East Lake Superior Region Integrated Regional Resource Plan

Appendices

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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.

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

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 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 a 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.

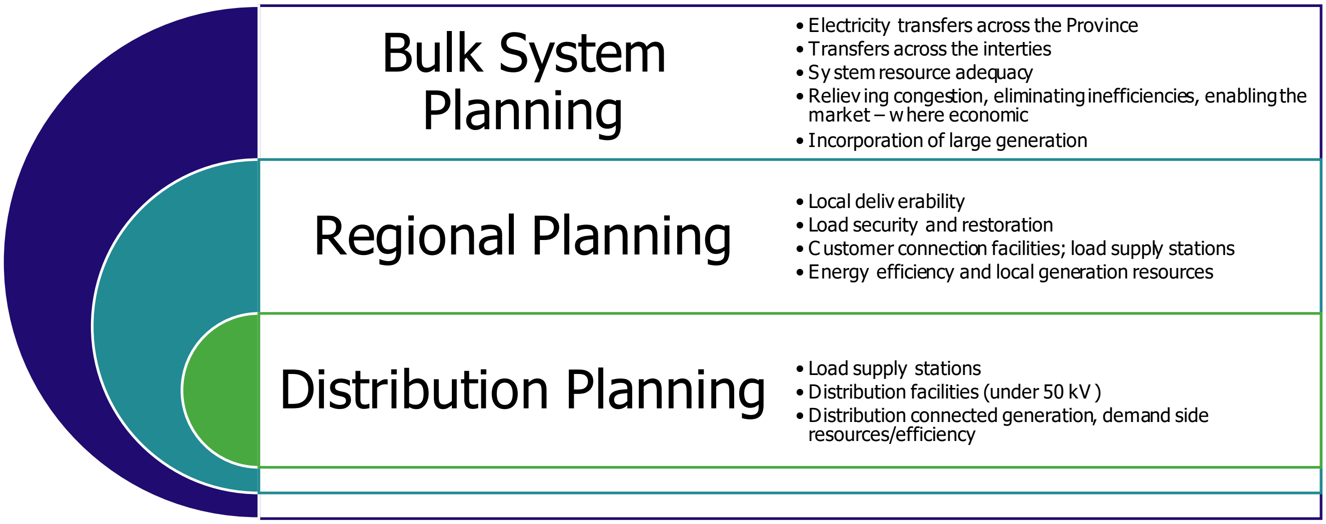
The final Needs Assessment Reports, Scoping Assessment Outcome Reports, IRRPs and RIPs are posted on the IESO's and the relevant transmitter's web sites, and may be referenced and submitted to the OEB as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. 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 A.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 A.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

This Appendix describes the methodologies used to develop the demand forecast (peak and duration) for the East Lake Superior (ELS) Region IRRP studies. Forward-looking estimates of electricity demand were provided by each of the participanting LDCs and informed by the forecast base year and starting point provided by the IESO. The sections that follow describe the method used by the IESO to determine the forecast starting point, the approaches and methods used by each LDC to forecast demand in their respective service area, the conservation and DG assumptions and the duration forecast methodology.

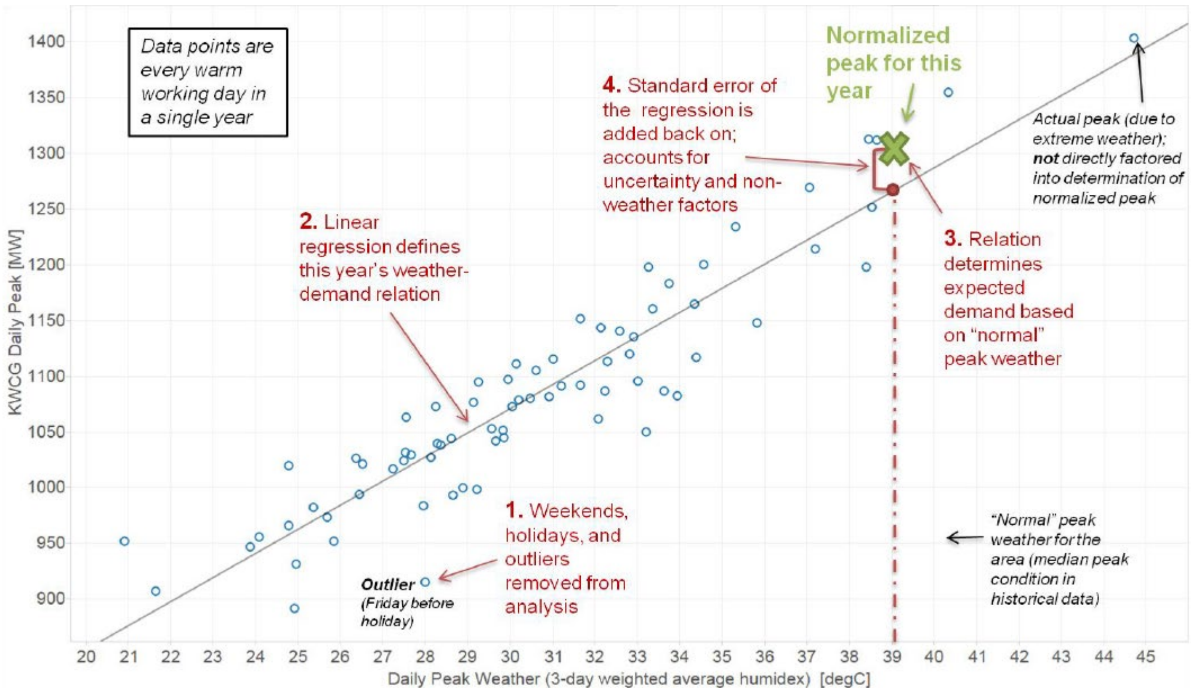
B.1 Method for Determining Forecast Starting Point

To develop a standardized starting point for the ELS region demand forecast, the following steps were performed:

- 5-year i.e., 2014-2018, historical non-coincident peak demand data was gathered for each station.
- Historical demand data was weather normalized to reflect median peak weather conditions at each station
- Historical output from Distributed Generation at the time of peak was added back to the historical demand for each year (because DG output is subtracted from the gross forecast).
- The starting point is typically selected using the most recent weather-corrected gross peak load; previous year's data points are used to observe trends and outliers.

In order to weather-normalize the data, historical demand was adjusted to reflect the median peak weather conditions for each transformer station in the area for all historical years. Median peak 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 exceed this peak, and a 50% chance that the actual peak demand will be lower than this peak. The methodological steps are described in Figure B-1; note that this is an illustrative example that was developed for a different region.

Figure B.1 | Method for Determining The Weather-Normalized Peak



The impact of Distributed Generation was then added to the median weather peak for all historical years and the most recent year (2018) was used as a starting point, for each LDC station. This data was provided to the LDCs to inform the starting point of their 20-year demand forecasts, which were developed using the their preferred methodology (described in Appendix B.2, below).

Once the LDC 20-year, median peak demand forecasts were provided to the IESO, the forecast was adjusted to reflect the impact of extreme weather conditions on electricity demand. The studies used to assess the reliability of the electric power system generally require 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 be reasonably expected to occur. Peaks that occur during extreme weather (e.g., winter polar vortexes) are generally when the electricity system infrastructure is most stressed. The extreme weather adjustment factors used in the ELS IRRP were calculated as per IESO's methodology for modelling extreme weather conditions, which determines the relationship between weather and demand for a given region in a given timeframe.

B.2 LDC Forecast Methodologies

This section describes the methodologies used by the participating LDCs to develop their planning forecasts. These include:

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

B.2.1 PUC Distribution Inc.

For its load forecast, PUC Distribution Inc. utilizes a regression analysis methodology that was approved by the OEB in its 2013 Cost of Service application and is used by multiple LDCs across the Province. PUC Distribution's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized forecast is developed based on a regression analysis that incorporates variables that impact PUC Distribution usage. Second, the weather normalized forecast is adjusted by a historical loss factor to produce a weather normalized billed forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast. The forecast of customers by rate class is determined using a geometric mean analysis and judgment of PUC Distribution. For those rate classes that use kW for the distribution volumetric billing determinant an adjustment factor is applied to the class energy forecast based on the historical relationship between kW and kWh. For further details, please refer to PUC Distribution's OEB IRM application EB-2017-0071 Exhibit 3.

Furthermore, PUC Distribution Inc. considers other supplemental factors derived through its routine planning processes as described in its Distribution System Plan, also filed with the OEB as part of its Cost of Service application. These include potential impacts to the load forecast determined through stakeholder consultations:

- Customer Engagement (residential surveys, large C&I plans, developers, DG and REG customers)
- Municipal Government Consultations (City budgets, official plans, economic development plans, population projections)

For the load forecast period considered in this regional planning report, these additional supplemental factors did not contribute materially to the forecast determined through the regression methodology.

B.2.2 Algoma Power Inc.

Algoma Power Inc. ("API") provides electricity distribution services in the remote areas of Northern Ontario located north and east of the City of Sault Ste. Marie. API serves approximately 12,000 customers on a distribution system consisting of 1,861 kilometers of distribution line. The distribution system extends 93 Km east and approximately 255 Km north of the City of Sault Ste. Marie.

API distributes electricity to widely dispersed residential, seasonal, commercial and industrial customers as well as remote First Nations communities. Organized townships are governed by 14 separate municipal governments and the seven First Nation reserve locations are governed by four First Nations. Apart from property owned by businesses or individuals, API's territory also consists of significant parcels owned by large resource-based companies or provincial parks.

API experiences its peak demand mostly within the winter months due to lack of natural gas heating, a high penetration of electric heating, and a relatively low penetration of central air conditioning in much of its service area. Variances in seasonal peaks are attributable to the varying weather conditions experienced in Northern Ontario.

API follows a trend load forecasting methodology, where future loads are extrapolated based on recent and past peak loads for each connected supply point. A baseline forecast is developed with consideration to normal operating conditions, coincident peak loading and extreme weather conditions. From the established baseline year, a predefined growth rate is applied, which typically accounts for average annual load growth increase, but also factors in known future municipal and industrial developments. Consideration is also given to market trends in potential electricity needs, such as the anticipated deployment of electric vehicles.

B.2.3 Hydro One Networks Distribution

Hydro One Distribution services the areas in East Lake Superior region that are not served by other LDCs through Chapleau DS. Hydro One Distribution used both the econometric and end-use forecasting to develop the 20-year forecast provided to IESO.

A baseline forecast (MW station peak in the 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 Chapleau DS.

From the established baseline year, a growth rate (%) was applied to station demand level to provide forecast values for Chapleau DS 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/sq.ft); and the need for large scale electrification projects.

Detailed information about load growth, based on local knowledge and relation between local and provincial load was used to augment the forecast values within the study period.

B.3 Conservation Assumptions in ELS Forecast

Conservation measures can reduce the electricity demand and their impact can be separated into the two main categories: Building Codes & Equipment Standards, and CDM Programs. The assumptions used for the ELS IRRP forecast take into account the conservation programs from the provincial Interim Framework. The savings for each category were estimated according to the forecast residential, commercial, and industrial gross demand. A top down approach was used to estimate peak demand savings from the provincial level, to the Northeast transmission zone and then allocated to ELS region. This section describes the process and methodology used to estimate conservation savings for the ELS Region and provides more detail on how the savings for the two categories were developed.

B.3.1 Estimate Savings from Building Codes and Equipment Standards

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 region, the associated peak demand savings for codes and standards were estimated for the Northeast zone and compared with the gross peak demand forecast in the zone.

From this comparison, annual peak reduction percentages were developed for the purpose of allocating the associated savings to each TS in the region.

Consistent with the gross demand forecast, 2018 is determined as the base year. New peak demand savings from codes and standards were estimated. The residential annual peak reduction percentages of each year were applied to the forecast residential demand at each TS to develop an estimate of peak demand impacts from codes and standards. By 2038, the residential sector in the region is expected to see about 4.0% peak demand savings through standards. The same is done for the commercial sector, which will see about 0.3% peak-demand savings through codes and standards by 2038. The sum of the savings associated with the two sectors are the total peak demand impact from codes and standards. There are no savings from codes and standards considered to be associated with the industrial sector.

B.3.2 Estimate Savings from Conservation Programs

In addition to codes and standards, the delivery of CDM programs reduces electricity demand. The impact of existing and committed CDM programs were analyzed, which take into account both policy-driven and funded CDM. These include the Conservation First Framework wind-down and the Interim Framework. While the new 2021-2024 Conservation and Demand Management (CDM) framework was not taken into account (as it was not in place at the time of forecast development), sensitivities were conducted to assess its impact as described in Section 5.1.1 of the IRRP. A top down approach was used to estimate the peak demand reduction due to the delivery of 2019 and 2020 programs, from provincial to Northeast to the TSs in the region. Persistence of the peak demand savings from energy efficiency programs were considered over the forecast period.

Similar to the estimation of peak demand savings from building codes and equipment standards, annual peak demand reduction percentages of program savings were developed by sector. The sectoral percentages were derived by comparing the forecasted peak demand savings with the corresponding gross forecasts in Northeast transmission zone. They were then applied to sectoral gross peak forecast of each TS in the region. By 2020, the residential sector in the region is expected to see about 0.2% peak demand savings through programs, while commercial sector and industrial sector will see about 2.2% and 1.0% peak reduction respectively. Those savings will decay over time as the energy efficiency measures come to the end of their effective useful lives.

B.3.3 Total Conservation Savings and Impact on the Planning Forecast

As described in the above sections, peak demand savings were estimated by sector. Winter peak demand savings by TS were summarized in Table B.3.3. The analyses were conducted under normal weather conditions and can be adjusted to reflect extreme weather conditions. The resulting forecast savings, along with the impact of distributed generation resources, were applied to gross demand to determine net peak demand for further planning analyses.

Table B.3.3 | Forecast of Expected Winter Peak Demand Savings (MW) Due to Codes and Standards and Funded CDM Programs - by Station

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
DA Watson TS	0.07	0.12	0.12	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.12	0.14	0.16	0.18	0.19	0.20	0.20	0.20	0.20
Echo River TS	0.11	0.20	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.18	0.20	0.24	0.27	0.30	0.32	0.33	0.34	0.34	0.34
Goulais Bay TS	0.07	0.12	0.12	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.12	0.14	0.16	0.18	0.19	0.20	0.20	0.20	0.20
Limer TS	0.11	0.19	0.19	0.19	0.15	0.15	0.15	0.15	0.15	0.15	0.17	0.19	0.23	0.25	0.28	0.30	0.32	0.32	0.32	0.32
Andrews TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mackay TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northern Av TS	0.02	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.05	0.05	0.06	0.06	0.06	0.06	0.06
Chapleau DS	0.07	0.12	0.12	0.12	0.10	0.10	0.10	0.10	0.10	0.10	0.12	0.13	0.16	0.18	0.20	0.22	0.23	0.23	0.23	0.23
Chapleau MTS	0.03	0.06	0.06	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.05	0.06	0.07	0.07	0.08	0.09	0.09	0.09	0.09	0.09
St. Mary's TS	0.91	1.58	1.54	1.54	1.16	1.16	1.13	1.12	1.12	1.08	1.17	1.29	1.46	1.60	1.76	1.87	1.93	1.91	1.88	1.86
Tarentorus TS	1.16	2.02	1.97	1.98	1.49	1.48	1.45	1.43	1.43	1.39	1.50	1.66	1.88	2.05	2.25	2.40	2.47	2.44	2.41	2.38
Total	**2.56**	**4.45**	**4.36**	**4.39**	**3.33**	**3.32**	**3.27**	**3.23**	**3.23**	**3.15**	**3.45**	**3.84**	**4.39**	**4.82**	**5.32**	**5.69**	**5.87**	**5.84**	**5.79**	**5.74**

B.4 Distributed Energy Resources Assumptions in ELS Forecast

Besides conservation savings, the expected peak contribution of existing and contracted DERs in the area were also taken into account.

Table B.4 | DER Forecast by Station

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DA Watson TS	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Echo River TS	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.16	0.12	0.08	0.02	0.01	0.00	0.00	0.00
Goulais Bay TS	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Limer TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Andrews TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mackay TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northern Av TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chapleau DS	2.65	2.65	2.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chapleau MTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
St. Mary's TS	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	0.23	0.18	0.16	0.16	0.16	0.14	0.00	0.00
Tarentorus TS	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	0.14	0.10	0.06	0.03	0.03	0.02	0.00	0.00	0.00

B.5 Final Peak Forecast by Station

After taking the median weather forecast provided by LDCs and applying the CDM assumptions above, forecasts were adjusted to extreme weather. The final peak demand forecasts, by station, are provided below:

Table B.5 | Winter Peak Demand Forecast (MW) by Station

Transformer Station	2019	2020	2021	2022	2023	2024	2025 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	1.65	1.66	1.66	1.67	1.67	1.68	1.69	1.69	1.71	1.72	1.73	1.74	1.76	1.78	1.79	1.81	1.83	1.85	1.86	1.88
DA Watson TS	8.53	8.57	8.55	8.56	8.57	8.58	8.60	8.63	8.67	8.71	8.75	8.80	8.87	8.93	8.99	9.06	9.13	9.20	9.26	9.32
Echo River TS	14.18	14.23	14.19	14.19	14.17	14.18	14.20	14.23	14.28	14.33	14.38	14.45	14.57	14.67	14.80	14.95	15.06	15.17	15.25	15.33
Goulais Bay TS	8.53	8.56	8.55	8.56	8.56	8.57	8.59	8.62	8.65	8.70	8.74	8.79	8.84	8.90	8.97	9.03	9.11	9.18	9.24	9.30
Limer TS (proposed TS)	13.18	13.74	13.81	13.88	13.99	54.00	54.00	54.00	54.00	54.00	54.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00
Andrews TS	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Mackay TS	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Northern Av TS	2.50	2.51	2.50	2.51	2.51	2.51	2.52	2.53	2.54	2.55	2.57	2.58	2.60	2.62	2.63	2.65	2.67	2.70	2.71	2.73
Chapleau DS	6.31	6.47	6.51	9.24	9.32	9.38	9.44	9.51	9.59	9.68	9.76	9.84	9.94	10.03	10.13	10.23	10.33	10.44	10.53	10.63
Chapleau MTS	4.47	4.36	4.44	4.19	4.69	4.58	4.59	3.89	4.21	4.15	4.14	4.27	4.27	4.27	4.27	4.28	4.29	4.29	4.29	4.30
PUC Distribution Inc.	120.7	119.5	117.5	115.9	114.2	112.7	111.4	110.0	108.9	107.9	106.8	109.7	116.5	115.7	114.9	114.2	113.6	112.9	112.3	111.5

B.6 Duration Forecast Methodology

B.6.1 General Methodology

A load duration forecast consists of a series of year long hourly profiles ("8760 profile", based on the number of hours in a year), which have been scaled to the appropriate annual peak demand. These profiles are studied to determine the feasibility of using non-wires alternatives to address needs in the region, and to determine which type of non-wires alternatives may be best suited to meet the needs.

Hourly load forecasting was conducted on a station-level, using a multiple linear regression with approximately five years' worth of historical hourly load data. Firstly, a density-based clustering algorithm was used for filtering the historical data for outliers (including fluctuations possibly caused by load transfers, outages, or infrastructure changes).

Subsequent to the removal of outliers, the historical hourly data was combined with select predictor variables to perform a multiple linear regression and model the station's hourly load profile. For the ELS region, the following predictor variables were used:

- Calendar factors (such as holidays and days of the week)
- Weather factors (including temperature, dew point, wind speed, cloud cover, and fraction of dark; both weekday and weekend heating, cooling, and dead band splines were modelled)
- Demographic factors (population data[2])
- Economic factors (employment data[3])

Model diagnostics (training mean absolute error, testing mean absolute error) were used to gauge the effectiveness of the selected predictor variables and to avoid an over-fitted model. While future values for calendar, demographic, and economic variables were incorporated in a relatively straightforward manner, the unreliability of long-term weather forecasts necessitated a different approach for predicting the impact of future weather.

Each future date was first modelled using historical weather data from the equivalent day of year throughout the past 10 years. Additionally, to fully assess the impact of different weather sequences against the other non-weather variables, the historical weather for each of the 10 previous years was shifted both ahead and behind up to seven days, resulting in 15 daily variations. This approach ultimately led to 150 possible hourly load forecasts for each future year being forecast. For example:

- 10 years of historical weather data ×15 weather sequence shifts =150 weather scenarios for each year being forecast
- E.g., June 2nd 2025 was forecasted assuming the historical weather from every May 26th to June 9th that occurred between 2011 and 2020.

Subsequently, the list of 150 forecasts were ranked in ascending order based on their median values. Load duration curves which illustrate this ranking can be seen in Figure B-5.

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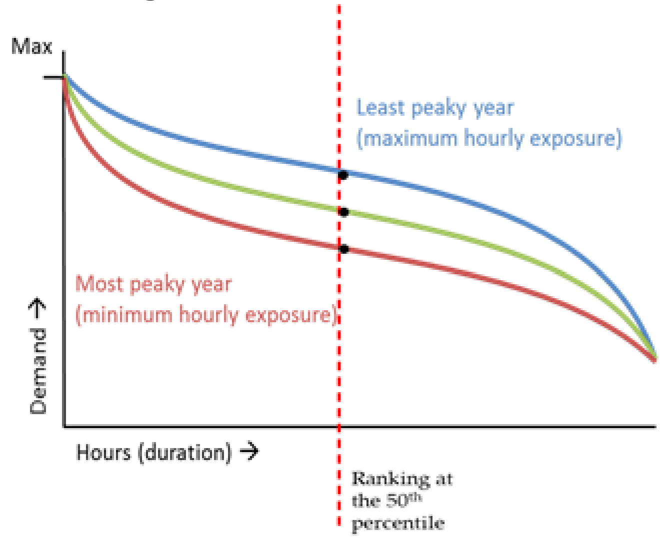
[2] Sourced from the Ministry of Finance and Statistics Canada

[3] Sourced from the Centre for Spatial Economics, IHS Markit Ltd., and the Conference Board of Canada

Figure B.6 | Example of Ranking Load Duration Curves Created from Hourly Load Profiles



The forecast in the 3rd percentile was chosen as the "Extreme Peak" (extreme profile, red curve) and the forecast in the 50th percentile was chosen was the "Median Peak" (median profile, green curve).

The yearly forecasts were scaled to their respective maximums from the peak demand forecast, and added together to form a single multi-year forecast.

B.6.2 St. Mary's MTS and Tarentorus MTS

For the purpose of this IRRP, need characterization was done for St Mary's MTS and Tarentorus MTS. These stations are prioritized first in the existing GLP Instantaneous L/R scheme and are located in an area linked to the needs identified in the study (i.e., they are served by Third Line TS).

The historical hourly data for both stations was combined and one linear regression model was used. Once the 150 normalized forecasts were created, they were scaled to PUC Distribution's extreme weather peak demand forecast. The load duration forecast provided information regarding the amount by which the load is expected to exceed the limit of 42 MW (forecasted peak demand less load rejection required for the P21G + P22G double contingency) as well as the amount of time spent over the limit, or the total event hours. Table B.6.2 shows the annual energy requirements based on this information.

Table B.6.2 | 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

Figure B.6.2 is a visual representation of the percentage of the total event hours that are associated with each range of capacity need for the 2019 and 2040 load duration forecasts. For example, in 2019 approximately 4% of the total time spent over the limit was at least 10 MW over and was in the first hour of the day.

Figure B.6.2 | Energy Not Served for St. Mary's MTS and Tarentorus MTS

2019

Capacity Need (MW)																								
90																								
80																								
70											0.02%							0.02%	0.02%	0.02%	0.02%			
60								0.02%	0.1%	0.1%	0.05%	0.05%	0.05%	0.05%	0.05%	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.02%
50								0.4%	1%	1%	0.5%	0.3%	0.4%	0.3%	0.3%	0.4%	1%	1%	1%	1%	1%	0.5%	0.1%	0.05%
40	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	1%	1%	1%	2%	1%	1%	1%	1%	1%	1%	2%	3%	3%	3%	2%	2%	1%	0.5%
30	1%	1%	1%	1%	1%	1%	2%	3%	3%	3%	2%	2%	2%	2%	2%	2%	3%	3%	4%	4%	4%	3%	3%	2%
20	3%	2%	2%	2%	2%	3%	4%	4%	4%	3%	3%	3%	3%	3%	3%	3%	4%	4%	4%	4%	4%	4%	4%	3%
10	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	3%	4%	3%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
0	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
HOUR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24

2040

Capacity Need (MW)																								
90																								
80																								
70													0.03%											
60													0.1%	0.1%	0.1%	0.03%								
50										0.1%	0.1%	0.2%	0.4%	0.4%	0.2%	0.2%	0.2%	0.03%						
40									0.2%	0.4%	1%	1%	1%	1%	1%	1%	1%	1%	0.3%	0.03%				
30	0.03%					0.03%	0.2%	0.4%	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	0.4%	0.3%	0.2%	0.1%
20	0.3%	0.3%	0.3%	0.3%	0.3%	0.5%	1%	1%	2%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	2%	2%	1%	1%	1%
10	2%	2%	1%	1%	2%	2%	2%	3%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	3%	3%	3%	2%
0	4%	3%	3%	3%	4%	4%	4%	4%	4%	4%	4%	4%	5%	4%	4%	5%	5%	4%	5%	5%	5%	4%	4%	4%
HOUR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24

Appendix C. Options and Assumptions

C.1 Economic Assumptions

An economic analysis was performed in order to compare the relative net present value ("NPV") of the feasible IRRP alternatives, including the lowest cost generation option that could meet the characteristics of the need and transmission options. The relative performance of the option (or combination of options) NPVs informs the identification of the most cost-effective options for meeting the region's needs.

Local Generation

The least-cost local generation alternative that could meet the characteristics of the region's needs is a new combined cycle gas turbine (CCGT) together with continued participation of existing demand response resources; the estimated NPV of this 65 MW generator is $250 Million. A local generator sited strategically in the 115 kV system could technically meet the reliability needs identified in the region, including the thermal overload of 115 kV circuit Sault No.3 and to prevent arming of load following the PxG contingencies. However, the cost of implementing this alternative exceeds the sum of the individual transmission solutions being recommended as part of this plan. However, such an alternative should continue to be considered as part of the IESO's Northeast Bulk Planning Study which will consider the thermal overload of the Sault No.3.

The following is a list of the assumptions made in the economic evaluation for the local CCGT option:

- The NPV of the cash flows is expressed in 2020 $CAD.
- The NPV analysis was conducted using a 4% real social discount rate (SDR). An annual inflation rate of 2% is assumed.
- An CCGT was identified as the least-cost resource alternative. The estimated levelized capacity cost assumed is about $313/kW-yr (2020 $CAD), based on escalating values from a previous study independently conducted for the IESO. The selection of this option for comparison to the transmission alternative did not account for potential operational issues that may arise during planned maintenance activities or forced outages to the unit. The life of the CCGT was assumed to be 30 years.
- Natural gas prices were assumed to be an average of $4/MMBtu throughout the study period.
- The USD/CAD exchange rate was assumed to be 0.78 for the study period.
- Carbon pricing assumptions are similar to the assumptions in the Annual Planning Outlook (i.e. carbon pricing is calculated based on the Output Based Performance Standards. This comes out to $0.00421/kg CO_2e in 2023, growing to $0.02524/kg CO_2e in 2040).
- System capacity value was $141k/MW-yr (2020 CAD) based on the CA reference price.
- The DR values was 49k/MW-yr (2020 CAD) based on the average Northeast summer and winter DRA clearing prices from 2018-2020.

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

The estimated NPV of total costs to enable remote arming of load in the existing GLP load rejection scheme for the loss of P21G and P22G circuits is $50,000. While the scheme can be manually armed, the enabling of remote arming of load 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.

Automate Patrick St TS Manual Load Shedding Scheme

The estimated NPV of automating the manual load-shedding scheme at Patrick St TS is $2 Million. 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. The automated scheme must also be expanded to arm load for the Patrick St TS 214 BKF.

Appendix D. Planning Study Results

East Lake Superior Region

Study Report

Table of Contents

1. Overview

The East Lake Superior (ELS) 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.

The load in this area is comprised of primarily industrial, commercial and residential which peaks in the winter. Figure 1 shows the seasonal peak loading in the region over the period of five years from 2014-2018. The majority of the load is concentrated in and around the city of Sault Ste. Marie.

Figure 1 | Seasonal Peak Demand for ELS Region

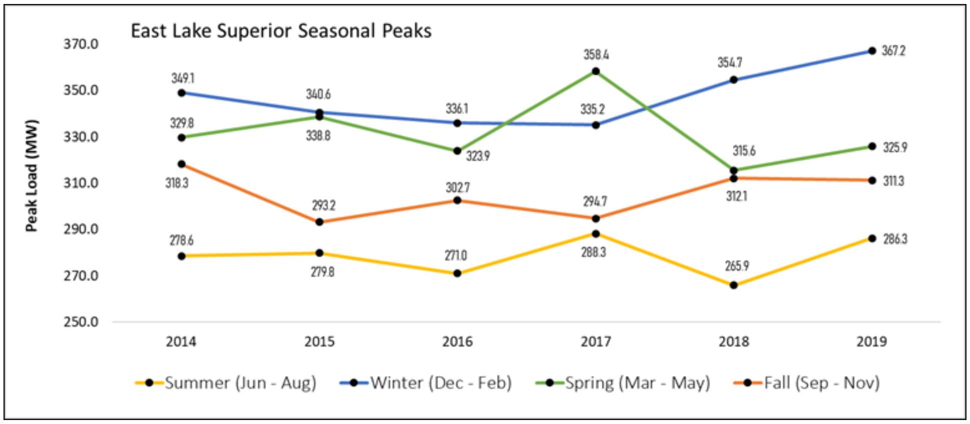
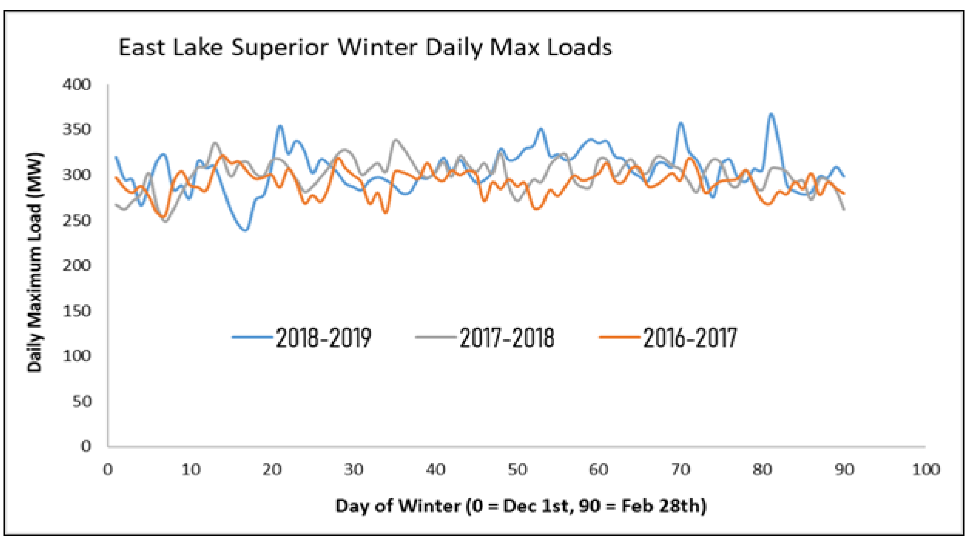


Figure 2 shows the daily winter peak load for the region from the period 2016-2019. This shows the load profile in the area is fairly flat over the winter months hovering within 10% of the peak load.

Figure 2 | Historical Daily Winter Peak Demand



Electrical supply to the region is provided through 230/115 kV autotransformers at Third Line 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 3. The region is defined electrically by the 230 kV transmission circuits bounded by Wawa TS to the northwest and Mississagi TS to the southeast.

The 230 kV transmission facilities in this area provide both regional system and bulk system functions. That is, in addition to supplying local customers, they form part of an integrated network that enables the bulk transfer of electricity across the province.

The region has over 1,200 MW of generation, including numerous hydroelectric facilities, solar and wind farms and thermal generating facilities. 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.

The single line diagram of this region is shown Figure 3 and the geographical transmission map is shown is Figure 4.

Figure 3 | East Lake Superior Single Line Diagram

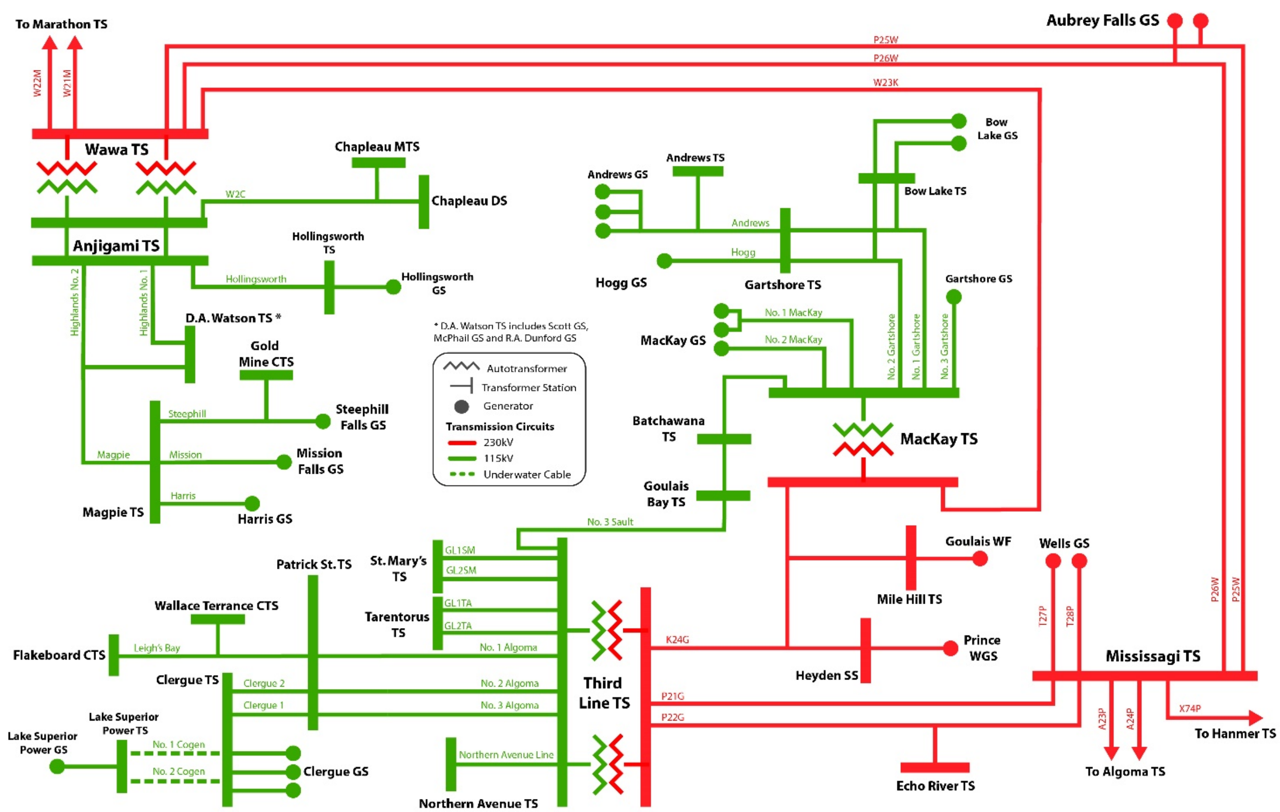
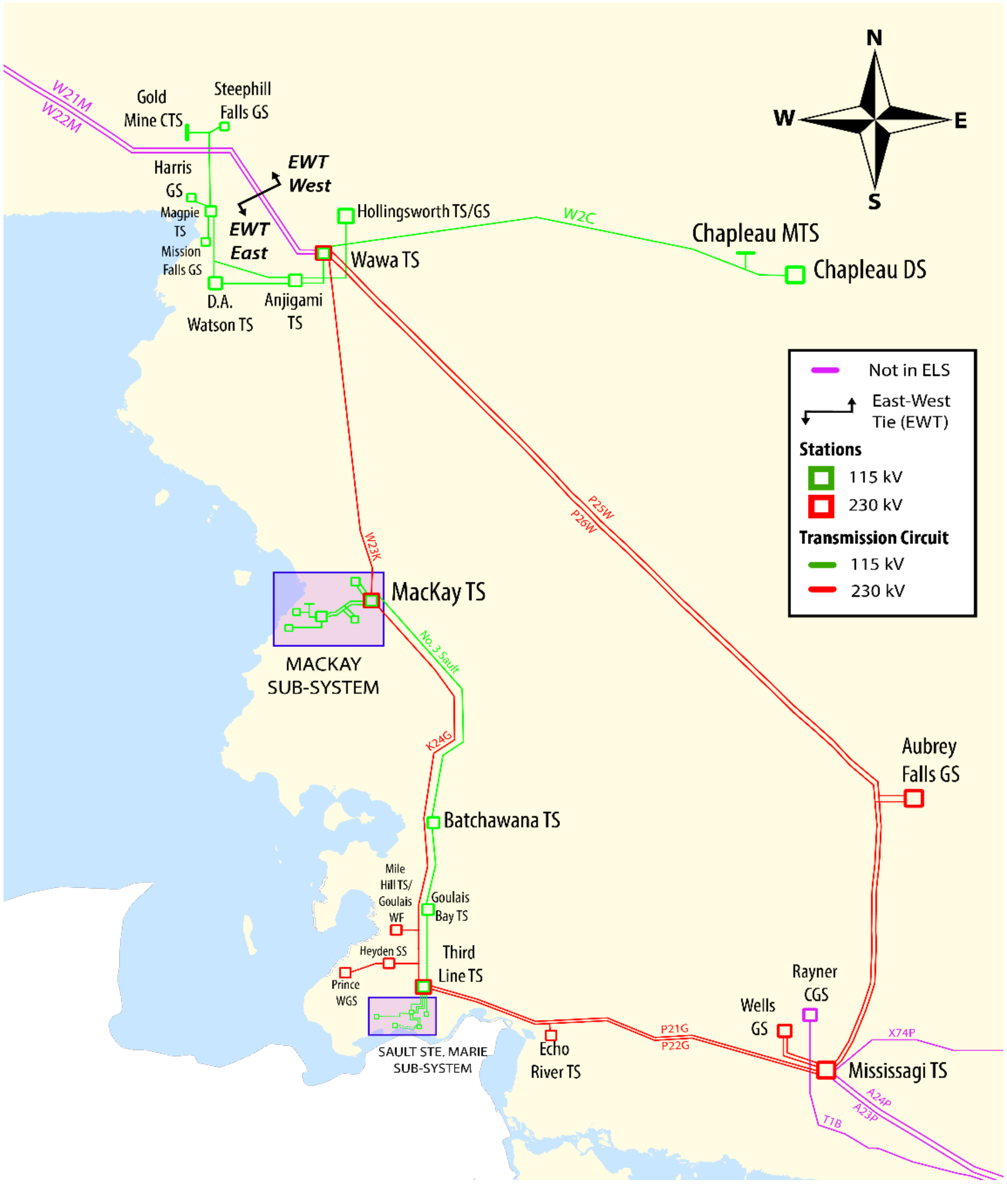


Figure 4 | East Lake Superior Transmission System



1.1 Load Forecast

Load forecast is as provided by the participating LDCs. In this region, the historical peak demand growth has been flat (neither increasing nor decreasing). For assessments concerning the regional transmission system, the non-coincident peak demand was used as a conservative approach, except for PUC Distribution Inc.'s stations where co-incident peak demand is used due to their ability to transfer loads between St. Mary's TS and Tarentorus TS during peak demand. Assessments of station-level adequacy used the same non-coincident forecast. This station level forecast snapshot for years 2020, 2025, 2030, and 2040 (end of planning horizon) is provided in Table 1 below.

Where needs are identified in the near term to medium term, further studies will be performed to refine the need using interim year forecast values to determine more precisely the load level and/or year the need arises.

Where appropriate, hourly load profiles may also be developed to aid in the evaluation of alternative such as non-wires options. The load forecast for industrial loads will be based on the information provided by individual load customers, historical hourly demand, information provided by LDCs, or other sources.

A load's power factor of 0.9 lagging is assumed at the Designated Metered Point. If voltage issues are discovered in the assessment, power factor sensitivities will be tested.

Table 1 | Station Load Forecast for ELS Region by LDC

Station	LDC	2020	2025	2030	2040
Chapleau DS	H1-SSM	6.4	9.6	9.6	9.6
St Mary's TS and Tarentorus TS	SSM PUC	116.1	112.3	111.1	112.2
Andrew TS	Algoma Power	0.2	0.2	0.2	0.2
Northern Ave TS	Algoma Power	3.2	3.3	3.4	3.6
Anjigami TS /Hollingsworth TS	Algoma Power	13.7	51.6	51.9	52.4
Mackay TS	Algoma Power	0.04	0.04	0.04	0.04
Echo River TS	Algoma Power	14.3	14.8	15.0	15.8
DA Watson TS	Algoma Power	8.6	8.9	9.2	9.6
Batchawana TS	Algoma Power	1.8	1.9	1.9	2.0
Goulais TS	Algoma Power	8.6	9.5	9.7	10.1

1.2 Local Generation Assumptions

Transmission connected local generation facilities are tabulated in Table 2. Distribution connected generation facilities, are considered load modifiers and therefore, their output is reflected as a net reduction in load as described in Appendix B of the IRRP Appendices.

Capacity assumptions in the basecase consider the amount of generation that is dependable for the majority of the time. For the hydroelectric facilities, their capacity is taken as the output that is coincident with the region's overall 98% dependable hydroelectric output.

The dependable generation output at each facility is represented by the minimum number of generator units required to produce that power. Furthermore, any units available to provide condensing services were modeled in accordance with their latest Reactive Support and Voltage

Control (RSVC) contracts. This ensures that reactive power support is reasonably, but conservatively estimated.

The wind generation facilities were modelled based on their summer and winter capacity contribution factors as per IESO's Reliability Outlook, multiplied by their peak capacity.

Table 2 | Local 98% Dependable Generation Capacity

Station	Fuel	Winter	Summer
Andrews	Hydro	0.03	0.09
Clergue	Hydro	41.86	34.02
DA Watson	Hydro	12.76	3.60
Gartshore	Hydro	0.01	0.06
Harris	Hydro	1.98	0
Hogg	Hydro	0.01	0.06
Hollingswoth	Hydro	3.21	1.50
Mackay	Hydro	0.03	0.12
Mission Falls	Hydro	2.55	0
Steephills	Hydro	1.79	0
Prince Wind Farm	Wind	5.44	1.85
Bow Lake	Wind	3.01	1.36
Goulais Wind	Wind	0	0.78

1.3 Major Interface Flows

Table 3 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 3 | System Interface Flows

Interface	Definition	Transfer Capability (MW)	Interface Assumption (MW)
GLP-Inflow	MW Flow west at Mississagi TS on P21G and P22G plus MW flow into Third Line TS on K24G	295	280
East West Tie West (EWTW)	MW flow west at Wawa TS on W21M and W22M	350 (450 after 2022	332 (450 after 2022)
East West Tie East (EWTE)	MW flow east at Wawa TS on W21M and W22M	325 (450 after 2022)	309 (450 after 2022)

1.4 Monitored Circuits and Sections

Table 4 shows the winter and summer ratings for circuits and their corresponding circuit sections that will be monitored in this region. These ratings are derived from Hydro One's Power System Database (PSDb).

Table 4 | Monitored Circuits and Ratings

Circuit	From	To	Winter Cont (A)	Winter LTR (A)	Winter STE (A)	Summer Cont (A)	Summer LTR (A)	Summer STE (A)
W23K-1	Wawa TS	MacKay JCT	1420	1720	2000	1220	1570	1860
W23K-2	MacKay JCT	MacKay TS	1459	1459	2000	1255	1255	1945
K24G-1	Third Line TS	Heyden JCT	1459	1459	2000	1255	1255	1945
K24G-2	Heyden JCT	Mile Hill JCT	1459	1459	2000	1255	1255	1945
K24G-3	Mile Hill JCT	MacKay TS	1459	1459	2000	1255	1255	1945
K24G-4	Heyden JCT	Heyden CTS	1459	1459	2000	1255	1255	1945
K24G-5	Mile Hill JCT	Mile Hill CTS	1459	1459	2000	1255	1255	1945
P21G-1	Mississagi TS	P21G POLE 6 JCT	1115	1115	1200	954	954	1064
P21G-2	P21G POLE 6 JCT	Third Line TS	1115	1115	1200	954	954	1064
P22G-1	Mississagi TS	Echo River TS	1115	1115	1200	954	954	1064

Circuit	From	To	Winter Cont (A)	Winter LTR (A)	Winter STE (A)	Summer Cont (A)	Summer LTR (A)	Summer STE (A)
P22G-2	Echo River TS	Third Line TS	1115	1115	1200	954	954	1064
P25W-1	Mississagi TS	Aubrey Falls JCT	1020	1130	1190	880	1010	1070
P25W-2	Aubrey Falls JCT	Wawa TS	1020	1020	1020	880	880	880
P25W-3	Aubrey Falls JCT	Aubrey Falls CGS	1020	1130	1190	880	1010	1070
P26W-1	Mississagi TS	Aubrey Falls JCT	1020	1130	1190	880	1010	1070
P26W-2	Aubrey Falls JCT	Wawa TS	1020	1020	1020	880	880	880
P26W-3	Aubrey Falls JCT	Aubrey Falls CGS	1020	1130	1190	880	1010	1070
Sault No.3-1	Third Line TS	Goulais Bay TS	200	200	200	200	200	200
Sault No.3-2	Goulais Bay TS	Batchawana TS	200	200	200	200	200	200
Sault No.3-3	Batchawana TS	MacKay TS	200	200	200	200	200	200
Sault No.3-4	Goulais Bay TS	Goulais Bay TS	600	600	600	600	600	600
Sault No.3-5	Batchawana TS	Batchawana TS	600	600	600	600	600	600
GL1TA	Third Line TS	Third Line JCT #1	784	784	784	672	672	672
GL2TA	Third Line TS	Third Line JCT #1	784	784	784	672	672	672
GL1SM	Third Line TS	Third Line JCT #2	784	784	784	672	672	672
GL2SM	Third Line TS	Third Line JCT #2	784	784	784	672	672	672
W2C-1	Wawa TS	Chapleau JCT	320	360	360	280	320	320
W2C-3	Chapleau JCT	Chapleau DS	320	380	420	280	350	390
W2C-4	Chapleau JCT	Chapleau DS	320	380	420	280	350	390
W2C-5	Chapleau JCT	Chapleau MTS	370	440	490	320	400	460
No.1 Algoma	Third Line TS	Patrick St CTS	627	627	681	538	538	578
No.2 Algoma	Third Line TS	Patrick St CTS	784	784	887	672	672	751

Circuit	From	To	Winter Cont (A)	Winter LTR (A)	Winter STE (A)	Summer Cont (A)	Summer LTR (A)	Summer STE (A)
No.3 Algoma	Third Line TS	Patrick St CTS	784	784	887	672	672	751
Northern Avenue	Third Line TS	Northern Avenue TS	784	784	847	672	672	720
No. 1 Clergue	Patrick St CTS	Clergue TS	627	627	660	538	538	562
No. 2 Clergue	Patrick St CTS	Clergue TS	627	627	660	538	538	562
Leigh's Bay	Patrick St CTS	Wallace Sub CTS	837	837	898	717	717	763
Leigh's Bay	Wallace Sub CTS	Flakeboard CTS	837	837	898	717	717	763
No. 1 MacKay	MacKay TS	MacKay CGS	627	627	660	538	538	562
No. 2 MacKay	MacKay TS	MacKay CGS	627	627	660	538	538	562
No. 1 Gartshore	MacKay TS	Bow Lake JCT #2	627	627	660	538	538	562
No. 1 Gartshore	Bow Lake JCT #2	Gartshore SS	627	627	660	538	538	562
No. 2 Gartshore	MacKay TS	Bow Lake JCT #2	627	627	660	538	538	562
No. 2 Gartshore	Bow Lake JCT #2	Gartshore SS	627	627	660	538	538	562
Andrews	Andrews JCT #2	Andrews TS	365	365	365	313	313	313
Hogg	Gartshore SS	Hogg CGS	414	414	414	355	355	355
No. 3 Gartshore	Gartshore SS	Gartshore CGS	627	627	660	538	538	562
Hollingsworth	Anjigami TS	Anjigami JCT #2	541	541	561	464	464	479
No. 1 High Falls	Anjigami TS	DA Watson TS	627	627	627	464	464	479

Circuit	From	To	Winter Cont (A)	Winter LTR (A)	Winter STE (A)	Summer Cont (A)	Summer LTR (A)	Summer STE (A)
No. 2 High Falls	Anjigami JCT	DA Watson TS	490	490	490	420	420	420
Magpie	DA Watson TS	Magpie SS	784	784	847	672	672	720
Steephill	Magpie SS	River Gold JCT	627	627	660	538	538	562
Harris	Magpie SS	Harris CGS	627	627	660	538	538	562
Mission	Magpie SS	Mission Falls CGS	627	627	660	538	538	562

1.5 Special Protection Schemes

Table 5 | Relevant Remedial Action Schemes (RAS)

Facility	Description
Third Line TS	a) GLP Instantaneous Load Rejection Scheme, b) Northwest Load Rejection Scheme, and c) Under Voltage Sault Local Load Rejection Scheme
Mackay TS	MacKay TS – No.3 Sault 115 kV Line – Generation Rejection (G/R) Scheme

There are three existing Remedial Action Schemes (RASs) located at Third Line TS: a) GLP Instantaneous Load Rejection Scheme, b) Northwest Load Rejection Scheme and c) Under Voltage Sault Local Load Rejection (L/R) Scheme. The GLP Instantaneous Load Rejection Scheme have six load blocks that can be armed and shed 115kV connected load for either the loss of both Third Line transformers or the loss of both P21G and P22G. The Northwest Load Rejection Scheme can be armed for the automatic load rejection which will be initiated from Mississagi TS for the loss of both A23P and A24P in "MISS x ALG Zone", or S22A or X27A in the "ALG x SUD Zone". Five protective relays (R1 to R5) control the arming of five load blocks (Load Block 1 to Load Block 5) of the Northwest Load Rejection Scheme, which are armed in a preferred order to minimize impact on certain critical loads such as hospitals. 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.

The primary purpose of the MacKay TS – Sault No.3 115 kV circuit – Generation Rejection (G/R) Scheme is to ensure the post-contingency load on No.3 Sault 115 kV circuit is within its continuous 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.

The scheme is expected to be armed when Sault No.3 circuit is operated in parallel with the normal 230 kV system and the following conditions exist:

1) The total generation flow out of MacKay TS exceeds the continuous rating of the Sault No.3 circuit which will result in a post contingency flow above the continuous rating for the loss of T2 including the 115 kV NORTH BUS and 230 kV T2H BUS or

2) East-West system flows are high in the east direction and GLP system generation is high which will result in a post contingency flow above the continuous rating of Sault No.3 for loss of K24G 230 kV circuit.

2. Credible Scenarios and Planning Events

The following sections below outline the scenarios and contingencies that have been assessed. For practical purposes, recognizing the level of precision of demand forecasts, the study will initially focus on analyzing scenarios and contingencies for the conditions in the following years; 2025 (to represent the near-term planning horizon), 2030 (to represent the medium-term planning horizon), and 2035 and 2040 (to represent the long-term planning horizon).

2.1 Studied Scenarios

Table 6 describes the various scenarios that were studied in this regional planning cycle. In addition, high industrial growth around the proposed Limer TS was also included as a sensitivity analysis. Limer TS is a newly proposed 115/44kV transformer station which will be connected between Hollingsworth TS and Anjigami TS to support the proposed load growth in this sub-region. This was applied to the most limiting contingencies found in the scenarios below. The results in this report reflect that sensitivity.

Table 6 | Scenarios to be Assessed

Scenario Name	Scenario Type	Scenario Description
Scenario 1	Winter peak, extreme weather, long-range forecast	• Dependable winter generation • Bulk transfer at 5% less than TTC • East West Transfer flowing east
Scenario 2	Winter peak, extreme weather, long-range forecast	• Dependable winter generation • Bulk transfer at 5% less than TTC • East West Transfer flowing west
Scenario 3	Summer peak, extreme weather, long-range forecast	• Dependable summer generation • Bulk transfer at median historical levels • East West Transfer flowing east
Scenario 4	Summer peak, extreme weather, long-range forecast	• Dependable summer generation • Bulk transfer at median historical levels • East West Transfer flowing west
Scenario 5	Median low-demand	• Dependable winter generation • Bulk transfer at median historical levels • East West Transfer flowing west

Table 7 describes the various types of Planning Events that were simulated while conducting the studies in this regional plan.

Table 7 | Contingencies Assessed

Pre-Contingency State	Contingency
All Elements In-Service	[Single Element Contingencies (N-1)]
All Elements In-Service	[Common Tower Contingencies (N-2)]
All Elements In-Service	[Breaker Failure Contingencies (N-2)]
[One Element] Out-of-service	[Single Element Contingencies (N-1-1)]
One generating unit out-of-service	Single Element Contingencies (N-G-1)

2.2 Studied Contingencies

Table 8 | Studied Single Contingencies

P21G	P22G	P25W	P26W	W23K	K24G	No 3 Sault	W2C	Northern Ave.
No.1 Algoma	No.2 Algoma	No.3 Algoma	Mississagi A- bus*	Mississagi K-bus*	No.1 Clergue	No.2 Clergue	GL1SM	GL2SM
GL1TA	GL2TA	No.1 Gartshore	No.2 Gartshore	No.1 High Falls	No.2 High Falls	Third Line T1	Third Line T2	Leigh's Bay
No.1 Mackay	No.2 Mackay	No.3 Gartshore	Andrews	Hogg	Hollingsworth	Magpie	Steephill	Harris
Mission	Anjigami T1	Hollingsworth T2						

*Bus contingencies are only simulated for the All-in-service scenario

Table 9 | Studied Double Contingencies

P21G+P22G	P25W+P26W	No.1 Algoma+No.2 Algoma	Patrick St 214 BKF	Third Line 402 BKF	Third Line 408 BKF
Mississagi AL25 BKF	Mississagi L24L25 BKF	Mississagi KL24 BKF	Mississagi L26L74 BKF	Mississagi KL74 BKF	Wawa L23L25 BKF
Wawa L21L25 BKF	Wawa HL21 BKF	Wawa AL23 BKF	Third Line 412 BKF	Third Line 405 BKF	Wawa DL1 BKF
Patrick St 205 BKF	Wawa KL2 or DL2 BKF	Wawa AH BKF	Mississagi L24L25 BKF	Mississagi L23L26 BKF	Mississagi AL23 BKF

3. Planning Criteria

The study will adhere to planning criteria in accordance with planning events and performance as detailed by:

- North American Electric Reliability Corporation ("NERC") TPL-001 "Transmission System Planning Performance Requirements" ("TPL-001"), and
- IESO Ontario Resource and Transmission Assessment Criteria ("ORTAC").

Applying ORTAC, NERC and NPCC criteria to assess supply capacity and reliability needs, the following categories of needs can be identified:

- Supply capacity requirements were assessed to analyze the capability of the system to reliably supply load in the ELS region.
- Load security describes the amount of load susceptible to supply interruptions in the event of a major transmission outage.
- Load restoration describes the electricity system's ability to restore power to those customers affected by a major transmission outage within reasonable timeframes. Restoration from a normal outage should remain under eight hours, consistent with ORTAC.
- Step-down station capacity needs were identified by comparing forecast demand growth to the station's 10 day Limited Time Rating ("LTR"), or thermal capacity, to determine the net incremental requirement for transformation capacity in the area.

3.1 Supply Capacity Requirements

3.1.1 Loss of Third Line T1/T2

Loss of one of the Third Line TS autotransformers causes the companion transformer to be loaded close to its LTR rating. This is an existing situation. Once the Sault No.3 circuit comes into service in 2023 and beyond, the loading on the remaining autotransformer is reduced.

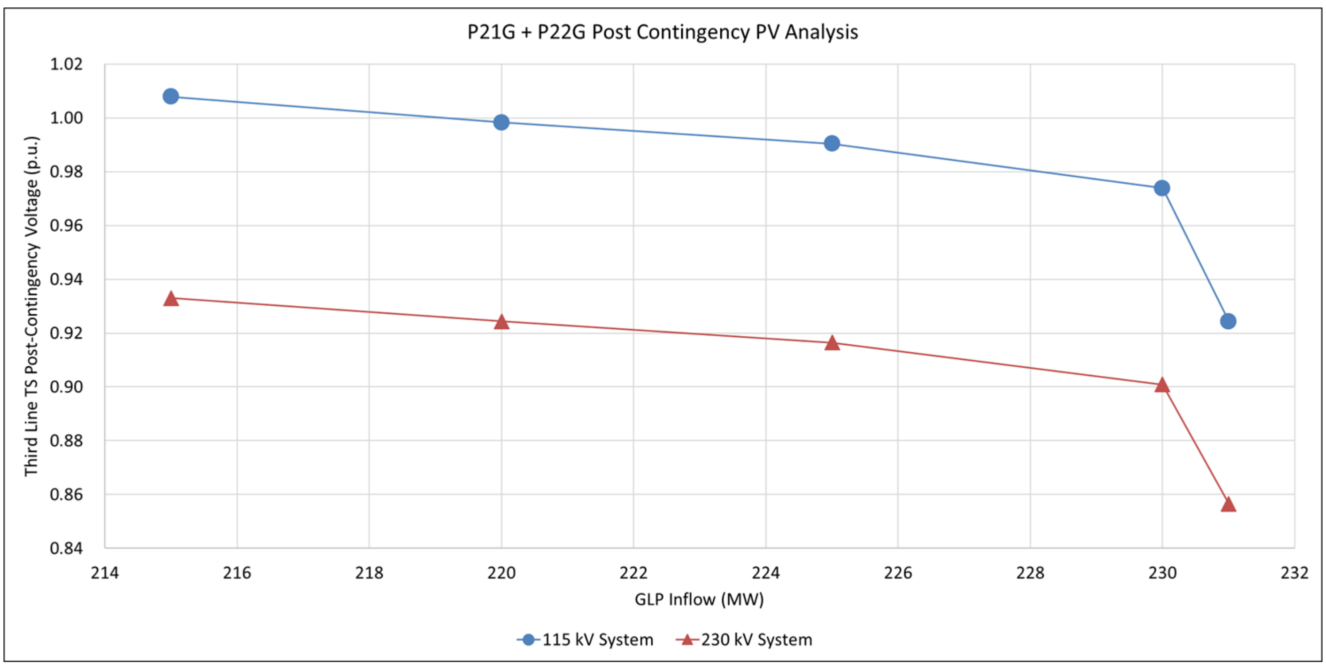
Table 10 | Third Line Autotransformer Loading Following Loss of Companion for EWTW Flow, Scenario 1

Limiting Contingency	Limiting Element	LTR Rating (MVA)	2020 Loading (MVA)	2025 Loading (MVA)	2030 Loading (MVA)	2040 Loading (MVA)
Third Line T1	Third Line T2	280	279	256	257	256

3.1.2 Loss of P21G and P22G

Loss of P21G and P22G causes voltage collapse at Third Line and other ELS stations throughout the planning period. This is illustrated in the figure below.

Figure 4 | Post Contingency PV Analysis



3.1.3 Loss of Two Algoma Circuits

Following the loss of one Algoma circuit, the loss of a second Algoma circuit would result in the remaining third Algoma circuit getting overloaded beyond its STE. The existing solution is the Patrick St Manual load shedding scheme which was designed to manage load manually to minimize the impact on the remaining Algoma circuit. However, it does not ensure the LTE rating of the remaining circuit to be respected. It was designed as an interim solution until a more permanent solution was implemented.

Table 11 | Loading on Algoma 1 Circuit Following Loss of Other Two Algoma Circuits, all Scenarios

Limiting Contingency	Limiting Element	From	To	LTE Rating (MVA)	STE Rating (MVA)	2020 Loading (MVA)	2025 Loading (MVA)	2030 Loading (MVA)	2040 Loading (MVA)
Algoma No. 2 + Algoma No. 3	Algoma No. 1	Third Line TS	Patrick St TS	627	681	727	756	774	767

3.1.4 Patrick St 214 BKF

A Breaker Failure (BKF) of the 214 breaker at Patrick St TS results in the loss of two out of the three 115 kV circuits from Third Line TS to Patrick St TS, resulting in the remaining Algoma No. 1 circuit overloaded beyond its STE rating for all years. This is also shown in Table 11 above.

3.1.5 No. 3 Sault Line Overload

During a P25W or P26W outage, a K24G contingency results in thermal overload of Sault No.3 circuit beyond its upgraded STE ratings starting in 2023.

Table 12 | Loading on No.3 Sault Circuit Following a PxW Outage and K24G Contingency, Scenario 2

Outage	Limiting Contingency	Limiting Element	From	To	LTE Rating (Amps)	STE Rating (Amps)	2020 Loading (Amps)	2025 Loading (Amps)	2030 Loading (Amps)	2040 Loading (Amps)
PxW	K24G	No. 3 Sault	Thid Line TS	Goulais Bay TS	541	561	N/A	658	718	734
PxW	K24G	No. 3 Sault	Goulais Bay TS	Batchawana TS	541	561	N/A	620	670	683
PxW	K24G	No. 3 Sault	Batchawana TS	Mackay TS	541	561	N/A	613	660	672

In addition, when one of the Third Line TS autotransformers is initially experiencing an outage, Sault No.3 circuit will need to be in-service (after its proposed upgrades) in order to prevent overloading of the companion Third Line TS autotransformer. However, if the second autotransformer is also lost, Sault No.3 circuit will be overloaded beyond its upgraded STE rating and cause a voltage collapse in the area served by Third Line TS.

3.1.6 Hollingsworth T1 and T2 Overload

For loss of Anjigami TS, in this sub-region, there is an overload on Hollingsworth T1 and T2, starting in the year 2024. This is shown in Table 13 below. The Needs Assessment report also identified that Hollingsworth TS – Transformer T2 / Anjigami TS – Transformer T1 will become overloaded due to a large customer connecting to the 44 kV system.

The incremental growth scenario, which incorporates the addition of new industrial load in this sub-region around Limer TS worsens the need identified in Table 13 to a point that loss of Anjigami T1 results in significant voltage decline in the area.

Table 13 | Loading on Hollingsworth T1 and T2 Following Anjigami T1 Contingency, all Scenarios

Limiting Contingency	Limiting Element	LTE Rating (MVA)	STE Rating (MVA)	2020 Loading (MVA)	2025 Loading (MVA)	2030 Loading (MVA)	2040 Loading (MVA)
Anjigami T1	Hollingsworth T1	33.7	52.5	11	60	62	62
Anjigami T1	Hollingsworth T2	28	28	17	60	62	62

3.2 Step-Down Station Capacity Requirements

As shown in Table 14., there is step-down station capacity needs identified in the Anjigami/Hollingsworth sub-region within the ELS region.

Table 14 | Step-down Station Capacity Needs

Station	Cont. Rating (MVA)	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	75.0	8.47	8.76	9.01	9.51
Echo River TS	25.0	25.0	14.05	14.46	14.79	15.61
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 MTS + Tarentorus MTS	210	210	116.11	112.30	111.09	112.21

3.3 Load Security

Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. The transmission system must exhibit acceptable performance while following specified design criteria contingencies. Load security criteria, as described by ORTAC Section 7.1, specify a load interruption limit of 150 MW for single element contingencies and 600 MW for double element contingencies. A summary of the load security criteria can be found in Table 6.3 of the IRRP Report.

The demand forecast in the ELS region remains below the load security criteria outlined in ORTAC. No load security need has been identified in the planning timeframe. For single contingencies, there is no loss of load greater than 150 MW by configuration and for double contingencies, there is no loss of load greater than 600 MW.

3.4 Load Restoration

The Needs Assessment provided information on restoration challenges at Andrew TS, Batchawana TS, Goulais TS and Echo River TS. The solution to the restoration will be local to the area and will be coordinated with the transmitter and impacted LDC. Following the loss of both Third Line autotransformers and Sault No.3 circuit, the entire ELS 115 kV subsytem will be islanded. Restoration procedure from this configuration already exists and documented in the SCO. Long outage times in the Chapleau sub-region have been raised through stakeholder feedback. The IESO coordinated an investigation into the matter with Working Group members and the transmitter has confirmed that there are refurbishment and component replacement plans in place for this sub-region which could alleviate this concern. The Working Group will continue to monitor the progress of these plans.

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