North & East of Sudbury Integrated Regional Resource Plan

Appendices

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The IESO recognizes the need for, and value of, transparency related to planning data underpinning the development of the North & East of Sudbury IRRP. In addition to the data provided in these appendices in tabular form, the IESO has published the data in excel format on its website[1].

[1] This file can be accessed in the link https://www.ieso.ca/en/Get-Involved/Regional-Planning/Northeast-Ontario/North-East-Sudbury

Appendix A. Overview of the Regional Planning Process

A.1 The Regional Planning Process

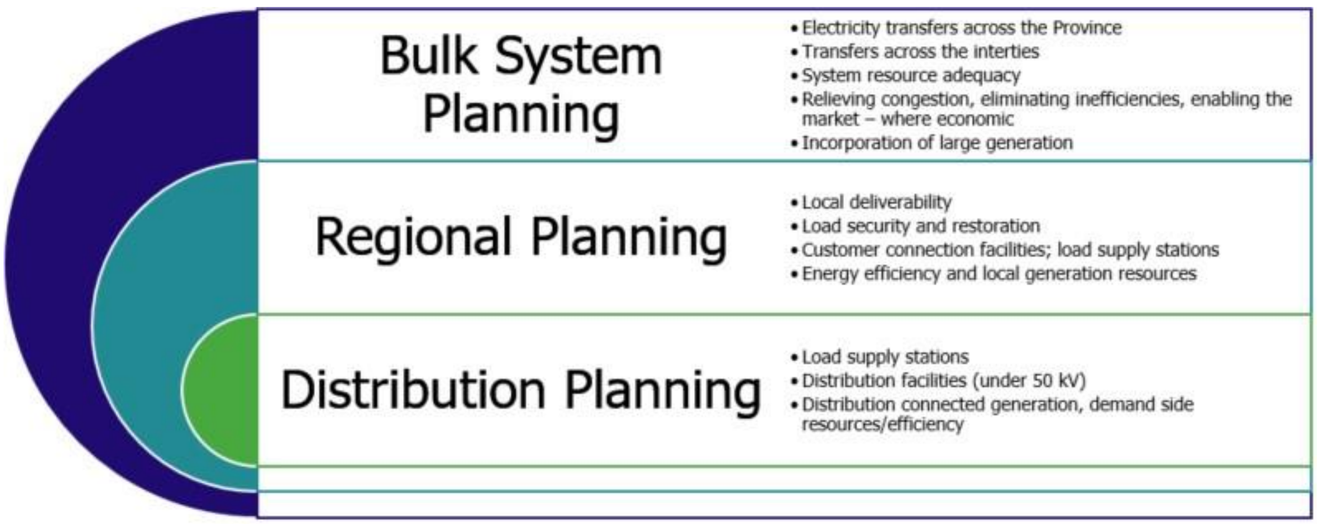
In Ontario, meeting the electricity needs of customers at a regional level is achieved through the Regional Planning process. This comprehensive process starts with an assessment of the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long 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. More recently, planning activities to address regional electricity needs have been the responsibility of the former Ontario Power Authority (OPA), now the Independent Electricity System Operator (IESO), which conducts joint regional planning studies with distributors, transmitters and other stakeholders in regions where a need for coordinated regional planning has been identified. The current Regional Planning Process was formalized through changes to the Transmission System Code and Distribution System Code in August 2013, with additional requirements of the IESO included in its license.

The regional planning process is to be initiated a minimum of once every 5 years, but can be undertaken sooner if required. The first stage of the process is a Needs Assessment performed by the transmitter, which determines whether there are needs potentially 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 preferable. In this 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 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 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. 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 websites. In addition, they may be referenced and submitted to the OEB as supporting evidence in rate cases 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, conservation, and energy management purposes. They are also a valuable source of information for individual large customers involved in the region and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning undertaken in Ontario. As shown in Figure 1, three levels of electricity system planning are carried out in Ontario.

Figure 1 | Levels of Electricity 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 supply the province adequately. 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 essential for regional planning to be coordinated with both bulk and distribution system planning, as it is the link between all levels of 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 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 North & East of Sudbury sub-region IRRP studies. Forward-looking estimates of electricity demand were provided by each of the participating LDCs and informed by the forecast base year and starting point provided by the IESO. The following sections 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.

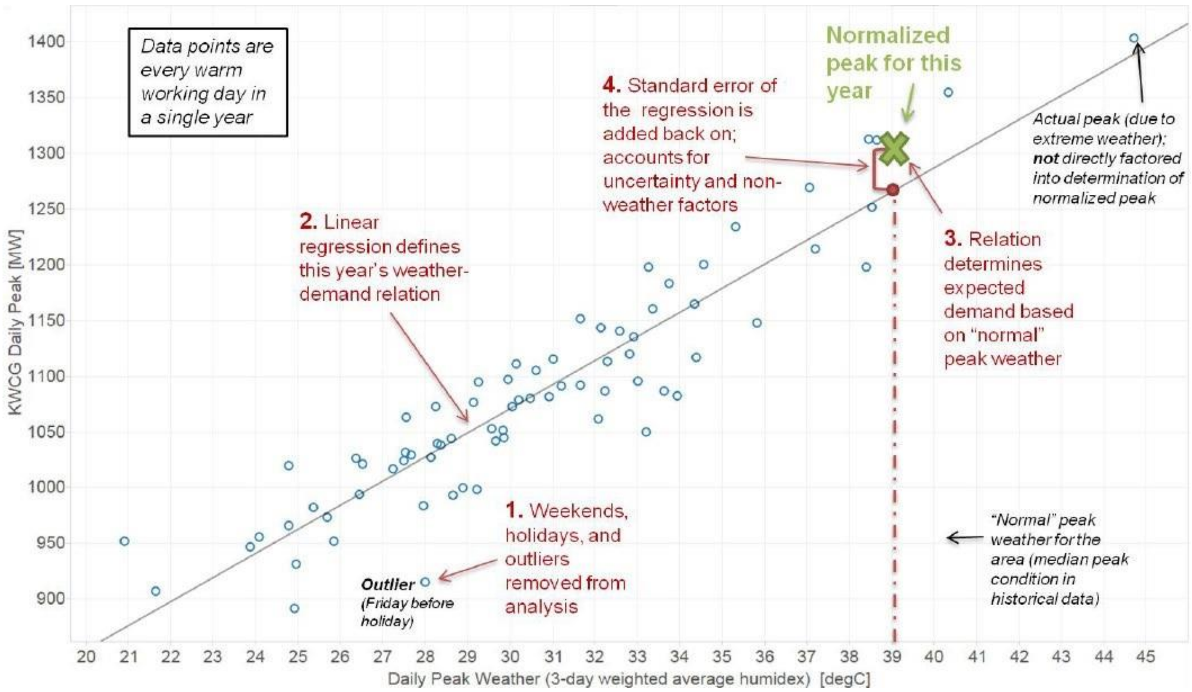
B.1 Method for Determining Forecast Starting Point

The following steps were performed to develop a standardized starting point for the North & East of Sudbury sub-region demand forecast:

- 5-year, i.e., 2016-2021, historical 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

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 2; note that this is an illustrative example developed for a different region.

Figure 2 | 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 (2021) 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 their 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 electric power system's reliability generally require using extreme weather demand forecasts. In the case of the North & East of Sudbury sub-region, the expected extreme demand happens under the coldest weather conditions, given that the North & East of Sudbury sub-region is a winter peaking area. Peaks that occur during extreme weather are generally when the electricity system infrastructure is most stressed. The extreme weather adjustment factors used in the North & East of Sudbury 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. For this IRRP, an extreme weather correction factor of 3.9% was used.

B.2 LDC Forecast Methodologies

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

- Greater Sudbury Hydro Inc.
- Hearst Power Distribution Company Limited.
- North Bay Hydro Distribution Ltd.
- Hydro One Networks Inc.
- Northern Ontario Wires Inc.

B.2.1 Greater Sudbury Hydro Inc.

Greater Sudbury Hydro Inc. (GSHI) performs load forecasting for predicting the load increase for short term (five- years term) as well as long term (ten-years term). The load forecasting is performed for two regions, Greater Sudbury region and Crystal Falls region. Hydro One supplies the primary power to Greater Sudbury Region with its TS9 Martindale and TS28 Clarabelle Transmission station. In addition, TS9's M6 feeder provides primary power to Coniston area. The load forecasting utilizes both techniques, end-use analysis and trend analysis which are based on the following factors:

Historical Trend of Seasonal Peak Load (Winter and Summer)

GSHI utilizes the historical load data recorded for previous ten years to find the seasonal peaks. The data consist of an hourly consumption of electricity per day throughout a year. The statistical analysis is performed to find the peak load during the winter and summer months by plotting the trends for every year. There are exceptions which can mislead the load as peak load, such as temporary peaks on any feeders due to the short duration paralleling of any feeders of substations owing to maintenance or emergency outage.

Population Growth Statistics

GSHI consults with the city officials and also uses the provincial government resources available on the internet to gather latest information on the population growth. It has been observed that the population is has been increasing steadily at the rate of 2.8% from 2016 to 2021 as compared to the years up to 2015. The pandemic and increasing house prices have resulted in accelerating this rate of population growth. In addition, there are increasing number of national and international students coming to the colleges and universities in Sudbury resulting in increased population in last seven years.

Housing Growth

The housing market has been steadily increasing in Greater Sudbury area with a push during the pandemic. The reasons of population growth mentioned previously are accelerating the housing. It is supposed that the upcoming growth in mining sector and industrial sector in Northern Ontario is going to accelerate the housing market in the Greater Sudbury area.

Effect of Technology on Future Trend (Electric Vehicles)

GSHI has noticed a trend in increase in the number of electric vehicles in recent years and therefore considers the growth in the load and upgrade of existing infrastructure by including a certain load increase per dwelling for independent one-unit dwellings as well as multi-residential units. The future trend of increase in load also considers the probable electrification of transportation by greater Sudbury municipality.

Distributed Generation Growth Trend

There has been a stable increase in the number of distributed generation resources every year in Greater Sudbury region as well as Sturgeon Falls region. Additionally, it is predicted that the microgeneration resources are going to increase in coming decade and therefore will impact the load forecast for GSHI.

B.2.2 Hearst Power Distribution Company Limited.

Hearts Power Distribution Company Limited. (HPDCL) load forecast is prepared in two phases. The first phase, a billed energy forecast by customer class for 2021, is developed using a total purchase (Wholesale) basis regression analysis. Then, in the second phase, usage associated with the known change in customers for 2021 is determined and added (if applicable) (Adjusted Wholesale). The methodology proposed in this application predicts wholesale consumption (Predicted) using a multiple regression analysis that relates historical monthly wholesale kWh usage to carefully selected variables. The one-way analysis of variance (ANOVA) is used to determine whether there are any statistically significant differences between the means of three or more independent (unrelated) groups. The ANOVA compares the means between the groups you are interested in and determines whether any of those means are statistically significantly different from each other.

The most significant variables used in weather related regressions are monthly historical heating degree days and cooling degree days. Heating degree-days provide a measure of how much (in degrees), and for how long (in days), the outside temperature was below that base temperature. The most readily available heating degree days come with a base temperature of 18°C. Cooling degree-day figures also come with a base temperature, and provide a measure of how much, and for how long, the outside temperature was above that base temperature.

For degree days, daily observations as reported in Ottawa are used. The regression model also uses other variables which are tested to see their relationship and contribution to the fluctuating wholesale purchases.

B.2.3 North Bay Hydro Distribution Ltd.

North Bay Hydro Distribution Limited (NBHDL) currently serves approximately 24,400 customers in its service territory within the city limits of North Bay. Approximately 87% of NBHDL's customer base is residential with the remainder being general service in the commercial, industrial, and institution sector. In determining its 20-year load forecast, NBHDL considered the following criteria:

Historical Load Data & Seasonal Weather Tracking

NBHDL reviewed historical loading data in conjunction with seasonal weather information to identify how the load demand was trending for summer and winter months. This information provided insight on load demands attributed to heating and cooling.

Residential Developments and Population Growth

NBHDL considered the amount of potential development in new subdivisions and the rate of new residential connections annually as a factor to its load growth. NBHDL also reviewed population growth rates as potential drivers for new homes and as such, new connections.

Commercial, Industrial, and Institutional (ICI) Development Growth

NBHDL reviewed the rate of new ICI connections and the average load demand of these connections and consulted with the City of North Bay on potential development plans and growth initiatives.

Electric Vehicles and Electrification Initiatives

NBHDL reviewed MTO electric vehicle registration data to collect information on the rate of adoption. NBHDL considered that North Bay, as a city closer to northern Ontario with cold winters, that the adoption rates of electric vehicles will be slower and more gradual then the provincial average. NBHDL also consider electrification incentives and initiatives for businesses to transition away from fossil fuels energy.

B.2.4 Hydro One Networks Inc.

Hydro One Distribution services the areas in the North and East of Sudbury region that other LDCs do not serve through the stations included in the study area.

- Hydro One Distribution used both econometric and end-use forecasting to develop the 20-year forecast provided to IESO.
- A baseline forecast (MW station peak in the base year) was developed, considering such factors as normal operating conditions, coincident peak loading, and extreme weather conditions.
- For the North and East of Sudbury Forecast, Hydro One Distribution used the weather-corrected peak demand levels for the stations included in the study area.
- From the established baseline year, a growth rate (%) was applied to each station demand level to provide forecast values for that within the study timeframe.
- Assumptions included in the growth rate can be related to such factors as Ontario's 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 the relation between local and provincial load, was used to augment the forecast values within the study period.

B.2.5 Northern Ontario Wires Inc.

Northern Ontario Wires Inc. currently serves approximately 6,000 customers in its service territory of Cochrane, Iroquois Falls, and Kapuskasing. Approximately 87% of NOW Inc.'s customer base is residential with the remainder being general service in the commercial, and industrial sector. In determining its 20-year load forecast, NOW Inc. considered the following criteria:

Historical Load Data & Seasonal Weather Tracking

NOW Inc. reviewed historical loading data in conjunction with seasonal weather information to identify how the load demand was trending for summer and winter months. This information provided insight on load demands attributed to heating and cooling.

Residential Developments and Population Growth

NOW Inc. considered the amount of potential development in new subdivisions and the rate of new residential connections annually as a factor to its load growth. NOW Inc. also reviewed population growth rates as potential drivers for new homes and as such, new connections.

Commercial, Industrial, and Institutional (ICI) Development Growth

NOW Inc. reviewed the rate of new ICI connections and the average load demand of these connections and consulted with the municipalities and customers regarding load changes.

Electric Vehicles

NOW Inc. is within Northern Ontario with cold winters and anticipates that the adoption rates of electric vehicles will be slower and more gradual than rest of the province.

B.3 Conservation Assumptions for North & East of Sudbury

Conservation & Demand Management (CDM) measures are designed to cost-effectively reduce electricity demand. Their impact can be separated into two main categories: Building Codes & Equipment Standards and Energy Efficiency Programs. The assumptions used for the North & East of Sudbury IRRP forecast are consistent with the CDM assumptions in the IESO's 2021 Annual Planning Outlook (APO), which was the latest provincial planning product when the demand forecast for this IRRP was developed. A top-down approach was used to estimate peak demand savings from the provincial level to the Northeast transmission zone and then allocated to the North & East of Sudbury sub-region. This section describes the process and methodology used to estimate CDM savings for the North & East of Sudbury sub-region and provides more detail on how the estimated savings 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 by sector were estimated for the Northeast zone and compared with the gross peak demand forecast for the zone separately. From this comparison, annual peak reduction percentages were developed for the purpose of allocating the associated savings to each station in the region.

Consistent with the gross demand forecast, 2020 was used as the base year. New peak demand savings from codes and standards were estimated from 2021 to 2040. The residential annual peak reduction percentages for each year were applied to the forecast residential peak demand at each station to develop an estimate of peak demand impacts from codes and standards. By 2040, the residential sector in the region is expected to see about 8.7% summer peak demand savings through codes and standards. The same is done for the commercial sector, which will see about 2.1% peak-demand savings through codes and standards by 2040. The sum of the savings associated with the two sectors are the total peak demand impact from codes and standards. It is assumed that there are no savings from codes and standards associated with the industrial sector.

B.3.2 Estimate Savings from Conservation Programs

In addition to codes and standards, delivering energy efficiency programs reduces electricity demand. The impact of existing, committed, and expected future energy efficiency programs were analyzed, which include the provincial 2021 – 2024 CDM Framework, the existing federal programs, and assumed continuing provincial CDM programs post-2024. A top-down approach was used to estimate the peak demand reduction due to the delivery of these programs, from the province to North East zone and finally to the stations in the region. The persistence of the peak demand savings from energy efficiency programs was also considered over the forecast period.

Similar to the estimation of peak demand savings from codes and standards, annual peak demand reduction percentages from 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 zone. They were then applied to the sectoral gross peak forecast of each station in the region. By 2040, the residential sector in the region is expected to see about 1.5% summer peak demand savings through programs, while commercial sector and industrial sector will see about 11.5% and 2.4% summer peak reduction respectively.

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 are summarized in Table 1. The analyses were conducted under normal weather conditions and can be adjusted to reflect extreme weather conditions. The resulting forecast savings and the impact of distributed generation resources were applied to gross demand to determine net peak demand for further planning analyses.

Table 1 | Forecast of Expected Winter Peak Demand Savings (MW) Due to Codes and Standards, and Conservation Programs - by station

Transformer Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Crystal Falls TS	0.14	0.24	0.42	0.56	0.67	0.78	0.92	1.03	1.18	1.30	1.53	1.68	1.80	1.90	1.99	2.05	2.07	2.08	2.09	2.10
Hearts TS	0.18	0.24	0.40	0.51	0.60	0.69	0.80	0.89	1.01	1.10	1.20	1.32	1.40	1.47	1.53	1.57	1.58	1.58	1.58	1.58
Kapuskasing TS	0.08	0.14	0.23	0.29	0.34	0.39	0.45	0.49	0.55	0.59	0.65	0.71	0.75	0.78	0.81	0.84	0.84	0.84	0.84	0.84
Kirkland Lake TS	0.37	0.61	0.95	1.17	1.34	1.49	1.72	1.88	2.04	2.16	2.35	2.56	2.70	2.82	2.94	3.05	3.08	3.10	3.11	3.12
North Bay TS	0.11	0.18	0.28	0.39	0.49	0.61	0.70	0.78	0.88	0.95	1.05	1.18	1.27	1.35	1.40	1.43	1.46	1.49	1.51	1.53
Otto Holden TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ramone TS	0.04	0.06	0.10	0.16	0.22	0.29	0.32	0.35	0.39	0.42	0.46	0.51	0.55	0.58	0.59	0.59	0.60	0.61	0.61	0.62
Timmins TS	0.57	0.94	1.49	1.86	2.14	2.41	2.79	3.07	3.37	3.60	3.93	4.29	4.55	4.78	4.99	5.18	5.25	5.28	5.31	5.34
Dymond TS	0.32	0.53	0.85	1.07	1.24	1.41	1.62	1.79	1.98	2.13	2.33	2.54	2.69	2.83	2.94	3.04	3.07	3.08	3.08	3.10
Trout Lake TS	0.58	1.03	1.81	2.39	2.86	3.43	4.06	4.59	5.31	5.92	6.60	7.28	7.80	8.24	8.63	8.84	8.91	8.94	8.98	9.04
Calstock DS	0.09	0.14	0.22	0.26	0.29	0.32	0.36	0.40	0.42	0.43	0.47	0.51	0.53	0.56	0.58	0.62	0.63	0.63	0.64	0.64
Cochrane MTS	0.10	0.16	0.26	0.33	0.39	0.44	0.51	0.56	0.62	0.67	0.74	0.80	0.84	0.88	0.91	0.94	0.94	0.93	0.93	0.93
Cochrane West DS	0.02	0.04	0.07	0.09	0.11	0.12	0.14	0.16	0.18	0.20	0.23	0.25	0.26	0.28	0.29	0.30	0.30	0.30	0.30	0.30

Transformer Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Fauquier DS	0.01	0.02	0.03	0.04	0.05	0.06	0.08	0.09	0.10	0.11	0.13	0.14	0.15	0.16	0.17	0.17	0.17	0.17	0.17	0.17
Herridge Lake DS	0.03	0.05	0.08	0.10	0.12	0.13	0.16	0.17	0.20	0.21	0.24	0.26	0.27	0.29	0.30	0.31	0.31	0.32	0.32	0.32
Holye DS	0.06	0.10	0.16	0.20	0.24	0.27	0.32	0.35	0.39	0.42	0.46	0.50	0.53	0.56	0.58	0.60	0.60	0.61	0.61	0.61
Iroquois Falls DS	0.04	0.07	0.12	0.15	0.17	0.20	0.23	0.25	0.28	0.31	0.33	0.36	0.39	0.40	0.42	0.43	0.43	0.43	0.43	0.43
Laforest Road DS	0.12	0.21	0.33	0.42	0.48	0.55	0.64	0.70	0.78	0.84	0.92	1.00	1.07	1.12	1.17	1.21	1.23	1.23	1.24	1.24
Mattawa DS	0.04	0.07	0.12	0.15	0.18	0.21	0.24	0.27	0.30	0.32	0.36	0.39	0.41	0.44	0.46	0.47	0.48	0.48	0.48	0.48
Monteith DS	0.02	0.03	0.06	0.07	0.09	0.10	0.12	0.14	0.16	0.17	0.19	0.21	0.22	0.24	0.25	0.25	0.26	0.26	0.26	0.26
Moosonee DS	0.14	0.23	0.37	0.47	0.54	0.61	0.71	0.78	0.86	0.92	1.00	1.10	1.16	1.22	1.27	1.32	1.33	1.34	1.34	1.35
Shiningtree DS	0.04	0.07	0.11	0.14	0.16	0.18	0.21	0.22	0.24	0.26	0.28	0.30	0.32	0.34	0.35	0.36	0.37	0.37	0.37	0.37
Smooth Rock Falls DS	0.02	0.03	0.05	0.06	0.07	0.08	0.09	0.10	0.11	0.12	0.13	0.14	0.15	0.16	0.17	0.17	0.17	0.17	0.18	0.18
Temagami DS	0.01	0.02	0.04	0.05	0.05	0.06	0.07	0.08	0.09	0.09	0.10	0.11	0.12	0.13	0.13	0.14	0.14	0.14	0.14	0.15
Verner DS	0.03	0.06	0.10	0.13	0.16	0.19	0.22	0.25	0.29	0.33	0.36	0.40	0.42	0.44	0.46	0.47	0.47	0.47	0.47	0.47
Warren DS	0.04	0.08	0.13	0.18	0.21	0.24	0.28	0.32	0.36	0.40	0.44	0.49	0.52	0.54	0.57	0.58	0.58	0.58	0.58	0.58

B.4 Distributed Energy Resources Assumptions

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

Table 2 | DG Forecast by Station

Transformer Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Crystal Falls TS	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kapuskasing TS	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07
Otto Holden TS	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ramone TS	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dymond TS	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trout Lake	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.27	5.27	5.01	5.01	5.01	5.01	5.01	5.01	5.01	3.95

DG capacity factors were applied using factors from the Reliability Outlooks (RO) and the APO.

- Solar capacity contribution: Summer Average 13.8% - Winter Average 0%
- Wind capacity contribution: Summer Average 13.7% - Winter 37.8%
- Hydro Capacity contribution: Summer Average 86.2% - Winter 81.6%

B.5 Planning Forecast by Station

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

Table 3 | Winter Peak Demand Forecast (MW) by station

Transformer Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Crystal Falls TS	19.9	20.2	19.9	20.2	20.2	20.3	20.3	20.4	20.4	23.7	25.2	25.3	25.5	25.7	25.8	26.2	26.4	26.7	27.0	27.2
Hearst TS	24.3	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.3	18.3	18.4	18.4	18.4	18.5	18.6	18.7	18.8
Kapuskasing TS	6.0	5.9	5.9	5.8	5.8	5.8	5.8	5.7	5.7	5.7	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Kirkland Lake TS	31.4	31.4	31.3	31.2	31.2	31.2	31.2	31.2	31.2	31.2	31.2	31.1	31.1	31.1	31.1	31.2	31.3	31.4	31.5	31.6
North Bay TS	27.4	26.3	25.2	24.0	22.9	23.3	23.7	24.1	24.6	25.0	25.4	25.8	26.3	26.7	27.2	27.6	28.1	28.6	29.1	29.6
Ramone TS	12.1	12.2	12.4	12.4	12.5	12.6	12.7	12.8	12.9	13.3	13.4	13.5	13.6	13.7	13.8	14.0	14.1	14.3	14.4	14.6
Timmins TS	52.6	52.7	52.8	52.8	52.9	53.1	53.2	53.4	53.6	53.8	53.9	53.9	54.1	54.3	54.5	54.7	55.0	55.4	55.8	56.2
Dymond TS	30.8	30.8	30.8	30.8	30.8	30.8	30.9	30.9	31.0	31.0	31.0	31.0	33.9	33.9	34.0	34.1	34.2	34.4	34.6	34.7
Trout Lake	100.4	100.3	98.9	97.9	97.0	100.2	100.8	101.5	102.0	102.6	103.3	103.8	104.8	105.6	106.4	107.4	108.5	109.7	110.9	113.1
Calstock DS	5.30	5.30	5.29	5.28	5.29	5.30	5.31	5.33	5.35	5.37	5.38	5.38	5.40	5.41	5.43	5.44	5.47	5.50	5.53	5.57
Cochrane DS	11.63	11.56	11.46	11.39	11.34	11.28	11.22	11.16	11.10	11.05	10.99	10.92	10.88	10.84	10.81	10.79	10.79	10.79	10.79	10.79
Cochran West DS	3.52	3.53	3.55	3.55	3.56	3.57	3.58	3.59	3.59	3.60	3.61	3.61	3.62	3.63	3.65	3.66	3.69	3.71	3.74	3.76
Fauquier DS	2.05	2.07	2.08	2.09	2.10	2.11	2.12	2.13	2.14	2.15	2.16	2.17	2.18	2.19	2.20	2.22	2.24	2.26	2.28	2.30
Herridge Lake DS	3.38	3.40	3.41	3.42	3.43	3.45	3.46	3.47	3.49	3.50	3.51	3.52	3.53	3.54	3.56	3.58	3.61	3.64	3.66	3.69
Hoyle DS	7.02	7.04	7.05	7.06	7.07	7.08	7.09	7.12	7.13	7.15	7.15	7.16	7.17	7.19	7.22	7.25	7.28	7.33	7.37	7.41
Iroquois Falls DS	5.24	5.22	5.19	5.16	5.15	5.13	5.11	5.09	5.07	5.06	5.03	5.01	5.00	4.99	4.98	4.98	4.98	4.99	5.00	5.01
Laforest Road DS	12.72	12.77	12.79	12.80	12.83	12.87	12.90	12.95	12.99	13.03	13.06	13.07	13.11	13.16	13.21	13.27	13.35	13.45	13.54	13.64
Mattawa DS	5.02	5.05	5.06	5.07	5.09	5.11	5.13	5.15	5.17	5.19	5.20	5.21	5.23	5.26	5.28	5.31	5.35	5.39	5.43	5.47
Monteith DS	2.90	2.92	2.93	2.94	2.96	2.97	2.99	3.00	3.02	3.03	3.04	3.05	3.06	3.08	3.10	3.12	3.15	3.18	3.21	3.23

Transformer Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Moosonee DS	14.25	14.29	14.31	14.31	14.33	14.37	14.40	14.45	14.48	14.53	14.55	14.56	14.59	14.63	14.68	14.74	14.82	14.91	15.00	15.09
Shiningtree DS	3.96	3.96	3.95	3.94	3.94	3.93	3.93	3.93	3.94	3.94	3.94	3.93	3.93	3.93	3.93	3.94	3.95	3.96	3.98	3.99
Smooth Rock Falls DS	1.80	1.80	1.80	1.80	1.80	1.81	1.81	1.81	1.81	1.82	1.82	1.82	1.82	1.82	1.82	1.83	1.84	1.85	1.86	1.87
Temagami DS 2	1.37	1.38	1.39	1.40	1.40	1.41	1.42	1.43	1.44	1.45	1.46	1.47	1.48	1.49	1.50	1.51	1.53	1.54	1.56	1.58
Verner DS	5.90	5.92	5.93	5.93	5.94	5.95	5.96	5.97	5.97	5.97	5.97	5.97	5.98	5.99	6.00	6.03	6.06	6.09	6.13	6.16
Warren DS	7.07	7.09	7.10	7.09	7.09	7.10	7.10	7.11	7.11	7.11	7.10	7.10	7.10	7.11	7.12	7.14	7.17	7.21	7.24	7.28

B.6 Load 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 the region's needs and 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 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 North & East of Sudbury 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 a 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 relatively straightforwardly, the unreliability of long-term weather forecasts necessitated a different approach to predicting the impact of future weather.

Each future date was first modelled using historical weather data from the equivalent day of the 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:

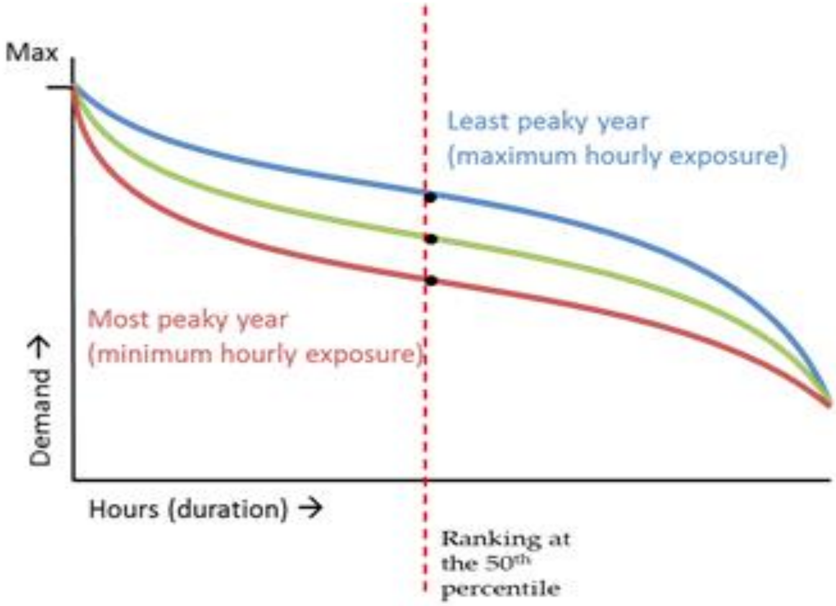
- 10 years of historical weather data ×15 weather sequence shifts =150 weather scenarios for each year being forecast
- E.g., June 2nd 2025, was forecasted assuming the historical weather from every May 26th to June 9th that occurred between 2011 and 2020.

[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

Subsequently, the list of 150 forecasts was ranked in ascending order based on their median values. Load duration curves which illustrate this ranking can be seen in **Figure 3**.

Figure 3 | 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 as 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 Ramore TS Capacity Need

See Table 10 in the North and East of Sudbury IRRP Appendix Excel file for Ramore TS' forecast hourly load profile and need in 2040.

Figure 4 | Heat Map Showing Possible Frequency of Ramore TS Capacity Need in 2040 by MW and Month

MW Range	2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	1.7777778	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	1.5555556	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	1.3333333	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	1.1111111	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	0.8888889	2%	1%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%
	0.6666667	7%	5%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%
	0.4444444	14%	11%	6%	1%	0%	0%	0%	0%	0%	0%	0%	0%
	0.2222222	25%	19%	13%	2%	0%	0%	0%	0%	0%	0%	0%	1%
	0	39%	32%	23%	4%	0%	0%	0%	0%	0%	0%	0%	2%
	MNTH	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC

Figure 5 | Heat Map Showing Possible Frequency of Ramore TS Capacity Need in 2040 by MW and Hour

MW Range	2.00	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	1.78	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	1.56	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	1.33	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	1.11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	0.89	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	0.67	0%	0%	0%	0%	0%	0%	0%	3%	4%	1%	1%	0%	2%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	0.44	1%	0%	0%	0%	0%	0%	0%	5%	6%	3%	2%	2%	4%	6%	0%	0%	0%	0%	1%	0%	0%	0%	1%	0%
	0.22	3%	3%	0%	0%	0%	0%	1%	7%	8%	6%	5%	3%	6%	8%	0%	0%	0%	0%	1%	2%	1%	1%	2%	0%
	0.00	4%	3%	2%	0%	0%	0%	2%	11%	11%	9%	8%	6%	9%	10%	1%	0%	0%	1%	4%	4%	4%	3%	4%	0%
	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

Each cell in the heat map indicates the expected frequency of a load level at Ramore TS, according to the month or hour. For instance, it is estimated that in roughly 7% of total hours in 2040, loading at Ramore TS exceeds 0.67 MW and occurs in January, as indicated in Figure 4. From an hourly perspective (Figure 5), a sustained need is estimated across day hours (roughly 7 AM – 3 PM and 5 PM to 11 PM). However, all needs are expected to be around 1 MW at its maximum.

Appendix C. Options and Assumptions

C.1 Economic Assumptions

The following assumptions were made in the economic analysis:

- The NPV of the cash flows is expressed in 2021 CAD.
- The USD/CAD exchange rate was assumed to be 0.76 for the study period.
- The NPV analysis was conducted using a 4% real social discount rate. An annual inflation rate of 2% is assumed.
- The life of the station upgrades was assumed to be 45 years, and the life of storage assets was assumed to be 15 years.
- Development timelines for storage are assumed to be 3 years.
- A deterministic capacity assessment determined the size of the resource option.
- A battery energy storage system was identified as a low-cost resource alternative. Total battery storage system costs are composed of capacity and energy costs (i.e. energy storage devices are constrained by their energy reservoir). The battery storage capacity and energy costs are based on the 2022 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB).
- The sizing of the battery storage solution was based on meeting the peak capacity and peak energy requirements for the local reliability need, such that the reservoir size can use existing resources to sufficiently charge to meet the hours of unserved energy.
- The system capacity value was $144 k/MW-yr (2021 CAD) based on an estimate for the Cost of the Marginal New Resource (Net CONE), a new simple cycle gas turbine (SCGT) in Ontario.
- Production costs were determined based on energy requirements to serve the local reliability need, assuming the battery energy storage system's fixed and variable operating and maintenance costs.
- The assessment was performed from an electricity consumer perspective and included all costs incurred by project developers, which were assumed to be passed on to consumers.

Appendix D. Planning Study Assumptions

D.1. Scenarios Assessed

D.1.1 Summary of Scenarios

This section outlines the scenarios assessed by the technical study. It covers the winter scenario of the North & East of Sudbury area, given that Northern Ontario is usually a winter peaking area. A summer peak load scenario was developed; notably, further studies were not necessary, as winter peak demand was found to be more limiting than summer thermal ratings.

The reference mining load forecast was considered under all scenarios studied. Table 1 below summarizes the proposed scenarios. Further details on the load forecast, local generation assumption, and interface flows are discussed in the subsequent subsections. Note that all scenarios assume peak load conditions consistent with the NE-Sudbury forecast.

Table 1 - Summary of Scenarios Assessed

Scenario Name	Local Generation[4]	Interface Flows	Contingencies Assessed
Winter	98% dependability for N-1, N-2	Transfer North and West	N-1, N-2, N-1-1

D.1.2 Load Forecast

The Need Assesment study used the net peak Winter forecast for Northern Ontario; Figure 1 shows a snapshot of the expected demand growth from the base year until the end of the planning horizon in 2040.

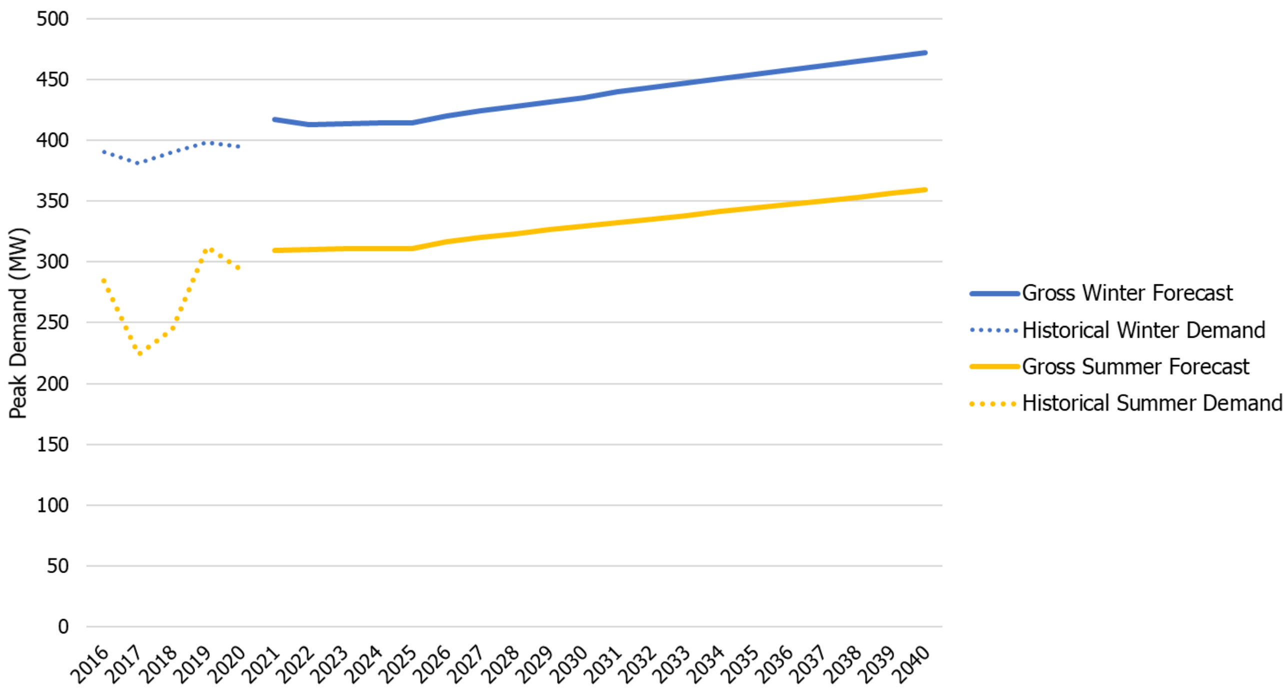
Where needs were identified, further studies were performed to refine the need and determine the exact load level/year the need occurs.

Where appropriate, hourly load profiles were developed to aid in evaluating non-wires alternatives. Historical power factors (or 0.9 in the absence of reliable data) at the load were used (without consideration for the status of low-tension capacitor banks[5]). The load forecast data tables in Excel format can be found in Tables 8 and 9.

[4] Dependable output from hydroelectric generation is assumed as its historical generation of 98% of the time during the winter months November to March.

[5] Low tension capacitor banks are often installed for the purpose of transmission system voltage control, and not power factor correction, so they are not considered for load power factor correction.

Figure 1 – Load Forecast for the North & East of Sudbury Region



D.1.3 Local Generation Assumptions

The region has over 2,600 MW of generation, including numerous hydroelectric, solar, gas and biofuel facilities.

Local hydroelectric generation and the 98% and 85% dependable levels are summarized in Table 2. This methodology used historical water flow data and converted it to daily available energy/power.

Table 2 – Dependable Hydro within Northeast

Sub-system	Installed Capacity (MW)	98% Dependable (MW)	85% Dependable (MW)
NE	2985	932	1151

D.2 System Topology

The region is currently supplied through 500/230 kV autotransformers at Porcupine T.S. and Pinard TS. It encompasses the 230 kV circuits east of Martindale TS in the west to Otto Holden TS in the east, the 500 kV circuits from Hammer TS to Pinard TS, and the 115 kV sub-systems in between.

Table 3 below are the winter and summer thermal ratings of the monitored circuit sections in the North & East of Sudbury. Hydro One has been gradually updating summer ratings in Northern Ontario from 30 C to 35 C. However, at the time of the study, only the 30 C ratings were available and therefore used.

Table 3 – Winter & Summer Ratings of Monitored Circuits and Ratings

Line	Voltage [kV]	Branch	Winter Continuous Rating [Amps]	Winter LTE Rating [Amps]	Winter STE Rating [Amps]	Summer Continuous Rating [Amps]	Summer LTE Rating [Amps]	Summer STE Rating [Amps]
D501P	500	Pinard TS to Porcupine TS	2080	2500	2720	1790	2210	2210
P502X	500	Porcupine TS to Hanmer TS	2850	2850	2850	2210	2210	2210
X503E	500	Hanmer TS to Nobel SS	2780	2780	2790	2270	2270	2270
X503E	500	Nobel SS to Essa TS	2780	2780	2790	2270	2270	2270
X504E	500	Hanmer TS to Nobel SS	2640	2640	2640	2080	2080	2090
X504E	500	Nobel SS to Essa TS	2690	2690	2690	2180	2180	2180
D5H	230	Des Joachims TS to Otto Holden TS	1020	1070	1090	840	900	920
H23S	230	Widdifield SS to Pedley JCT	620	620	620	480	480	480
H23S	230	Pedley JCT to Martindale TS	620	620	620	480	480	480
H23S	230	Pedley JCT to Crystal Falls TS	1020	1230	1510	880	1120	1430
H23S	230	Otto Holden TS to Widdifield SS	730	730	730	620	620	620
H24S	230	Grant JCT to Crystal Falls TS	1020	1230	1510	880	1120	1430
H24S	230	A.P. North Bay JCT to Grant JCT	940	940	940	780	780	780
H24S	230	A.P. North Bay JCT to A.P. North Bay JCT	1020	1230	1510	880	1120	1430
H24S	230	Grant JCT to Martindale TS	990	990	990	690	690	690
H24S	230	Otto Holden TS to Widdifield SS	1000	1000	1000	850	850	850
H24S	230	Widdifield SS to A.P. North Bay JCT	1020	1230	1250	880	1050	1050
H24S	230	Widdifield SS to Trout Lake TS	750	750	750	550	550	550
W71D	230	Widdifield SS to Lower Notch JCT	1020	1140	1200	880	1020	1080
W71D	230	Lower Notch JCT to Dymond TS	1020	1140	1200	880	1020	1080
W71D	230	Widdifield SS to Trout Lake TS	1020	1170	1240	880	1050	1130
W71D	230	Lower Notch JCT to Lower Notch GS	1020	1140	1200	880	1020	1080
A4H	115	Ansonville TS to Fournier JCT	330	330	330	260	260	260

Line	Voltage [kV]	Branch	Winter Continuous Rating [Amps]	Winter LTE Rating [Amps]	Winter STE Rating [Amps]	Summer Continuous Rating [Amps]	Summer LTE Rating [Amps]	Summer STE Rating [Amps]
A4H	115	Hunta SS to LSR MSO JCT	580	660	670	500	590	610
A4H	115	Fournier JCT to Hunta SS	330	330	330	260	260	260
A4H	115	Fournier JCT to Power JCT	350	350	350	290	290	290
A4H	115	Power JCT to Cochrane West JCT	370	440	460	320	400	420
A4H	115	Cochrane West JCT to Cochrane MTS	350	350	350	290	290	290
A4H	115	Cochrane West JCT to Cochrane West DS	370	440	490	320	400	460
A5H	115	Fournier JCT to Hunta SS	600	600	600	440	440	440
A5H	115	A.P. Tunis JCT to Fournier JCT	640	640	640	500	500	500
A5H	115	Iroquois Fls DS JCT to Iroq Falls 115 JCT	450	530	610	380	490	580
A5H	115	Ansonville TS to Iroquois Fls DS JCT	580	690	790	500	630	740
A5H	115	Iroq Falls 115 JCT to A.P. Tunis JCT	580	660	660	500	530	530
A5H	115	Fournier JCT to Fournier JCT	350	350	350	290	290	290
A5H	115	Iroquois Fls DS JCT to Iroquois Falls DS	330	330	330	260	260	260
A5H	115	A.P. Tunis JCT to A.P. Tunis JCT	580	690	710	500	630	660
A8K	115	A8K-47EO JCT to Kirkland Lake TS	580	650	670	500	590	600
A9K	115	Ansonville TS to Monteith DS JCT	580	680	690	500	600	610
A9K	115	Monteith DS JCT to Ramore TS	580	650	670	500	590	600
A9K	115	Ramore TS to Kirkland Lake TS	580	650	670	500	590	600
A8K	115	Ansonville TS to A8K-19EO JCT	640	680	690	550	600	610
A8K	115	A8K-19EO JCT to Monteith SS JCT	640	680	690	550	600	610
A8K	115	Monteith SS JCT to A8K-47EO JCT	640	680	690	550	600	610
A9K	115	Monteith DS JCT to Monteith DS	640	680	690	550	600	610
D2L	115	Herridge Lake DS to Herridge Lake JCT	720	870	1020	620	790	960
D2L	115	New Liskeard JCT to New Liskeard JCT #2	540	540	540	420	420	420
D2L	115	D2L STR 409 JCT to Crystal Falls SS	600	600	600	460	460	460
D2L	115	Herridge Lake JCT to Herridge Lake DS	720	870	1020	620	790	960
D2L	115	Cassels JCT to Cassels 2 JCT	1000	1200	1490	850	1100	1410
D2L	115	Cassels 2 JCT to Cassels JCT	1000	1200	1490	850	1100	1410
D2L	115	Marten River JCT to D2L STR 409 JCT	600	600	600	460	460	460
D2L	115	Herridge Lake JCT to Marten River JCT	720	720	730	620	620	620
D2L	115	Dymond TS to New Liskeard JCT	600	600	600	460	460	460
D2L	115	Cassels 2 JCT to Herridge Lake JCT	720	720	730	620	620	620
D2L	115	New Liskeard JCT to Upper Notch JCT	600	600	600	460	460	460
D2L	115	Upper Notch JCT to Cassels 2 JCT	720	720	730	620	620	620
D2L	115	Cassels JCT to Temagami DS	810	970	1030	700	890	940

Line	Voltage [kV]	Branch	Winter Continuous Rating [Amps]	Winter LTE Rating [Amps]	Winter STE Rating [Amps]	Summer Continuous Rating [Amps]	Summer LTE Rating [Amps]	Summer STE Rating [Amps]
H6T	115	Hunta SS to Tisdale JCT	580	610	610	500	530	530
H6T	115	Tisdale JCT to Laforest Road JCT	580	610	610	500	530	530
H6T	115	Laforest Road JCT to Timmins TS	580	610	620	500	530	540
H6T	115	Laforest Road JCT to Laforest Road DS	330	330	330	260	260	260
H7T	115	Hunta SS to Warkus JCT	580	610	610	500	530	530
H7T	115	Warkus JCT to Timmins TS	580	610	610	500	530	530
H7T	115	Warkus JCT to Kidd Minesite CTS	580	700	730	500	640	670
H9K	115	Smooth Rock Fals JCT to H9K STR 127A JCT	360	360	360	270	270	270
H9K	115	Yellow Falls JCT to Yellow Falls CGS	560	560	560	470	470	480
H9K	115	Yellow Falls JCT to Fauquier JCT	420	420	420	360	360	360
H9K	115	Hunta H9K JCT to Smooth Rock Fals JCT	360	360	360	270	270	270
H9K	115	Smooth Rock Fals JCT to Smooth Rock Falls DS	430	510	570	370	470	530
H9K	115	Hunta SS to Hunta H9K JCT	1000	1200	1490	850	1100	1410
H9K	115	Carmichael Falls JCT to Carmichael Falls JCT	430	510	570	370	470	530
H9K	115	Spruce Falls JCT to Kapuskasing TS	1000	1100	1160	850	980	1050
H9K	115	Carmichael Falls JCT to Spruce Falls JCT	640	640	640	550	550	550
H9K	115	Fauquier JCT to Carmichael Falls JCT	430	510	560	370	470	520
H9K	115	Smooth Rk Fls JCT #2 to Yellow Falls JCT	420	420	420	360	360	360
H9K	115	H9K STR 127A JCT to Smooth Rk Fls JCT #2	430	510	570	370	470	530
H9K	115	Hunta H9K JCT to H9K STR 127A JCT	350	350	350	260	260	260
H9K	115	Fauquier JCT to Fauquier DS	430	510	570	370	470	530
H9K	115	Kapuskasing TS to Kapuskasing CTS	330	330	330	260	260	260
P13T	115	Porcupine TS to Timmins TS	1030	1180	1260	890	1060	1150
P15T	115	Porcupine TS to Timmins TS	1030	1250	1360	890	1140	1250
L5H	115	Otto Holden TS to Mattawa JCT	720	870	1020	620	790	960
L5H	115	Otto Holden TS to North Bay TS	630	630	630	420	420	420
L5H	115	North Bay TS to Commanda JCT	630	630	630	490	490	500
L5H	115	Commanda JCT to Crystal Falls SS	580	580	580	430	430	430
L5H	115	Commanda JCT to Commanda JCT	580	580	580	430	430	430
L5H	115	Commanda JCT to Commanda JCT	720	750	760	620	650	660
L5H	115	Mattawa JCT to North Bay TS	600	600	600	460	460	460
L5H	115	Mattawa JCT to Mattawa DS	430	510	520	370	470	480

Line	Voltage [kV]	Branch	Winter Continuous Rating [Amps]	Winter LTE Rating [Amps]	Winter STE Rating [Amps]	Summer Continuous Rating [Amps]	Summer LTE Rating [Amps]	Summer STE Rating [Amps]
L1S	115	Crystal Falls SS to Verner JCT	720	870	920	620	790	840
L1S	115	Verner JCT to Warren DS	720	870	920	620	790	840
L1S	115	Warren DS to Coniston TS	750	890	930	590	770	830
L1S	115	Coniston TS to Sudbury JCT	750	890	930	590	770	830
L1S	115	Sudbury JCT to Martindale TS	720	870	920	620	790	840
L1S	115	Sudbury JCT to Milman Foundry JCT	430	510	570	370	470	530
L1S	115	Verner JCT to Verner POLE 45 JCT	430	460	470	370	410	420
L1S	115	Verner POLE 45 JCT to Verner DS	430	510	570	370	470	530
L1S	115	Warren DS to Warren DS	330	330	330	260	260	260
L1S	115	Milman Foundry JCT to Milman Foundry CTS	430	510	570	370	470	530
L1S	115	Milman Foundry JCT to Milman Foundry CTS	430	510	570	370	470	530
D3K	115	Dymond TS to Nine Mile JCT	670	670	670	550	550	550
D3K	115	Nine Mile JCT to Dane JCT	670	670	670	550	550	550
D3K	115	Dane JCT to Gull Lake South JCT	670	670	670	550	550	550
D3K	115	Gull Lake South JCT to Kirkland Lake TS	670	670	670	550	550	550
K2	115	Kirkland Lake TS to Gull Lake North JCT	413	413	413	297	297	297
K2	115	Gull Lake North JCT to Gull Lake South JCT	540	540	540	420	420	420
K2	115	Gull Lake South JCT to Holloway Holt JCT	413	413	413	297	297	297
K4	115	Kirkland Lake TS to Macassa Mill JCT	315	315	315	228	228	228
K4	115	Macassa #3 JCT to 93K4-89 JCT	315	315	315	228	228	228
K4	115	Macassa #3 JCT to Macassa #3 JCT	330	330	330	260	260	260
K4	115	Matachewan JCT to Young-Davidson CTS	430	510	520	370	470	480
K4	115	93K4-89 JCT to Matachewan JCT	330	330	330	260	260	260
K4	115	Macassa Mill JCT to Macassa #3 JCT	315	315	315	228	228	228
K4	115	Macassa Mill JCT to Macassa Mill JCT	330	330	330	260	260	260
P91G	230	Porcupine TS to Erg Resources JCT	1300	1580	1800	1120	1440	1680
P91G	230	Erg Resources JCT to Hoyle JCT	1300	1580	1800	1120	1440	1680
P91G	230	Hoyle JCT to Kidd Metsite CTS	1300	1580	1800	1120	1440	1680
P91G	230	Hoyle JCT to Ansonville JCT	1300	1580	1780	1120	1440	1650
P91G	230	Ansonville JCT to Ansonville TS	1300	1580	1780	1120	1440	1650
D2H	115	Pinard TS to Pinard JCT #2	1110	1330	1500	950	1220	1400
D2H	115	Pinard JCT #2 to Hwy 634 JCT	650	650	650	500	500	500
D2H	115	Pinard JCT #2 to Hwy 634 JCT	650	650	650	500	500	500

Line	Voltage [kV]	Branch	Winter Continuous Rating [Amps]	Winter LTE Rating [Amps]	Winter STE Rating [Amps]	Summer Continuous Rating [Amps]	Summer LTE Rating [Amps]	Summer STE Rating [Amps]
D2H	115	Hwy 634 JCT to Island Falls JCT	650	650	650	500	500	500
D2H	115	Hwy 634 JCT to Island Falls JCT	650	650	650	500	500	500
D2H	115	Island Falls JCT to Greenwater Pr Pk JCT	650	650	650	500	500	500
D2H	115	Island Falls JCT to Greenwater Pr Pk JCT	650	650	650	500	500	500
D2H	115	Greenwater Pr Pk JCT to Calder JCT	650	650	650	500	500	500
D2H	115	Greenwater Pr Pk JCT to Calder JCT	650	650	650	500	500	500
D2H	115	Hunta JCT to Hunta SS	1270	1430	1560	1090	1280	1420
D2H	115	Hunta JCT to Hunta JCT	1000	1200	1490	850	1100	1410
D2H	115	Island Falls JCT to Island Falls JCT	1000	1200	1310	850	1100	1220
D2H	115	Greenwater Pr Pk JCT to Greenwater Pr Pk JCT	1000	1200	1310	850	1100	1220
D2H	115	Pinard JCT #2 to Pinard JCT #2	1110	1330	1500	950	1220	1400
D2H	115	Calder JCT to Calder JCT	1000	1200	1310	850	1100	1220
D2H	115	Calder JCT to Hunta JCT	650	650	650	500	500	500
D2H	115	Calder JCT to Hunta JCT	650	650	650	500	500	500
D2H	115	Calder JCT to Calder CSS	580	600	600	500	530	530
D3H	115	Pinard TS to Pinard JCT #2	1110	1330	1500	950	1220	1400
D3H	115	Pinard JCT #2 to Hwy 634 JCT	820	820	820	660	660	660
D3H	115	Pinard JCT #2 to Hwy 634 JCT	820	820	820	650	650	650
D3H	115	Hwy 634 JCT to Island Falls JCT	680	680	680	520	520	520
D3H	115	Hwy 634 JCT to Island Falls JCT	680	680	680	520	520	520
D3H	115	Island Falls JCT to Greenwater Pr Pk JCT	680	680	680	520	520	520
D3H	115	Island Falls JCT to Greenwater Pr Pk JCT	680	680	680	520	520	520
D3H	115	Greenwater Pr Pk JCT to Calder JCT	680	680	680	520	520	520
D3H	115	Greenwater Pr Pk JCT to Calder JCT	690	690	690	470	470	470
D3H	115	Hunta JCT to Hunta SS	1270	1430	1560	1090	1280	1420
D3H	115	Hunta JCT to Hunta JCT	1000	1200	1490	850	1100	1410
D3H	115	Island Falls JCT to Island Falls JCT	1000	1200	1490	850	1100	1410
D3H	115	Greenwater Pr Pk JCT to Greenwater Pr Pk JCT	1000	1200	1490	850	1100	1410
D3H	115	Pinard JCT #2 to Pinard JCT #2	1110	1330	1710	950	1220	1620
D3H	115	Calder JCT to Hunta JCT	680	680	680	520	520	520
D3H	115	Calder JCT to Hunta JCT	690	690	690	470	470	470
D3H	115	Calder JCT to Calder JCT	1000	1200	1310	850	1100	1220
K4	115	Kirkland Lake TS to Macassa Mill JCT	315	315	315	228	228	228
K4	115	Macassa #3 JCT to 93K4-89 JCT	315	315	315	228	228	228

Line	Voltage [kV]	Branch	Winter Continuous Rating [Amps]	Winter LTE Rating [Amps]	Winter STE Rating [Amps]	Summer Continuous Rating [Amps]	Summer LTE Rating [Amps]	Summer STE Rating [Amps]
K4	115	Macassa #3 JCT to Macassa #3 JCT	330	330	330	260	260	260
K4	115	Matachewan JCT to Young-Davidson CTS	430	510	520	370	470	480
K4	115	93K4-89 JCT to Matachewan JCT	330	330	330	260	260	260
K4	115	Macassa Mill JCT to Macassa #3 JCT	315	315	315	228	228	228
K4	115	Macassa Mill JCT to Macassa Mill JCT	330	330	330	260	260	260
D4	115	Pinard TS to Pinard JCT #2	1110	1330	1500	950	1220	1400
D4	115	Pinard JCT #2 to Abitibi Canyon GS	660	660	660	450	450	450
D4	115	Pinard JCT #2 to Abitibi Canyon GS	660	660	660	450	450	450
D6T	115	Pinard TS to Pinard JCT #2	1110	1340	1500	950	1220	1400
D6T	115	Pinard JCT #2 to Abitibi Canyn JCT #2	890	890	890	740	740	740
D6T	115	Pinard JCT #2 to Abitibi Canyn JCT #2	890	890	890	740	740	740
D6T	115	Abitibi Canyn JCT #2 to P Sutherland Sr JCT	680	680	680	570	570	570
D6T	115	Abitibi Canyn JCT #2 to Otter Rapids SS	700	700	710	530	530	530
D6T	115	P Sutherland Sr JCT to Otter Rapids SS	680	680	680	570	570	570
D6T	115	P Sutherland Sr JCT to P Sutherland Sr SYD	720	870	920	620	790	840
T8M	115	Otter Rapids SS to Moosonee SS	1000	1040	1070	850	910	940
T7M	115	Otter Rapids SS to Onakawana JCT	330	330	330	260	260	260
T7M	115	Onakawana JCT to Renison JCT	330	330	330	260	260	260
T7M	115	Renison JCT to Moosonee SS	330	330	330	260	260	260
T7M	115	Onakawana JCT to Onakawana CTS	330	330	330	260	260	260
T7M	115	Renison JCT to Renison CTS	330	330	330	260	260	260
M9K	115	Moosonee DS to Moosonee JCT	330	330	330	260	260	260
M9K	115	Moosonee JCT to Moosonee JCT	330	330	330	260	260	260
M9K	115	Moosonee JCT to Moosonee SS	330	330	330	260	260	260
M9K	115	Moosonee JCT to Moosonee DS	350	350	350	260	260	260
M9K	115	Moosonee JCT to Moosonee DS	350	350	350	260	260	260
R21D	230	Otter Rapids SS to Pinard JCT	1010	1010	1010	700	700	700
R21D	230	Otter Rapids SS to Pinard JCT	1010	1010	1010	700	700	700
R21D	230	Pinard JCT to Pinard TS	1330	1610	1810	1140	1470	1690
R21D	230	Pinard JCT to Abitibi Canyon GS	1020	1230	1510	880	1120	1430
R21D	230	Otter Rapids GS to Otter Rapids SS	1010	1010	1010	700	700	700
L20D	230	Little Long JCT to Smoky Falls JCT	1330	1610	1810	1140	1470	1690
L20D	230	Little Long JCT to Pinard TS	1330	1610	1810	1140	1470	1690
L20D	230	Little Long SS to Little Long JCT	1330	1610	1810	1140	1470	1690

Line	Voltage [kV]	Branch	Winter Continuous Rating [Amps]	Winter LTE Rating [Amps]	Winter STE Rating [Amps]	Summer Continuous Rating [Amps]	Summer LTE Rating [Amps]	Summer STE Rating [Amps]
L20D	230	Smoky Falls JCT to Harmon JCT	1330	1610	1810	1140	1470	1690
L20D	230	Harmon JCT to Kipling JCT	1380	1640	1840	1090	1440	1650
L20D	230	Kipling JCT to Kipling 2 GS	1420	1720	2000	1220	1570	1860
L20D	230	Harmon JCT to Harmon 2 GS	1420	1720	2000	1220	1570	1860
L20D	230	Smoky Falls JCT to Smoky Falls 2 JCT	1420	1720	2000	1220	1570	1860
D23G	230	Pinard TS to Pinard D23G JCT	1330	1610	1810	1140	1470	1690
H22D	230	Harmon GS to Harmon JCT	1330	1610	1810	1140	1470	1690
H22D	230	Harmon JCT to Smoky Falls JCT	1330	1610	1810	1140	1470	1690
H22D	230	Little Long JCT to Pinard TS	1330	1560	1730	1140	1410	1590
H22D	230	Little Long JCT to Little Long 2 JCT	1420	1720	2000	1220	1570	1860
H22D	230	Harmon JCT to Kipling JCT	1420	1720	2000	1220	1570	1860
H22D	230	Smoky Falls JCT to Little Long JCT	1330	1610	1810	1140	1470	1690
H22D	230	Kipling JCT to Kipling GS	1330	1610	1810	1140	1470	1690
H22D	230	Smoky Falls JCT to Smoky Falls 2 JCT	1420	1720	2000	1220	1570	1860
L21S	230	Little Long SS to Knob JCT	1020	1090	1120	880	960	1000
L21S	230	A.P. Kapuskasing JCT to Kapuskasing TS	1020	1130	1190	880	1010	1070
L21S	230	Knob JCT to A.P. Kapuskasing JCT	1020	1090	1120	880	960	1000
K38S	230	Kapuskasing TS to Spruce Falls JCT	1300	1580	1890	1120	1440	1780
K38S	230	Spruce Falls JCT to O'brien JCT	1020	1170	1240	880	1050	1130
K38S	230	Spruce Falls JCT to A.P. Kapuskasing JCT	1020	1170	1240	880	1050	1130
K38S	230	O'brien JCT to Spruce Falls TS	1020	1230	1510	880	1120	1430
K38S	230	O'brien JCT to Tembec Kapuskas CTS	1020	1230	1420	880	1120	1330
F1E	115	Kapuskasing TS to AP Calstock CSS JCT	580	610	620	500	540	540
F1E	115	Nagagami CSS JCT to Hearst TS	580	610	620	500	540	540
F1E	115	Kapuskasing TS to Spruce Falls TS	720	800	830	620	710	740
F1E	115	AP Calstock CSS JCT to A.P. Calstock CSS	540	540	540	420	420	420
F1E	115	AP Calstock CSS JCT to Nagagami CSS JCT	580	610	620	500	540	540
F1E	115	Nagagami CSS JCT to Nagagami CSS	430	430	430	340	340	340
T61S	115	Timmins JCT to Shiningtree DS	430	430	440	340	340	340
T61S	115	Timmins JCT to Ogden JCT	580	640	640	470	470	470
T61S	115	Ogden JCT to Timmins WestMine JCT	700	700	700	560	560	560
T61S	115	Timmins TS to Timmins JCT	600	710	820	480	620	740
T61S	115	Timmins WestMine JCT to Weston Lake DS	830	830	830	660	660	660

Line	Voltage [kV]	Branch	Winter Continuous Rating [Amps]	Winter LTE Rating [Amps]	Winter STE Rating [Amps]	Summer Continuous Rating [Amps]	Summer LTE Rating [Amps]	Summer STE Rating [Amps]
T61S	115	Timmins WestMine JCT to Timmins WestMine CTS	810	810	810	700	700	700
P7G	115	Porcupine TS to Dome Site JCT	1000	1200	1490	850	1100	1410
P7G	115	Dome Site JCT to Gold Centre JCT	720	870	1020	620	790	960
P7G	115	Ecstall JCT to Kidd Creek Mine JCT	1270	1490	1670	1090	1350	1530
P7G	115	Kidd Creek Mine JCT to Kidd Metsite CTS	1270	1490	1670	1090	1350	1530
P7G	115	Hoyle JCT to Hoyle Pond Site JCT	720	870	1020	620	790	960
P7G	115	Hoyle JCT to Hoyle DS	720	870	920	620	790	840
P7G	115	Pamour JCT to Hoyle JCT	750	890	1040	590	770	950
P7G	115	Hoyle Pond Site JCT to Ecstall JCT	720	870	1020	620	790	960
P7G	115	Gold Centre JCT to Bell Creek JCT	750	890	1040	590	770	950
P7G	115	Bell Creek JCT to Pamour JCT	750	890	1040	590	770	950
P7G	115	Bell Creek JCT to Bell Creek CTS	720	870	920	620	790	840
T2R	115	Timmins to Shiningtree Jct	610	610	610	510	510	510
T2R	115	Shiningtree Jct to Cote	1200	1387	1387	1040	1266	1266
H2N	115	Calstock DS JCT to Calstock DS	330	330	330	260	260	260

D.3 Credible Planning Events & Criteria

D.3.1 Studied Contingencies

Table 4 shows the contingencies assessed in the technical report.

Table 4 - Contingencies to be Assessed

Pre-contingency	Contingency[6]	Type	Mapping to TPL/Directory 1 Event	Rating[7]	Maximum Allowable Load Loss
All elements in-service	None	N-0	P0	Continuous	None
	Single	N-1	P1, P2	LTE	150 MW by-configuration
	Double	N-2	P7, P4, P5	STE, reduced to LTE	150 MW lost by curtailment; 600 MW Total[8]
All Transmission Elements in-service, local generation out-of-service, followed by system adjustments (Satisfy ORTAC 2.6 Re: local generation outage)	None	N-0	N/A	Continuous	None
	Single	N-G-1	P3	LTE	150 MW by-configuration; >0 MW lost by curtailment[9]; Total 150 MW
Transmission element out-of-service, followed by system adjustments	Single	N-1-1	P6	STE, reduced to LTE	150 MW lost by curtailment; Total 600 MW[5]

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

[7] LTE: Long-term emergency rating. 50-hr rating for circuits, 10-day rating for transformers.
STE: Short-term emergency rating. 15-min rating for circuits and transformers.

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

[9] Only to account for the magnitude of the generation outages

The specific single, common tower, and breaker failure contingencies studied are listed below. Note that:

- Transformer contingencies that result in the same post-contingency state as the N-1 already documented are omitted.
- The outage events used for the N-1-1 studies are similar to the N-1 contingencies documented in Table 4. However, they may be slightly different in some cases to reflect planned outages that involve the removal of a single element rather than all elements in a single zone of protection.

The specific single contingencies (N-1) studied are:

- A4H
- A5H
- A8K
- A9K
- ANSONVILLE T2
- C1C
- D23G
- D2H
- D2L
- D3H
- D3K
- D4Z
- D501P
- D6T
- DYMOND SC11
- F1E
- H22D
- H23S
- H24S
- H2N
- H4Z
- H6T
- H7T
- H9K
- HANMER SC21
- HANMER SC22
- HANMER T6
- HANMER T8
- HANMER T9
- HOLDEN T1
- HOLDEN T2
- HOLDEN T3
- HOLDEN T4
- K38S
- K4
- K2

- KAPUSKASING T5
- KAPUSKASING T6
- KIRKLAND LAKE T1
- L1S
- L20D
- L21S
- L5H
- L5H LEO@HOLDEN
- L8L
- M3K
- M9K
- MOOSONEE R1
- MOOSONEE R2
- P13T
- P15T
- P502X
- P91G
- PINARD K BUS
- PORCUPINE SC21
- PORCUPINE SC22
- PORCUPINE T3
- PORCUPINE T4
- PORCUPINE T7
- PORCUPINE T8
- R21D
- SPRUCE FALLS T7
- T2R
- T61S
- T7M
- T8M
- W71D
- X503E
- X504E
- A94N
- A93I
- D5H
- P7G
- PORCUPINE T1
- D4
- DES JOACHIMS T4
- TIMMINS T4
- TIMMINS T2

The specific common tower and breaker failure contingencies (N-2) studied are:

- A4H+A5H
- A8K+A9K
- ANSONVILLE H1L91
- ANSONVILLE L4L8
- ANSONVILLE L4L9
- ANSONVILLE L5L8
- ANSONVILLE L5LT2
- ANSONVILLE L9LT2
- DES JOACHIMS AL5
- DES JOACHIMS L1L5
- DYMOND AL2
- DYMOND AL3
- DYMOND L2L4
- DYMOND L3L4
- H22D+L20D
- H24S+W71D
- H6T+H7T
- H9K+K38S
- H9K+L21S
- HANMER JL502
- HANMER JL503
- HANMER PL503
- HANMER PL504
- HANMER W6L502
- HANMER W6L504
- HOLDEN AL23
- HOLDEN AL5
- HOLDEN DT3L5
- HOLDEN DT4L4
- HOLDEN KL23
- HOLDEN KL24
- HOLDEN L5L24
- HUNTA L2L5
- HUNTA L2L9
- HUNTA L3L7
- HUNTA L3L9
- HUNTA L4L6
- HUNTA L4L7
- HUNTA L5L6
- K38S+L21S
- KAPUSKASING 27H9K
- KAPUSKASING L1L9
- KAPUSKASING L21L38
- KASHECHEWAN L3B3
- KASHECHEWAN L9B3
- KIRKLAND LAKE D2D3

- KIRKLAND LAKE D2D8
- KIRKLAND LAKE D3D11
- KIRKLAND LAKE D4D11
- KIRKLAND LAKE D4D9
- KIRKLAND LAKE D8D9
- LITTLE LONG L20L21S
- MARTINDALE AL2
- MARTINDALE AL6
- MARTINDALE EA
- MARTINDALE EL1
- MARTINDALE HL1
- MARTINDALE L23T22
- MARTINDALE L24L26
- MARTINDALE PL23
- MARTINDALE TL24P
- MOOSONEE AL3
- MOOSONEE AL9
- MOOSONEE DL3
- MOOSONEE DL9
- OTTER RAPIDS L6L7
- OTTER RAPIDS L6L8
- P13T+P15T
- PINARD KL21
- PINARD KL22
- PINARD L20L21
- PINARD L2L4
- PINARD L2L6
- PINARD L3L4
- PINARD L3L6
- PINARD PL20
- PINARD PL22
- PORCUPINE H1L501
- PORCUPINE H1L502
- PORCUPINE H2L501
- PORCUPINE H2L502
- PORCUPINE HT7D1
- PORCUPINE HT7D2
- PORCUPINE HT8D1
- PORCUPINE HT8D2
- PORCUPINE K1K2
- PORCUPINE K1K4
- PORCUPINE K2K3
- PORCUPINE K3K4
- SPRUCE FALLS T7L1
- TIMMINS K1H6T
- TIMMINS K3H7T
- TIMMINS K3T61S

- WIDDIFIELD L71L23
- WIDDIFIELD L71L24

D.3.2 Planning Criteria

The study adheres to the following planning criteria:

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

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto,

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca **ieso.ca**

@IESO_Tweets
linkedin.com/company/IESO