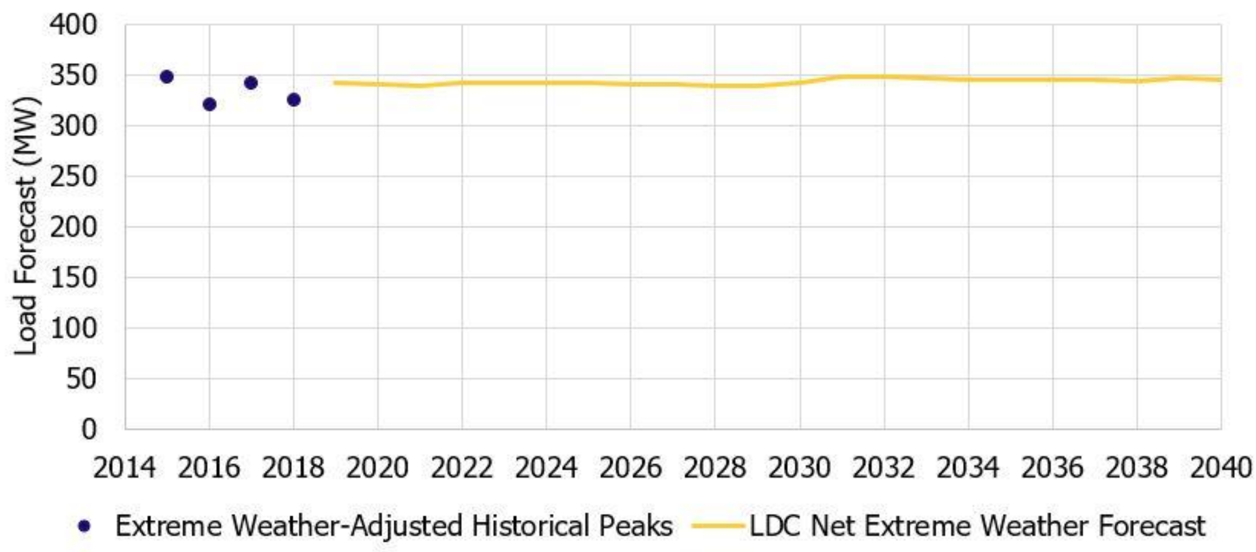
Fuel Type / Facility	Summer Contribution (%)	Winter Contribution (%)
Solar[3]	69	19
Algoma CHP	91	83
Chapleau Co-gen	72	53

5.1.3 Final Planning Forecast

The final net annual peak demand forecast developed for the IRRP is shown in Figure 5.1.3 and was used to carry out system studies that resulted in identifying the region's needs. As shown, the forecasted demand in the ELS Region is expected to remain relatively flat over the study period with a peak of 348 MW in 2031. This forecast includes distribution load plus existing industrial loads; it does not include a high industrial growth or expansion scenario, which will be considered as part of the IESO's bulk planning study in 2021 given the impact to the bulk transmission network in the broader region.

[3] The contribution factors for solar is based on actual summer and winter output from solar DG facilities connected to SSM PUC from 2016 to 2018. These represent the largest distribution connected solar facilities in the region.

Figure 5.1.3 |LDC Net Extreme Weather Forecast

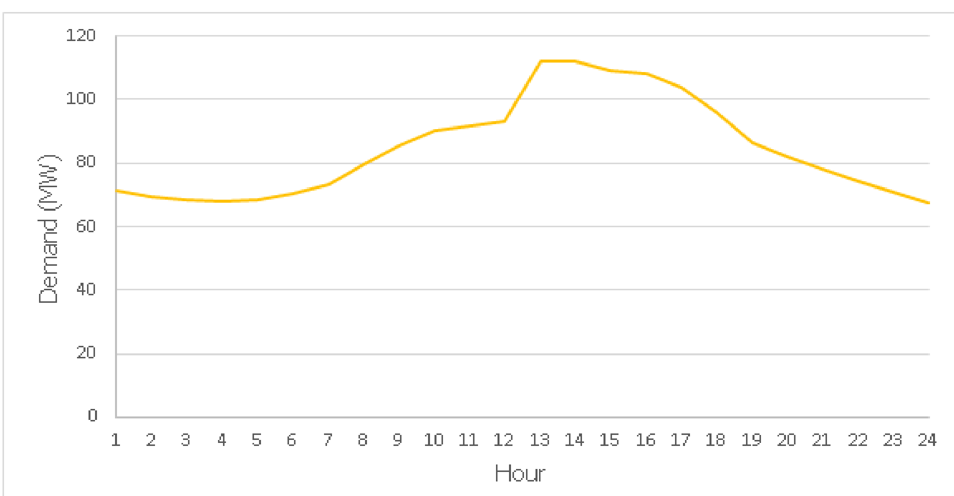


5.2 Load Duration Forecast (Load Profile)

In addition to the planning forecast developed for the purposes of identifying system needs, a load duration forecast was developed to further characterize the needs. Ultimately, the load duration forecast enables evaluation of the suitability of certain solution types to meet the area's magnitude, frequency and duration of needs. Using historical hourly duration information, a sample 8,760-hour profile was created and scaled such that the peak hour would align with the peak demand forecast in a given year of the planning horizon.

A sample of a typical peak-day profile for St. Mary's MTS and Tarentorus MTS is shown in Figure 5.2.

Figure 5.2| St. Mary's MTS and Tarentorus MTS on January 19, 2040

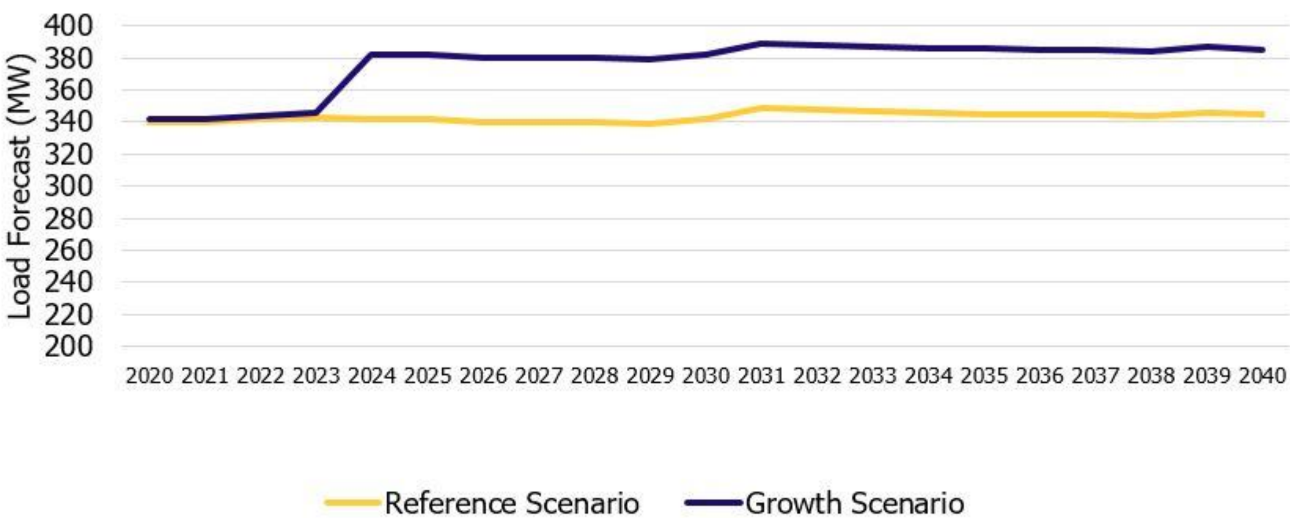


Additional details on the development of the load duration profiles are available in Appendix B.

5.3 Planning Forecast Sensitivity

In addition to the reference planning forecast, some of the LDCs also provided an incremental growth scenario. The reference forecast accounts for annual trend line growth which in the ELS region is fairly flat, when not considering high industrial growth, as seen in Figure 5.3. The incremental growth scenario takes into account large customer expansions and new potential customers that were uncertain at the time of forecast creation, 2% buffer for consideration of electric vehicles, customer expansions and new customers. These scenarios were taken into account in assessing the ELS region's needs and were studied as a sensitivity for the worst-case scenarios identified in the technical studies identified in Appendix D. The sensitivity results did not give rise to any new needs but did exacerbate existing needs in the area. Figure 5.3 shows the comparison between the reference planning demand forecast and the growth scenario. Note that this sensitivity does not capture the high industrial load growth that will be considered in the IESO's bulk planning study.

Figure 5.3| Comparison Between Reference and Growth Scenario



6. Electricity System Needs

Based on the demand forecast, system assumptions and application of planning criteria, the Technical Working Group identified electricity needs for this region over the current planning period from 2020 to 2040. This section summarizes the needs identified for the ELS region. For practical purposes, not every forecast year is assessed. Year 1 (2020) is assessed to represent the present-day regional power system, Year 5 (2025) is assessed to represent the near-term planning horizon, Year 10 (2030) is assessed to represent the medium-term planning horizon, and Year 20 (2040) is assessed to represent the long-term planning horizon.

These needs are categorized in four groups in accordance with ORTAC and NERC criteria: step-down station capacity, system capacity and performance, load security and load restoration.

6.1 Step-Down Station Capacity Needs

Step-down transformer stations convert high-voltage electricity from the transmission system to lower-voltage electricity for delivery through the distribution system to end-use customers. Each station is capable of converting a certain amount of power on a continuous basis and a slightly higher amount of power for a short duration, typically 10 days, which is referred to as its Limited Time Rating (LTR). Loading a station beyond this amount is not permissible except in emergency conditions, as it lowers the life expectancy of facility equipment and can impact reliability for customers.

Step-down station capacity needs are determined by comparing the non-coincident station peak demand forecast to the facility's 10-day LTR. When a step-down station's capacity is reached, options for addressing the need include reducing peak demand in the supply area (e.g., through EE or DERs), or building new step-down transformer capacity to serve incremental growth.

Table 6.1 shows that there are no transformer capacity limitations for the ELS region in the planning forecast for planning years 2020, 2025, 2030 and 2040.

Table 6.1 | Step-down Station Capacity Needs

Station	Continuous Rating (MVA)	10-day LTR Rating (MVA)	2020 (MW)	2025 (MW)	2030 (MW)	2040 (MW)
Andrews TS	5.0	5.0	0.22	0.22	0.22	0.22
Batchawana TS	4.3	4.3	1.64	1.72	1.78	1.92
DA Watson TS	75.0	97.5	8.47	8.76	9.01	9.51
Echo River TS	25.0	25.0	14.05	14.46	14.79	15.61

Station	Continuous Rating (MVA)	10-day LTR Rating (MVA)	2020 (MW)	2025 (MW)	2030 (MW)	2040 (MW)
Goulais Bay TS	15.0	15.0	8.46	8.75	8.99	9.47
Limer TS (proposed TS)	TBD	TBD	37.0	54.0	56.0	56.0
MacKay TS	0.5	0.5	0.04	0.04	0.04	0.04
Northern Avenue TS	5.0	5.0	2.48	2.56	2.64	2.78
Chapleau DS	17.05	17.05	6.37	9.62	10.07	11.32
Chapleau MTS	10	10	4.31	4.68	4.37	4.29
St. Mary's+ Tarentorus MTS	210	210	116.11	112.30	111.09	112.21

6.2 System Capacity and Performance Needs

System capacity refers to the amount of power that can be supplied by the regional transmission network, either by bringing power in from other parts of the province, or by generating it locally.

System capacity is assessed by modelling power flows throughout the local grid under anticipated coincident peak demand conditions, and applying a series of standard contingencies (outage events) as prescribed by ORTAC and NERC. Performance standards and criteria dictate how well the system must be able to operate following these contingencies. Standards at risk of not being met are identified as a system need. System performance before or following a disturbance must meet criteria identified in ORTAC section 4 and NERC standard TPL-001.

As with station capacity needs, system capacity needs can be addressed by upgrading the system to increase LMC, or addressed/deferred by reducing peak demand. Details on identified system capacity needs are described in the following sections.

6.2.1 Third Line Autotransformer Approaching Capacity

Third Line TS is a key supply point in the ELS region and consists of two 230/115 kV, 150/200/250 MVA autotransformers. The Third Line TS 230 kV station yard is supplied by circuits K24G extending to Mackay TS and P21G/P22G extending east to Mississagi TS. The Third line TS 115 kV station yard supplies multiple load stations via Algoma No. 1, No. 2, No. 3 circuits, Sault No.3 circuit and Northern Avenue Line circuit. It also supplies the loads at St. Mary's and Tarentorus stations via 115 kV circuits GL1SM GL2SM, GL1TA, and GL2TA.

When one of the Third Line autotransformers is lost, the loading of the companion autotransformer approaches its 10-day LTR today. This was also identified in the Needs Assessment and the Scoping Assessment. The loading on the companion transformer would be reduced modestly beyond 2023 when the Sault No.3 circuit returns to a network (non-radial) configuration. Sault No.3 is a 115 kV transmission circuit that runs from MacKay TS 115 kV station yard to Third Line TS 115 kV station yard. This circuit is currently de-rated due to deteriorating condition of the overhead conductor and operated normally-open at the Mackay TS terminal. Hydro One is currently planning to refurbish the circuit like-for-like as part of its planned sustainment activities to restore it to non-radial operation. The refurbished circuit is expected to be in-service by 2023.

This is not a firm need as there is no existing violations but this is flagged because loading on Third Line autotransformers is close to its LTR rating and should continue to be monitored. As mentioned in the Need Assessment, one of the Third Line autotransformers is scheduled to be replaced by 2025. However, the replacement autotransformer would not add any significant supply capacity to this region due to the ratings of a standard 230/115 kV autotransformer.

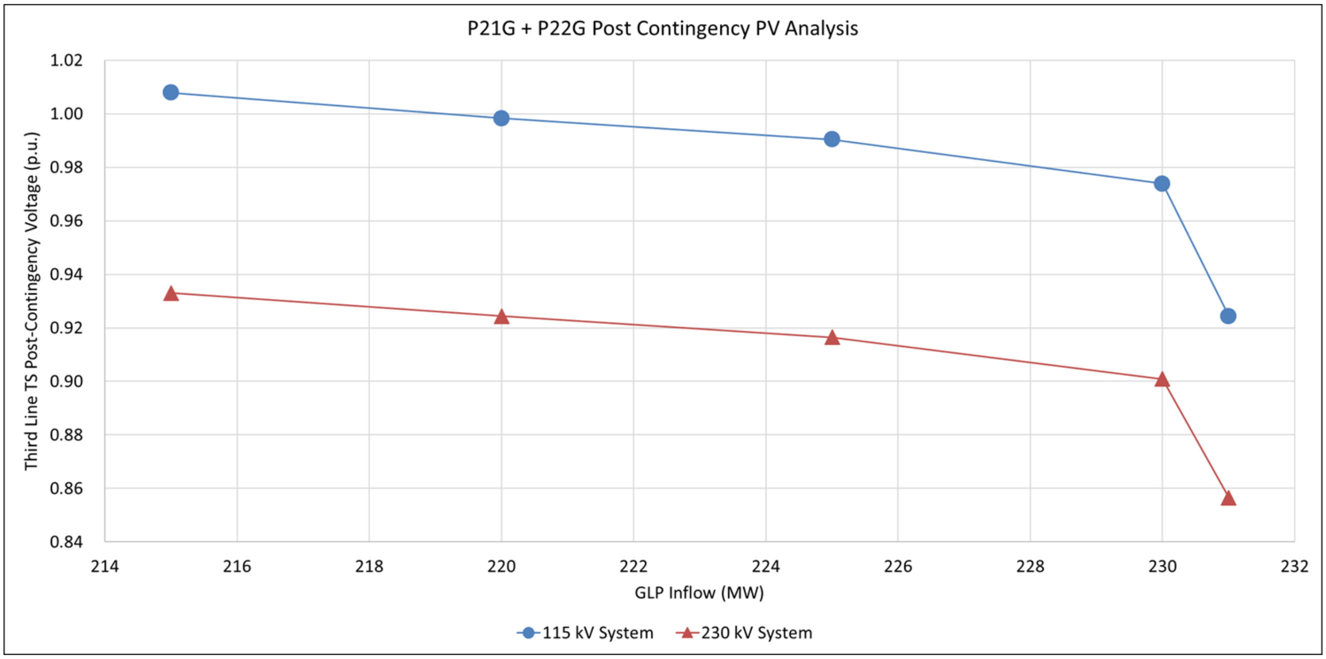
6.2.2 Voltage Concern Following the Loss of P21G/P22G

P21G and P22G are 230 kV circuits running from Third Line TS to Mississagi TS. These circuits form a critical supply path to the ELS region. A double circuit loss of P21G and P22G would cause voltage drop in excess of 10% (voltage collapse) at Third Line TS and other ELS stations throughout the planning period. This loss can be caused by an outage to the first circuit, followed by a contingency to the second or by a simultaneous loss of both circuits due to a contingency involving adjacent circuits on a common tower. Loss of P21G and P22G takes Third Line autotransformer T1 out of service by configuration. The voltage instability point is reached when GLP Inflow exceeds 230 MW and the circuits are out of service. [4] This is an existing issue today.

Third Line TS is equipped with Instantaneous Load Rejection Scheme with six load blocks to select for load shedding. Currently there is no provision in this scheme to allow remote arming of load rejection for the P21G+P22G double contingency. The IESO has to manually request Hydro One Sault Ste. Marie to arm certain amounts of load for rejection, and Hydro One Sault Ste. Marie prioritizes selection of the load blocks. The existing scheme has a provision to remotely arm load for this contingency, which would remove the need to initiate the manual procedure and hence, make the arming procedure more efficient.

[4] GLP Inflow is a system interface defined by the MW flow west at Mississagi TS on P21G and P22G circuits plus MW flow into Third Line TS on K24G circuit.

Figure 6.2.2| P21G + P22G Post Contingency PV Analysis



6.2.3 Capacity Overload of 115 kV Circuit No. 1 Algoma

A failure of breaker (BKF) 214 to operate at Patrick St TS will cause the loss of No. 2 Algoma and No. 3 Algoma circuits from Third Line TS to Patrick St TS. This results in thermal overload of the remaining No. 1 Algoma circuit beyond its short-term emergency (STE) rating during peak loads at Patrick St TS; note that No. 1 Algoma is the lowest rated circuit out of the three. This thermal overload of No. 1 Algoma can also occur with one of the Algoma circuits initially out of service, followed by the loss of another Algoma circuit.

This is an existing issue and thus an immediate need which was also identified in the Needs Assessment and Scoping Assessment. This is currently mitigated by the Patrick St TS manual load shedding scheme under which load is curtailed manually at Patrick St TS following the loss of one of the Algoma line circuits. This is done to prevent overloading of the No. 1 Algoma circuit in case the second circuit is also lost. Since this scheme is manual, load has to be shed before the actual contingency of the second circuit has taken place which is an event that may not occur. This scheme was designed as an interim solution until a more permanent solution was implemented.

6.2.4 Capacity Overload of 115 kV Circuit Sault No.3

During an outage to either the P25W or P26W circuit between Wawa TS to Mississagi TS, a contingency on the K24G circuit between Third Line TS and Mackay TS results in the thermal overload of the Sault No.3 circuit beyond its STE ratings starting in 2023 when Sault No.3 circuit is connected in a network configuration.[5] This phenomenon is a result of high East West Transfer (EWT) flows and losing two circuits that carry that flow.[6]

In addition, when one of the Third Line TS autotransformers is out of service, a normally operated Sault No.3 circuit (after its proposed upgrades) helps to alleviate overloading of the companion Third

[5] Sault No.3 circuit is being refurbished as part of a sustainment project

[6] EWT is defined as the MW flow at Wawa TS on circuits W21M and W22M.

Line TS autotransformer. However, if the second autotransformer is also lost, Sault No.3 circuit will be overloaded beyond its STE rating and causes a significant voltage decline in the 115kV area served by Third Line TS.

6.2.5 Anjigami T1/Hollingsworth T1 and T2 overload

Anjigami TS is connected to Wawa TS, Magpie TS, D. A. Watson and Hollingsworth TS. For loss of Anjigami TS, there is an overload on Hollingsworth T1 and T2, and vice versa based on the latest load forecast submitted by the LDC. This is consistent with 2014 Needs Assessment report finding that identified overloading on Hollingsworth TS – Transformer T2 / Anjigami TS – Transformer T1 due to load increases on the 44 kV system. HOSSM is working with the impacted LDC and proposed a solution of building a new 115/44 kV station, with a proposed named Limer TS (subject to change) that will tap off Hollingsworth 115 kV circuit to handle the load increase.

6.2.6 Bulk Area Needs

There is a potential for significant growth in industrial load in the ELS region over the planning period which would have a material impact on the bulk transmission system in the broader region. This growth will be considered as part of the IESO's bulk planning study which will commence in 2021.

Based on the reference load forecast included in this IRRP, the following bulk system need was identified and will be further considered as part of the bulk planning study described above. Following the loss of one of the 230 KV circuits, P25W or P26W circuits from Mississagi TS to Wawa TS, the companion circuit becomes loaded beyond its LTR rating under high westward power flow on the EWT.

6.3 Load Security Needs

The load security criteria in ORTAC Section 7.1 describes the maximum amount of load that can be interrupted following specified contingencies. A summary of the load security criteria can be found in Table 6.3. The load security criteria are met in the planning timeframe for the ELS region.

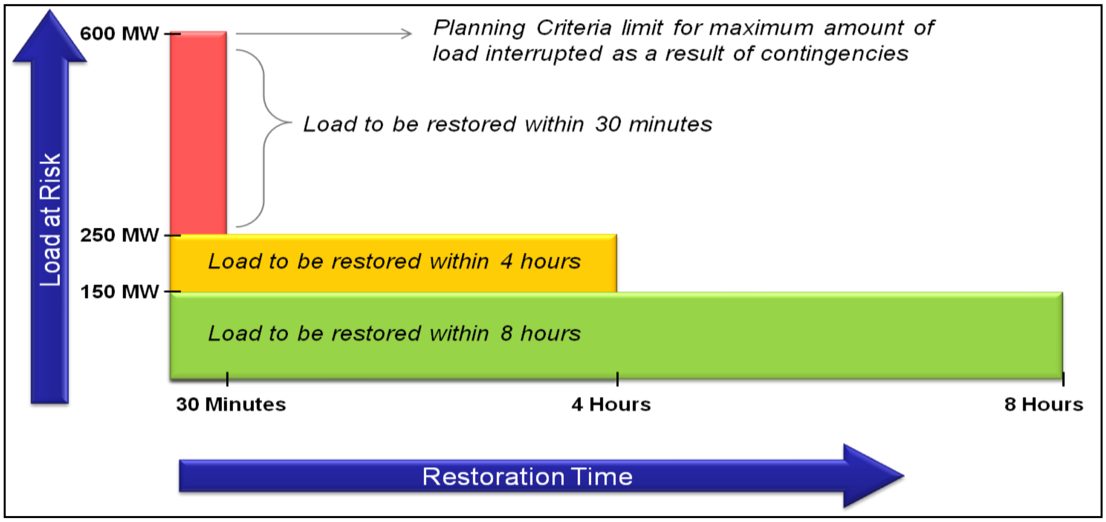
Table 6.3| Load Security Criteria

Number of Transmission elements o/s	Local Generation Outage	Amount of load allowed to be interrupted by configuration	Amount of load allowed to be interrupted by load rejection or curtailment	Total amount of load allowed to be interrupted
One	No	≤ 150 MW	None	≤ 150 MW
One	Yes	≤ 150 MW	≤ 150 MW	≤ 150 MW
Two	No	≤ 600 MW	≤ 150 MW	≤ 600 MW
Two	Yes	≤ 600 MW	≤ 600 MW	≤ 600 MW

6.4 Load Restoration Needs

As described in Section 7.2 of ORTAC, load restoration criteria specify the maximum amount of time it can take to restore interrupted load. A visual representation of ORTAC's load restoration criteria is shown in Figure 6.4.

Figure 6.4 | Load Restoration Criteria



6.5 Summary of Identified Needs

Table 6.5 below summarizes the electric power system needs identified in the ELS region in this IRRP. All of the needs exist today or arise in the near term. Note that the Anjigami T1/Hollingsworth T1 and T2 overload is customer driven. Section 7 considers different options to meet these needs and ultimately makes recommendations on how to address them.

Table 6.5 | Summary of Needs in the ELS Region

Need	Need Date
Loss of one Third Line TS autotransformer causes the companion transformer to be loaded close to its capacity	This is not a need, but flagged for ongoing monitoring
Loss of P21G and P22G circuits causes voltage collapse at Third Line TS. Enabling remote arming of GLP Instantaneous Load Rejection Scheme will drive operational efficiencies	Immediate
Loss of two Algoma circuits or a Patrick St TS 214 BKF results in thermal overload of the remaining Algoma circuit	Immediate
During an outage of P25W or P26W circuits, a loss of the K24G circuit results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	2023

Need	Need Date
During an outage of one of the Third Line TS autotransformers, a loss of the companion autotransformer results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	2023
For loss of Anjigami TS, there is an overload on Hollingsworth T1 and T2, and vice versa	2024

7. Plan Options and Recommendations

This section describes and evaluates the options considered to address system needs in the ELS region. This includes an evaluation of each option and the recommendations for action.

7.1 Alternatives for Meeting Needs

This section outlines the options considered to address the needs identified in the ELS Region, including how these options were evaluated and the recommendations for action in the near term.

There are generally two types of approaches for addressing electricity needs in regional areas:

- Target measures to reduce peak demand to maintain loading within the system's existing limits largely through the use of EE, and other demand management strategies.
- Build new infrastructure to increase the LMC of the area.

DERs, including DR, EE measures, or energy storage are all well suited to the first approach.

Even if not being pursued to address specific system capacity needs, there are other potential benefits to non-wires investments, such as customer cost savings, and reducing GHG emissions. Some of these other objectives have been identified in the City of Sault Ste. Marie's Greenhouse Gas Emissions Reduction Plan.

Where reducing peak demand is not technically or economically feasible through the use of DERs, the other strategy is to upgrade the infrastructure to increase the LMC of the area. In cases where a step-down station exceeds its maximum capacity, the station can be expanded. If the transmission system is at its capacity, generally the options are to build new local generation (to reduce the amount of power that needs to be brought in from elsewhere), or build new or upgrade the existing transmission infrastructure to increase transfer capability. New remedial action schemes can also be introduced when transmission upgrades are not considered feasible at this time. These schemes can act to reduce load and/or generation to meet identified transmission system needs.

Each of these categories of options are further explored below as they relate to the needs in the ELS region.

7.1.1 Conservation

Conservation is important in managing demand in Ontario and plays a key role in maximizing the utilization of existing infrastructure and maintaining a reliable supply of electricity. Conservation is achieved through a mix of program-related activities including behavioural changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results.

On September 30, 2020 the IESO received a Ministerial directive to implement a new 2021-2024 CDM Framework. As discussed in Section 5.1.1., although the information about the new CDM Framework was not available when the forecast was being developed, continued program-driven CDM savings were included in the forecast consistent with the levels of the previous Interim Framework. The difference between these levels of expected savings is marginal. The new CDM Framework will contribute to lowering the net demand as seen on the transmission system; however, estimations of the savings in the area show that the identified needs still exist after these savings are accounted for.

Conservation expected to be achieved through time-of-use and codes and standards has already been included in the planning forecast scenarios.

While there is the potential for additional savings from CDM activities, beyond the levels assumed in the load forecast, these options were not investigated further at this time because the size of the need represents more than 66% of the winter peak demand of the ELS area. CDM programs tend to be more feasible and cost effective when the need represents much small percentage of the total system load (e.g., 2%).

For this reason, additional CDM activities were not considered further to address the immediate needs identified.

7.1.2 Local Generation

Local generation options were also considered to address the identified needs. A local generator, sited in the 115 kV system, could technically meet the reliability needs of the ELS region. The facility would need to be sized to deliver approximately 65 MW of winter peak capacity, when considering approximately 11 MW contribution from existing demand response in the region. In addition, the generation solution would have to address the annual energy requirements seen in Table 7.1.2 below. Based on these need characteristics, the NPV of a new combined cycle gas turbine (CCGT) generator was evaluated and estimated at $250 million, which includes capital costs, operating costs and credit for system capacity value to the broader system (as dictated by provincial needs and zonal capacity limitations). Based on economic analysis of available technology, the CCGT generator option is the cheapest utility scale non-transmission alternative. Given the cost of this option compared to those of the transmission options, this alternative was ruled out.

Table 7.1.2|Energy Required to Address Reliability Needs at Third Line TS

	2020	2025	2030	2035	2040
Annual Energy Need (MWh)	224,000	196,000	168,000	153,000	122,000

7.1.3 Transmission

A number of transmission and distribution, or "wires," solutions were considered by the Technical Working Group to meet the near-term needs. "Wires" infrastructure solutions can refer to new or upgraded transmission or distribution system assets, including circuits, stations, or related equipment, and remedial action schemes.

The following remedial action schemes were considered by the Working Group to meet the system capacity and performance needs in the near term.

Enable Remote Arming for P21G+P22G in GLP Instantaneous Load Rejection Scheme

There is an existing RAS called the GLP Instantaneous Load Rejection Scheme that is initiated for the loss of both Third Line autotransformers or the loss of both P21G and P22G circuits. At present, a request has to be made to Hydro One Control Room to enable the scheme for the loss of P21G and P22G double contingency. It is a manual process where IESO Control Room has to call Hydro One Control Room and Hydro One arms the load. This scheme has a setting, which once enabled will allow IESO Control Room to arm load remotely, thus eliminating the need for the manual arming sequence and making the load rejection arming procedure more efficient. It would cost the transmitter approximately $50,000 to enable the remote arming setting in the RAS. Part of the change will require relevant Facility Description Document (FDD) and IESO System Control Order (SCO) documentation to be updated.

Automate Patrick St TS Manual Load Shedding Scheme

There is an existing Patrick St TS Manual load shedding scheme designed to manage the load at Patrick St TS. Loads at Patrick St TS are normally supplied by the three 115 kV Algoma circuits and from Clergue GS and load displacement generators at Algoma Steel Inc. Following contingencies that leave only one Algoma circuit in service, manual load shedding may be required. Since this process is not instantaneous, it also exposes the remaining Algoma circuit to an extremely high flow if the second circuit was to trip during the manual load shedding sequence. This scheme was originally designed as an interim solution until a more permanent solution was employed.

ORTAC provisions allow for planned load rejection up to 150 MW for any two elements out of service; however, a load shedding scheme would need to be automatic and allow load rejection of Patrick St TS load upon the loss of an Algoma circuit when another Algoma circuit is out of service. This solution would cost approximately $2 Million. This scheme can be expanded to arm load for the Patrick St TS 214 BKF.

Control Actions and System Reconfiguration for Overloading of Sault No.3

An operational control action such as opening Sault No.3 circuit between Sault Ste. Marie and the Mackay sub-system could be implemented when there is an outage to one of the 230 kV circuits P25W or P26W to avoid post-contingency overloading on the 115 kV Sault No.3 circuit. This would address the need on the Sault No.3 circuit but would also overload the companion 230 kV PxW circuit during high flows on the East West Tie.

During an outage to one of the Third Line TS autotransformers, Sault No.3 can become overloaded if the remaining autotransformer is also lost due to a contingency. The loads served by Third Line TS will also suffer a voltage decline beyond that permissible via ORTAC. To prevent these phenomena, one solution is to reject load; however, studies show that during peak demand conditions, more than 150 MW of load shedding may be required which violates ORTAC. Another potential solution is to reconfigure the system following the loss of the second transformer during peak conditions, however, this could similarly result in significant amounts of load lost by configuration.

Given that these needs involve facilities that will be considered in the IESO’s 2021 bulk plan, they will be provided as input into the bulk planning study and the solutions to address them will be coordinated with the outcomes of the bulk planning study.

7.2 Recommended Plan to Address Local Needs

To meet identified electricity needs in the ELS region, the Technical Working Group recommends the implementation of the following actions:

Monitor Demand Growth and Supply in the Region

The Technical Working Group recommends closely monitoring demand growth and supply in the ELS region to determine if and when additional transformation capacity at Third Line TS is required. This includes monitoring the city of Sault Ste. Marie's climate plans, described further below, as they may have an effect on the demand.

The city of Sault Ste. Marie is planning on increasing community and corporate climate change initiatives through their community Green Gas Emissions Reduction Plan.[7] This plan sets out the actions required on a short, medium and long-term basis in order to reduce GHG emissions in the city of Sault Ste. Marie. The goal is for the city of Sault Ste. Marie to reduce their GHG emissions and be net zero by 2050. Actions have been broken down by sector which includes Buildings & Energy at a community level. The GHG reduction plan in the Buildings & Energy sector includes:

- Increase uptake in residential and commercial energy efficiency retrofits that reduce the use of fossil fuels;
- Increase the number of new homes and business builds to incorporate energy efficient equipment (e.g., new furnaces, weather stripping, efficient lighting, etc.);
- Research policies for efficient new builds that go above the Ontario Building Code;
- Develop a community energy efficiency retrofit program (either for energy efficiency retrofits or renewable energy); and
- Encourage the use of energy reduction devices such as thermal imaging heat devices.

These activities also have the potential to reduce electricity demand in the city of Sault Ste. Marie and are therefore important considerations as part of regional planning. The Working Group will continue to monitor implementation of these recommendations and their impact on the demand.

The Technical Working Group encourages potential new customers in the ELS Region to notify the IESO, HOSSM and their appropriate LDC of their growth or connection plans as soon as possible such that this growth can be reflected in ongoing planning in the region. If required, the next round of regional planning can be initiated early, i.e., before 5 years, should the demand follow the alternate growth scenario as described in section 5. The IESO will also continue to monitor potential non wires alternatives and implementation options.

The overall demand forecast for the ELS region is relatively flat over the planning period but has potential for significant growth resulting from large industrial load projects and expansions. This will be studied as part of an IESO bulk planning study.

[7] https://saultstemarie.ca/City-Services/City-Departments/Community-Development-and-Enterprise-Services/FutureSSM/Greenhouse-Gas-Emissions-Reduction-Plan.aspx?fbclid=IwAR1JDdn5-ZwoXP4uIZnu3C9Y-lOS3IFJnBmXqlY1DWdyQiAVQHj4bgF3R6c

Enable Remote Arming for P21G+P22G in GLP Instantaneous Load Rejection Scheme

The Technical Working Group recommends that HOSSM modify the existing GLP Instantaneous Load Rejection Scheme as soon as practical. This scheme would allow remote arming of load rejection, within amounts permissible via ORTAC, during periods of high demand in case the transmission circuits supplying Sault Ste. Marie (P21G and P22G) are both out of service, and would result in operational efficiencies over manual arming. The likelihood of rejecting the load as a result of both transmission circuits being out of service is low but must be planned for as per planning standards. The approximate cost of expanding this scheme is $50K.

Implement Automatic Load Rejection Scheme at Patrick St TS

The Working Group recommends HOSSM to implement a new automatic load rejection scheme to arm up to 75 MW of load rejection automatically during periods of high demand in case the companion circuits to No. 1 Algoma circuit are both out of service. This would solve the thermal issues to the electricity supply within Sault Ste. Marie at an approximate cost of $2 Million.

Coordinate with IESO's Bulk Planning Study Regarding Sault No.3 Circuit Overloading

Given that the facilities driving the needs related to the overloading of the Sault No.3 circuit will be considered in the IESO's 2021 bulk plan, it is recommended that these needs be carried forward as an input to the bulk plan so as to ensure a coordinated approach with respect to the outcomes and solutions developed as part of the bulk plan.

New 115/44 kV Station

The Technical Working Group has been informed that HOSSM plans on building a new 115/44 kV station that will tap off the Hollingsworth 115 kV circuit and will serve the incremental customer driven load. This is in line with the recommendation made in the Needs Assessment; HOSSM will work with the local LDC and customers when sizing and designing the new station.

7.3 Implementation of Recommended Plan

To ensure the electricity needs of the ELS area are addressed, it is important that the recommendations are implemented in a timely manner. The specific actions and deliverables associated with the plan are outlined in Table 7.3 below, along with their recommended timing and the parties with lead responsibility for implementation. The ELS Working Group will continue to meet regularly during the implementation phase of this IRRP to monitor developments in the ELS region and to track progress of these deliverables.

Table 7.3 | Implementation of Recommended Plan for ELS Region

Need	Recommendation	Lead Responsibility	Required By
Loss of one Third Line TS autotransformer causes the companion autotransformer to be loaded close to its capacity	Monitor load and supply in the ELS region	IESO/HOSSM	Immediately and Ongoing
Loss of P21G and P22G circuits causes voltage collapse at Third Line TS and other ELS stations	Enable remote arming of GLP Instantaneous Load Rejection Scheme for P21G and P22G double contingency for operational efficiency over manual arming	Hydro One	Immediately
Loss of two Algoma circuits or a Patrick St TS 214 BKF results in thermal overload of the remaining Algoma circuit	Implement automatic load rejection scheme at Patrick St TS	HOSSM	Immediately
During an outage of P25W or P26W circuits, a loss of the K24G circuit results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	Consider as part of the IESO's Bulk Planning Study for the broader region commencing in 2021	IESO/HOSSM	2023
During an outage of one of the Third Line TS autotransformers, a loss of the companion autotransformer results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	Consider as part of the IESO's Bulk Planning Study for the broader region commencing in 2021	IESO/HOSSM	2023
For loss of Anjigami TS, there is an overload on Hollingsworth T1 and T2, and vice versa	Hydro One to work with the LDC to build a new 115/44 kV station that will tap off Hollingsworth 115 kV circuit to accommodate the load increase	HOSSM	2024

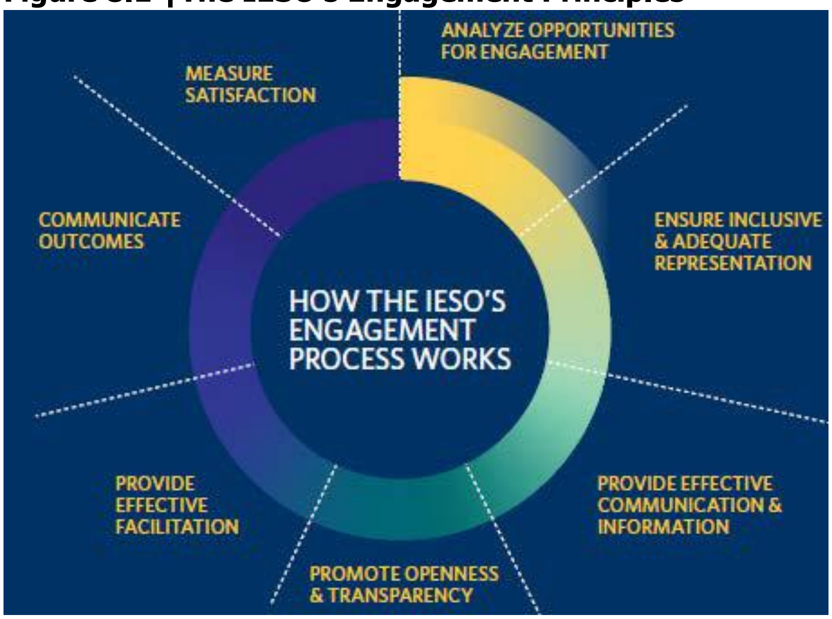
8. Engagement

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

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP. [8] The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 8.1 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for ELS

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

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[8] https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

Creating the engagement plan for this IRRP involved: [9]

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

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

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process[10]
- A dedicated section on the IESO's online engagement platform, IESO Connects, to provide an alternative mechanism for communities and interested parties to learn about the IRRP and offer any input[11]
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin
- Public webinars
- Face-to-face meetings
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (See section 1.4 Outreach with Municipalities)

8.3 Engage Early and Often

Preliminary discussions were held early in the planning process to gain an understanding of key local energy priorities and help inform the engagement approach for this planning cycle. These discussions were important to establish and build new relationships as this round of planning marked the first cycle requiring regional coordination and community engagement.

Formal engagement began with an invitation to targeted communities and those with an identified interest in regional issues to learn about and provide comments on the ELS Scoping Assessment Report before it was finalized. Following a public webinar and written comment period, the final Scoping Assessment was published in October 2019 with responses to feedback received, which identified the need for an IRRP for the ELS region.

Outreach then began with targeted communities to inform early discussions for the development of the IRRP including the IESO's approach to engagement. The launch of a broader engagement initiative followed with an invitation to subscribers of the ELS region to ensure that all interested parties were made aware of this opportunity for input.

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[9] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/els/East-Lake-Superior-IRRP-Engagement-Plan-20200514.ashx
[10] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Regional-Electricity-Planning-East-Lake-Superior
[11] https://iesoconnects.ca/content/electricity-planning-east-lake-superior

Three public webinars were held at major junctures during IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components. Both webinars received cross-representation of stakeholders and community representatives attending the webinar and submitting written feedback during a 15-day comment period.

The first webinar sought input on the draft engagement plan, the electricity demand forecast and needs. Comments received during the webinar were related to the underlying numbers, factors and assumptions in the demand forecast. As a result of this feedback, further clarification was provided in subsequent engagement events and materials.

The second webinar sought feedback on the defined electricity needs for the region and potential options. Comments received during the written feedback window touched on the following major themes that has been considered in the development of this IRRP:

- Options development, specifically the consideration on non-wires alternatives (NWAs)
- Consideration of high industrial growth potential
- Access to data and information to enable the market to respond to regional electricity needs

As a final step in the engagement initiative, the third public webinar was held to seek input on the analysis of options and draft IRRP recommendations. Comments were received around the potential for non-wires options, particularly energy storage, to meet regional electricity needs and clarification on the economic assessment of options. Non-wires options including generation and CDM were considered in the analysis of potential solutions, and as discussed during the third webinar, no specific actions are required at this time. The uptake of non-wires resources will be monitored as part of ongoing monitoring and planning for the ELS region.

Based on the discussions both through the ELS IRRP engagement initiative and the IESO's Regional Electricity Networks, it is clear that there is broad interest to further discuss the potential for alternative energy solutions in supporting future growth. [12] Ongoing discussions will continue through the IESO's Northeast Regional Electricity Network to keep communities and interested parties engaged on local developments, priorities and planning initiatives in preparation for the next planning cycle. [13]

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's ELS IRRP engagement web page.

8.4 Bringing Communities to the Table

The IESO held meetings with the City of Sault Ste. Marie, large industrial customers and energy service providers in the region to seek input on major planning and development projects and to ensure that local initiatives were taken into consideration in the development of this IRRP. These meetings helped to inform the region's electricity needs and provided opportunities to strengthen these relationships for ongoing dialogue beyond this IRRP process.

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[12] https://ieso.ca/en/Get-Involved/Regional-Planning/Electricity-Networks/Overview

[13] https://iesoconnects.ca/collections/northeast-regional-electricity-network

9. Conclusion

The ELS IRRP identifies electricity needs in the region over the 20-year period from 2020 to 2040, recommends a plan to address immediate and near-term needs, and identifies needs that are related to the bulk transmission system in the broader region that should be further considered as part of the IESO's bulk planning study for the region, commencing in 2021, to ensure a coordinated approach with respect to outcomes.

Specifically, the IRRP includes recommendations to monitor load growth and supply in the region, and implement remedial action schemes to ensure the reliability of the system supply within the region. The IRRP also recommends that the needs identified with respect to the overloading of the Sault No.3 circuit be considered as part of the IESO's bulk planning studies for the area in 2021 given that these facilities will also be considered in the bulk study.

Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the regional planning for the ELS region.

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

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