# Integrated Regional Resource Plan Appendices

Northwest Region
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# Appendix A – Overview of 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 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 the OPA 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.

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[1] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf
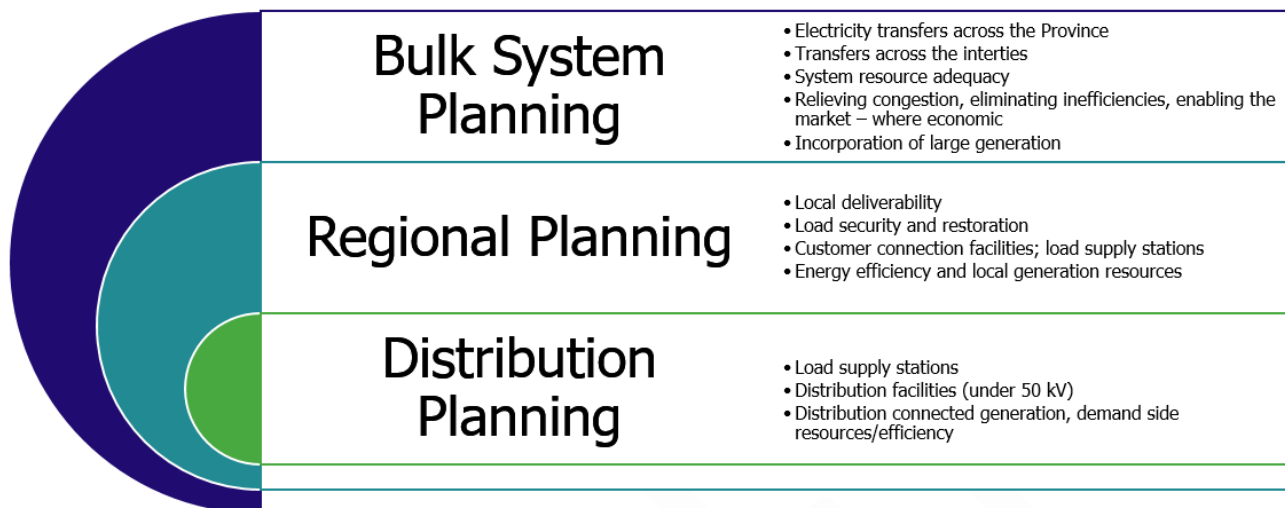
The regional planning process begins with a Needs Assessment process performed by the transmitter, which determines whether there are needs that should be considered for regional coordination.  If further consideration of the needs is required, the IESO conducts a Scoping Assessment to determine what type of planning should be carried out 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 1, three levels of electricity system planning are carried out in Ontario:

- Bulk system planning

- Regional system planning

- Distribution system planning

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

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

**Figure 1 | Levels of Electricity System Planning**

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

# Appendix B – Demand Forecast

Appendix B describes the methodologies used to develop the demand forecast (peak and duration) for the Northwest 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 sections that follow describe the weather correction methodology, the approaches and methods used by each LDC to forecast demand in their respective service area, and the conservation and DG assumptions.

## B.1 Method for Accounting for Weather Impact on Demand

Weather has a large influence on the demand for electricity, so to develop a standardized starting point for the forecast, the historic electricity demand information is weather-normalized. This section details the weather-normalization process used to establish the starting point for regional demand forecasts.

First, the historical loads were adjusted to reflect the median peak weather conditions for each transformer station in the area for the forecast base year (i.e. 2020 for the Northwest IRRP). Median peak refers to what peak demand would be expected if the most likely, or 50th percentile, weather conditions were observed. This means that in any given year there is an estimated 50% chance of exceeding this peak, and a 50% chance of not meeting this peak. The methodological steps are described in Figure 2.
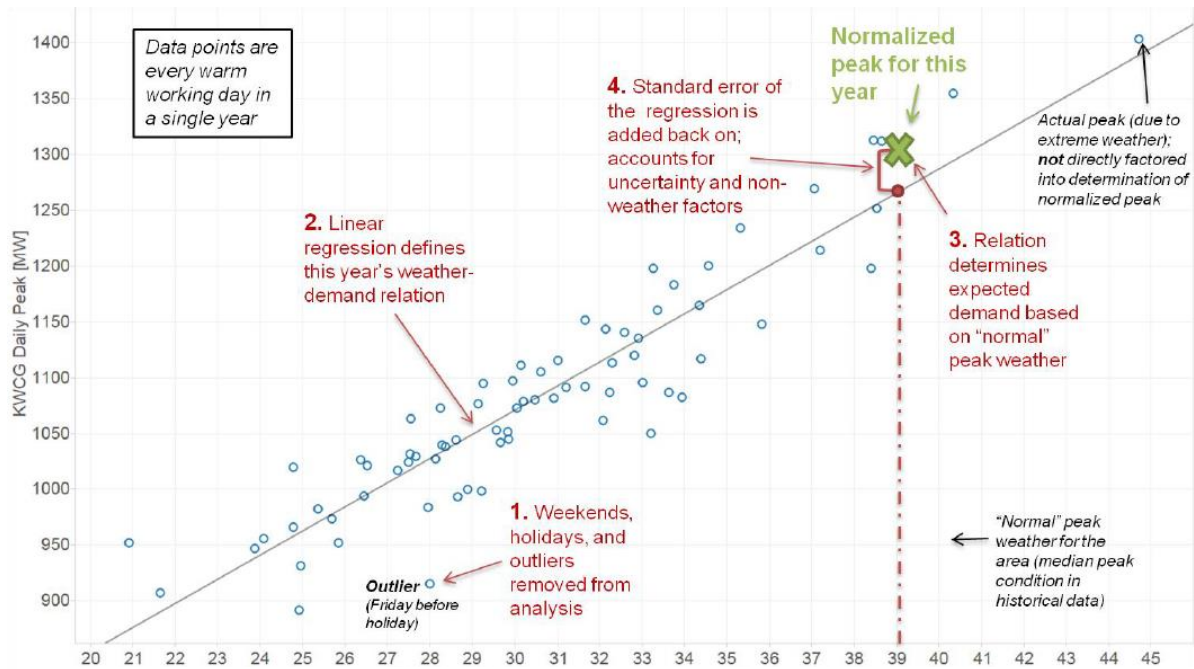
**Figure 2 | Method for Determining the Weather Normalized Peak (Illustrative)**

The 2018 median weather peak on a station and LDC load basis was provided to each LDC. This data was used as a start point from which to develop 20-year demand forecasts, using the LDCs preferred methodology (described in the next sections).

Once the 20-year horizon, median peak demand forecasts were returned to the IESO, the normal weather forecast was adjusted to reflect the impact of extreme weather conditions on electricity demand. The studies used to assess the adequacy and reliability of the electric power system generally require studies to be based on extreme weather demand, or, expected demand under the hottest weather conditions that can be reasonably expected to occur. Peaks that occur during extreme weather (e.g. summer heat waves in southern Ontario) are generally when the electricity system infrastructure is most stressed.

## B.2 Hydro One Forecast Methodology

Hydro One's demand forecast includes all areas in the Northwest region that are not reflect in the other distributors' service territories. The area served by Hydro One are mostly rural areas in the region. It is expected that the growth would occur mostly close to urban / built-up areas. Hydro One's forecast also includes demand from Sioux Lookout Hydro (embedded distributor).

Hydro One's conducts econometric and end-use forecasting. The main forecast drivers are Ontario GDP and housing starts. Load growth in the area relative to provincial trends was also taken into account. The following demand growth rate were assumed:

| Year | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| Growth Rate (%) | 4.5 | 4.2 | 2.2 | 2.0 | 2.1 | 2.0 | 1.9 | 1.8 | 1.8 | 1.8 |

| Year | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|
| Growth Rate (%) | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |

New developments where assumed to have an average demand of 4.5 kW per residential unit with non-electric heat source 14.5 kW per residential unit with electric heat source. Residential demand growth was estimated based on Ontario housing starts (in thousands) shown below:

| Year | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| Housing Starts | 75.2 | 76.5 | 77.0 | 76.9 | 75.3 | 69.9 | 69.6 | 69.2 | 68.6 | 68.6 |
| Year | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
| Housing Starts | 68.6 | 68.5 | 68.4 | 68.4 | 68.3 | 68.2 | 68.2 | 68.1 | 68.0 | 68.0 |

Provincial/regional development plans and known private/First Nations developments were taken into account.

## B.3 Fort Frances Power Forecast Methodology

Fort Frances Power Corporation ("Fort Frances Power") provides service to all consumers residing within the town of Fort Frances. Fort Frances is located approximately 300 km west of Thunder Bay, Ontario, approximately 250 km east of the Manitoba Border and is adjacent to the Town of International Falls, Minnesota, USA.  The town is located on the edge of the Canadian Shield and is subjected to extreme weather conditions including cold winters and hot summers.  The town is currently the third largest community of northwestern Ontario, after Thunder Bay and Kenora.

Fort Frances Power distributes electricity to approximately 3746 customers, over 32 square-kilometers, of which 88% are residential and 12% commercial.  The community receives its supply of electricity from a Hydro One Networks Inc. owned transmission line.  The transmission line supplies Fort Frances Power's transformer station Fort Frances MTS with a single 115 kV point of supply.  The Fort Frances MTS transformer station steps down the incoming transmission supply to a distribution voltage of 12.47 kV, which is the primary distribution voltage of the entire distribution network within Fort Frances.

The Fort Frances MTS transformer station is the heart of the electrical distribution system for Fort Frances and will require considerable reinvestment over the next 10 to 15 years.  The station was built in the early 1970s with some components being manufactured in the 1960s.  The station and is projected to reach the end of its useful service life by 2034.  Fort Frances Power is currently in the early stages of planning a complete transformer station rebuild over the next 10 – 15 years.  The planned rebuild will also address potential load growth as well as customer reliability concerns associated the station being supplied from a single point of supply.  Fort Frances Power is working with Hydro One Networks Inc. to bring a second point of supply to the station which would essentially eliminate Loss of Supply type outages that account for more than 90% of all customer interruption hours.

**Factors that Affect Electricity Demand**

Over the next 20 years, changes to electricity demand for Fort Frances are expected to be dependent on several factors including weather/climate conditions, the economic prosperity of the community, and government policy. 2022 year-to-date metering data indicates increases of 4.8% in electricity consumption and 3.1% in electricity demand, relative to 2021.

Fort Frances has a relatively extreme humid continental climate with bitterly cold winters and temperate summers. Temperatures beyond 34 degrees Celsius have been measured in all five late spring and summer months. Summer highs are comparable to Paris and the Los Angeles Basin coastline in California, whereas winter lows on average resemble southern Siberia and polar subarctic inland Scandinavia. As such Fort Frances is a winter peaking region with more electricity being consumed for the purpose of heating as opposed to cooling. A significant number of customers still use electric heat as their primary heat source due to natural gas only becoming available in the 1990s. Prolonged periods of hot or cold weather have a considerable impact on local electricity demand. Fort Frances Power anticipates that electric heat related demand will remain relatively stable with modest growth due to the increasing affordability of electricity in Fort Frances versus natural gas. The community currently enjoys among the lowest rates for electricity in all of Ontario, which makes electric heat more attractive than in other parts of the Province. Government policy such as carbon taxation and the new ultra-low overnight electricity rate are expected to drive consumer fuel switching from natural gas to electricity. Consumers switching appliances such as furnaces and hot water tanks from natural gas over to electricity is expected to result in modest increases to electricity demand.

The economic prosperity of Fort Frances is anticipated to have the most impactful affect on electricity demand for the community. The community suffered a temporary downturn in 2014 due to the permanent closure of the local pulp and paper mill, resulting in the loss of over 800 direct jobs. The impact from the closure was partially mitigated by the start-up of the New Gold Rainy River Mine just west of Fort Frances in 2017. Considerable effort is being exerted towards sparking new economic development in Fort Frances, and towards the rebuilding a commercial and industrial employment base. The town has received proposals from a variety of investors regarding economic development initiatives, however, they are not included in the forecast as no firm commitments have been received to date.

The electrification of transportation is also anticipated to have a significant affect on increasing the demand for electricity in Fort Frances. Again, government policy such as electric vehicle rebates could have a significant impact on the adoption rate of electric vehicles, however, it is difficult to quantify the overall impact at this time.

**Forecast Methodology and Assumptions**

Historical peak demands from the years 2016 to 2020 were used to calculate Fort Frances Power's 2021 base (starting point) Peak Demand of 15.2 MW at its transformer station Fort Frances MTS. The 2021 starting point was found by calculating the slope and intercept of the historical peaks and calculating the "projected" 2020 value. The following factors were taken into consideration for the establishment of the 0.5% year-over-year projected increase in demand.

- Embedded Generation: 0% - Peak demands are usually set throughout the extremely cold winter nights, at times where no Photo Voltaic Embedded Generation is being produced.
- Annual Growth Factor: 0.5% - Conservative growth factor, taking into account electric vehicle adoption, natural gas to electricity fuel switching, and increasing customer base.
- Large Commercial/Industrial Developments: 0% - Could have the potential for significant demand increase, however, set to 0% as no firm commitments have been made to date.

## B.4 Atikokan Hydro Forecast Methodology

Atikokan Hydro Inc. ("Atikokan Hydro") provides service to the Township of Atikokan.

Atikokan Hydro distributes electricity to approximately 1630 customers, over 320 square kilometers, of which 85% are residential and 15% are commercial. Commercial customers make up over 50% of Atikokan's base load.

Electricity is transmitted from Hydro One Network's Moose Lake TS to Atikokan Hydro's substations via Atikokan Hydro's two 44 KV circuits; comprised of the 3M2 and 3M3. Atikokan Hydro has three substations in the most densely populated customer area that distributes the electricity at 8320/4800 volts.  Atikokan Hydro's distribution system then delivers electricity at the appropriate voltage to residential and commercial customers. Atikokan Hydro territory has both rural and urban; totaling 92 km of line that serves the Town of Atikokan.

Factors that Affect Electricity Demand

Atikokan Hydro is a winter peaking utility with a pelletizing plant representing a significant portion of base load demand. There are no new local developments projected to significantly drive electricity requirements. Potential for slight increase as a result of local expansions and development of potential new construction but no certainty or known details of impacts to load at this time.

There is no forecast load reduction, but if Atikokan's pelletizing plant were to shut down, the forecast could change significantly as a significant portion of the electricity demand is associated with the plant.  Of recent, no reduction to electrical demand other than CDM savings and a decline in customer accounts due to abandoned buildings and an aging population.

All demographic and economic conditions have been assumed to remain status quo. Trends in population have been declining. Statistics Canada Census profile indicates Atikokan with a population of 3,293 in 2006 and a population of 2,642 in 2021. This represents nearly a 20% decline in overall population in the community. Any growth potentials break even with a reduction in customers.

Forecast Methodology and Assumptions

Atikokan Hydro's forecast was developed by examining historical actual system peak load data for each year and applying local knowledge of any known economic developments. Historically new development has not driven the local electricity demand.

The peak demand historically has been impacted by the forestry industry in Ontario. The main factors affecting forecast and loads has been the closure of sawmills and a particle board plant, and re-opening of an existing plant. The geographical location and resources of our community limits the growth opportunities. The industry can be volatile and significantly impact with abrupt changes.

For forecast purposes, stability and current load was assumed.

2022 is forecasted to increase to 5.88 mw which is the four-year historical average of 2016 through 2019 (2020 was excluded due to the anomaly of COVID-19). This assumes COVID impacts have flattened, and electrical consumption and demands are closer if not back to normal levels and Atikokan has some new load from new build construction underway (multi-residential building and renovation and expansion of a school). New load is not believed to significantly change the overall Atikokan load based on the knowledge the LDC has. 2023 is forecasted to have a 1% influx from the year prior for potentials of other construction underway assuming the remainder of buildings, facilities and commercial establishments maintain status quo. 2025 assumed to reach 6 mw and assumed to plateau at 6 mw with no evidence of other significant load impacts. 6 mw is achievable based on historical loads and knowledge of local economic developments. It can additionally be accommodated under the current transformer ratings.

## B.5 Synergy North Forecast Methodology

1. Background Information

1.1. Historic Peak information

Load transfers are a regular occurrence in the operation of the system in Thunder Bay. Load is frequently moved from one station to another for routine maintenance or during abnormal conditions. Although some of the peaks coincide with load transfers, it can be expected that load transfers will occur in any given year. Kenora MTS is a radial feeder and does not have capabilities to perform any load transfers.

1.1.1. Birch TS

2016 through 2019 peaks for Birch TS all occurred under normal operating conditions. The 2020 peak occurred during a temporary load transfer of a section feeder 2M4 (normally PATS) fed by 17M2 from Birch TS for scheduled maintenance by Hydro One at PATS.

1.1.2. Fort William TS

2016 through 2018 and 2020 peaks for FWTS all occurred under normal operating conditions. The 2019 peak occurred during scheduled maintenance on Birch TS T3. FWTS feeder 10M3 was used to pick-up a section of 17M1 normally fed by Birch TS.

1.1.3. Port Arthur TS

The 2016 peak occurred during a load transfer of 17M5 (normally BRTS) to 2M3 on PATS due to an issue at an LDC DS. The 2017 peak occurred during a load transfer of 17M5 (normally BRTS) to 2M2 on PATS due to maintenance at BRTS. The 2018 peak occurred during normal operating conditions. The 2019 peak during a load transfer of 17M2 (normally BRTS) to 2M4 on PATS due to T3 maintenance at BRTS. The 2020 peak occurred during a load transfer of 17M5 (normally BRTS) to 2M5 on PATS due to a protection update for the feeder at Birch.

1.1.4. Kenora MTS

All the peaks for the station occurred during normal operating conditions. Kenora MTS does not have capability to transfer load as it is on a radial feed.

1.2. Electrical Load in Study Area

100% Synergy North's load is within the study area for the Integrated Regional Resource Plan for the Northwest Region.

1.3. Market and Rate Segmentation of Load

| Station | Residential Customers | Commercial Customers | Industrial Customers | Total Customers |
|---|---|---|---|---|
| Birch TS | 14,617 | 2,078 | 5 | 16,700 |
| Fort William TS | 22,300 | 2,103 | 7 | 24,410 |
| Port Arthur TS | 8,879 | 735 | 3 | 9,617 |

Note: Rate segmentation only available by customer counts and not MW. No data available for Kenora MTS.

2. Methodology

- Hourly net load and generation data was gathered from 2010 to 2020.

  o Aggregate micro and small generation data were split among stations based on percentage of allocated capacity at the station in relation the total.

- CDM program data and generation were added to the net load data to determine gross peaks.

  o CDM program benefits were carried from year to year with a considered depreciation value of 5% per year.

  o No new CDM was added for the forecast period, although depreciated existing CDM was included in gross totals.

- Monthly peaks were plotted against the average monthly temperature to generate a 3rd order polynomial line of best fit for weather dependence at each station.

- o The gross data was normalized for weather by subtracting the weather dependence per the 3rd order polynomial.

- o Multi-linear regression was performed on the weather normalized monthly gross load data using economic factors selected based on R2 correlation values to provide a model based on predicted factors. These factors include grain prices index, Thunder Bay unemployment rate, metal prices index, Thunder Bay CPI and Canada unemployment rate.

- Weather was added back into the forecast using the 3rd order polynomials per station and the assumed average monthly temperatures over the past 10 years to create the monthly forecast models.

- Modest growth factors were then added to forecast model to account for future development.

  - o 0.5% for Birch TS

  - o 0.5% for Fort William TS

  - o 0.5% for Port Arthur TS

  - o 1.25% for Kenora MTS (higher for Kenora as more interest in development)

- The annual gross peak was then determined from the final model.

- Note that the numbers provided were based on gross load (including DG and CDM) and the actual station peak demand provided did not include most DG or CDM.

3. Drivers of Load Growth

The municipal growth plan for Thunder Bay was high level and did not go into enough specifics to speculate on future load. No specific large load projects have been applied for in Synergy North's service territory at this time and therefore no specific project is included in the forecast. We have had interest from potential customers about future projects (including a possible 4MW project in Kenora), but no formal agreements have been signed. We have decided to roll these projects into the modest growth factors applied.

4. Behind the Meter Generation

No new behind the meter generation projects are currently in progress. Therefore, none have been included in the forecast. There has been some interest from proponents, but no connection impact assessments are currently underway. We have experienced a significant drop in all embedded generation applications including micro sized projects with the end of the FIT program. Two existing CHP load displacement generation projects connected to BRTS at 2.0MW and 1.984MW (3.984MW total) have been added to the effective winter capacity sheet.

5. EV Adoption

Synergy North used the 2020 Annual Planning Outlook (APO) as a base to predict the average hourly MW increase for the province, then applied that value to Thunder Bay and Kenora based on population as a portion of the provincial population. As the loads for EV's were expected to occur during non-peak times mainly, the average hourly increase was determined to be appropriate and was added to the original peak load forecast to come up with the attached high electrification forecast.

## B.6 Projects Included in IRRP Mining Sector Forecast

The lists below reflect known projects as of Q4 2021.

Existing Active Mines in the Northwest Region

| Mine Name | Owner | Location | Peak Demand | End date | Information Source |
|---|---|---|---|---|---|
| Helmo Property Mines | Barrick Gold Cop | Marathon | Known | 2029 | MDNM, Generation Mining Data Online, |
| Musselwhite Mine | Newmont Goldcorp | Pickle Lake | Known | 2030 | Generation Mining Data Online |
| Rainy River Mine | New Gold | Fort Frances Nestor Falls | Known | | |
| Red Lake Complex | Evolution Mining | Red Lake | Known | 2033 | Generation Mining Data Online, Company Web site |
| Lac Des Iles Palladium Mine | Impala Canada Limited | Thunderbay | Known | 2030 | Generation Mining Data Online |
| PureGold (Madsen) Gold Mine | Pure Gold Mining | Red Lake | Known | 2031 | Generation Mining Data Online |
| Sugar Zone Mine | Harte Gold | Marathon | Known | 2033 | Generation Mining Data Online, Company Web site |

Future Mines and/or Mining Exploration in the Northwest Region

| Project Name | Owner | Location | Peak Demand | i/s | o/s | Information Source |
|---|---|---|---|---|---|---|
| Greenstone Gold Mines Project | Orion Mine/Premier Gold Mines | Greenstone | Known | 2021 | 2036 | CVNW, OMED |
| Battle North (Bateman) Gold Project | Evolution Mining | Red Lake | Known | 2021 | 2030 | CVNW, OMED, Hydro One |

| Project | Company | Location | Status | Start | End | Source |
|---|---|---|---|---|---|---|
| Marathon PGM-CU Project | Generation Mining | Marathon | Known | 2024 | 2040+ | CVNW, OMED, Hydro One |
| Hammond Reef Gold Project | Agnico - Eagle | Atikokan | Known | 2025 | 2036 | CVNW, Hydro One |
| Springpole Gold Project | First Mining Finance | Cat Lake | Known | 2025 | 2035 | CVNW, OMED, Hydro One |
| Eagle's Nest | Noront | Ring of Fire | Known | 2025 | 2035 | CVNW, OMED |
| Black Bird | Noront | Ring of Fire | Known | 2028 | 2037 | CVNW |
| Goliath Gold Project | Treasure Metals | Dryden | Known | 2024 | 2033 | CVNW, OMED |
| PAK Lithium Project | Frontier Lithium | Red Lake | Known | 2025 | 2040+ | CVNW, OMED, Hydro One |
| Moss Lake Project | Wesdome Gold | Thunderbay | Known | 2025 | 2034 | CVNW |
| AMI Project | Ambershaw Metallics | Ignace | Known | 2025 | 2040+ | CVNW |
| Separation Rapids Project | Avalon Advanced Metals | Kenora | Known | 2025 | 2040+ | CVNW, OMED |
| Georgia Lake Project | Rock Tech Lithium | Thunderbay | Known | 2026 | 2040+ | CVNW |
| Cameron Gold Project | First Mining Finance | Nestor Falls | Known | 2026 | 2040+ | CVNW, OMED |
| Winston LK Project | CROPS | Marathon | Known | 2026 | 2040+ | CVNW, OMED, Hydro One |
| Thunder Bay North PGM Project | Clean Air Metals | Thunder Bay North | Known | 2029 | 2040+ | CVNW, OMED, Hydro One |
| Theirry Project | Cadillac Ventures | Pickle Lake | Known | ? | ? | OMED |
| Albany Project | Zen Graphene | Hearst | Known | ? | ? | CVNW, OMED |
| Eagle Island/St Joseph Project | Rockex Mining Corp | NoD | Known | ? | ? | CVNW |
| Griffith | Lithium Energy Products | NoD | Known | ? | ? | CVNW |
| Sturgeon Lake Project | Glencore/Odin/FQML | Ignace | ? | ? | ? | Company's website |
| Dixie Project | Great Bear Resources | Red Lake | ? | ? | ? | CVNW |
| Mt. Jamie North Gold Project | Stone Gold | Red Lake | ? | ? | ? | Company's website |
| Sunday Lake Project | Transition Metals | Thunder Bay | ? | ? | ? | CVNW |
| Rowan Mine Project | West Red Lake Gold | Red Lake | ? | ? | ? | Company's website |

| Horseshoe Island Project | First mining Gold | Red Lake | ? | ? | ? | Company's website |
|---|---|---|---|---|---|---|
| Kyle Lake (U2 Kimberlite) Project | Metalex Ventures | ? | ? | ? | ? | OMED |

## B.7 IRRP Mining Demand Forecast Scenarios

The IRRP mining sector demand forecast scenarios can be found in the accompanying Excel spreadsheet Table B.8.

## B.8 Conservation and Demand Management Assumptions

Energy efficiency measures can reduce the electricity demand and their impact can be separated into the two main categories: Building Codes & Equipment Standards, and Energy Efficiency Programs. The assumptions used for the Northwest IRRP forecast are consistent with the energy efficiency assumptions in the IESO's 2020 Annual Planning Outlook including the 2021 – 2024 CDM 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 Northwest IESO transmission zone and then allocated to the Northwest region. This appendix describes the process and methodology used to estimate energy efficiency savings for the Northwest region and provides more detail on how the savings for the two categories were developed.

### B.8.1. Estimated 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 Northwest zone and compared with the gross peak demand forecast for each zone. From this comparison, annual peak reduction percentages were developed for the purpose of allocating the associated savings to each station in the region, as further described below.

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 6.6% peak demand savings through codes and standards. The same is done for the commercial sector, which will see about 0.8% 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.8.2. Estimated Savings from Energy Efficiency Programs

In addition to codes and standards, the delivery of CDM programs reduces electricity demand. The impact of existing and planned CDM programs were analyzed, which include the 2021 – 2024 CDM Framework, the existing federal programs, and the forecasted long term energy efficiency programs. A top down approach was used to estimate the peak demand reduction due to the delivery of these programs, from the province, to the Northwest zone, and finally to the stations 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 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 Northwest zone. They were then applied to the sectoral gross peak forecast of each station in the region. By 2030, 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 1.6% and 1.9% peak reduction respectively.

### B.8.3. Total Energy Efficiency Savings and Impact on the Planning Forecast

As described in the above sections, peak demand savings were estimated for each sector, and totalled for each station in the region. The analyses were conducted under normal weather conditions and can be adjusted to reflect extreme weather conditions. The resulting forecast savings were applied to gross demand to determine net peak demand for further planning analyses.

The IRRP CDM forecast for each station can be found in the accompanying Excel spreadsheet Table B.9.3.

## B.9 Installed Distributed Generation and Contribution Factor Assumptions

The distributed generation contribution factor assumptions station can be found in the accompanying Excel spreadsheet Table B.10.1. The distributed generation output assumptions for each station can be found in Table B.10.2.

## B.10 Final Peak Forecast by Station

The final peak station-level demand forecast can be found in the accompanying Excel spreadsheet Table B.11.

# Appendix C – Northwest IRRP Technical Study

## C.1 Description of Study Area

The Northwest region bounded by Marathon TS to the east and the Minnesota and Manitoba interties to the west. The 230 kV system is comprised of the following lines and stations: WxM lines from Wawa TS to Marathon TS, the MxL lines from Marathon TS to Lakehead TS, the AxL lines from Lakehead TS to Mackenzie TS, and Mackenzie TS-Dryden TS-Kenora TS-Fort Frances TS loop formed by the D26A/K23D/K24F/F25A lines. A new 230 kV circuit, W54W, was recently added between Dinorwic Junction (near Dryden TS on D26A) and Wataynikaneyap TS near Pickle Lake. Interconnections to Minnesota and Manitoba are provided via F3M from Fort Frances TS and K21W/K22W from Kenora TS, respectively. The Northwest region also includes 230/115 kV autotransformers each of the 230 kV stations listed above and the respective 115 kV subsystems supplied from these autotransformers.  A single line diagram of this region is shown in Figure 3 below.

### C.1.1 Load Forecast

The initial need identification study used net winter extreme weather forecast snapshots in 2023, 2027, 2032, and 2040 (end of planning horizon). The station level forecast is provided in Appendix B.7 and B.11 above. The 2027 snapshot has the highest overall regional peak load because the mining sector forecast peaks in 2027 and declines thereafter.

A power factor of 0.90 was assumed unless there was specific information indicating that a higher power factor assumption was appropriate. An 0.95 power factor was assumed for Crilly DS loads (consistent with historical and expected future load characteristics) for the purpose of determining the station capacity need date. An 0.9 power factor was assumed for all other stations.
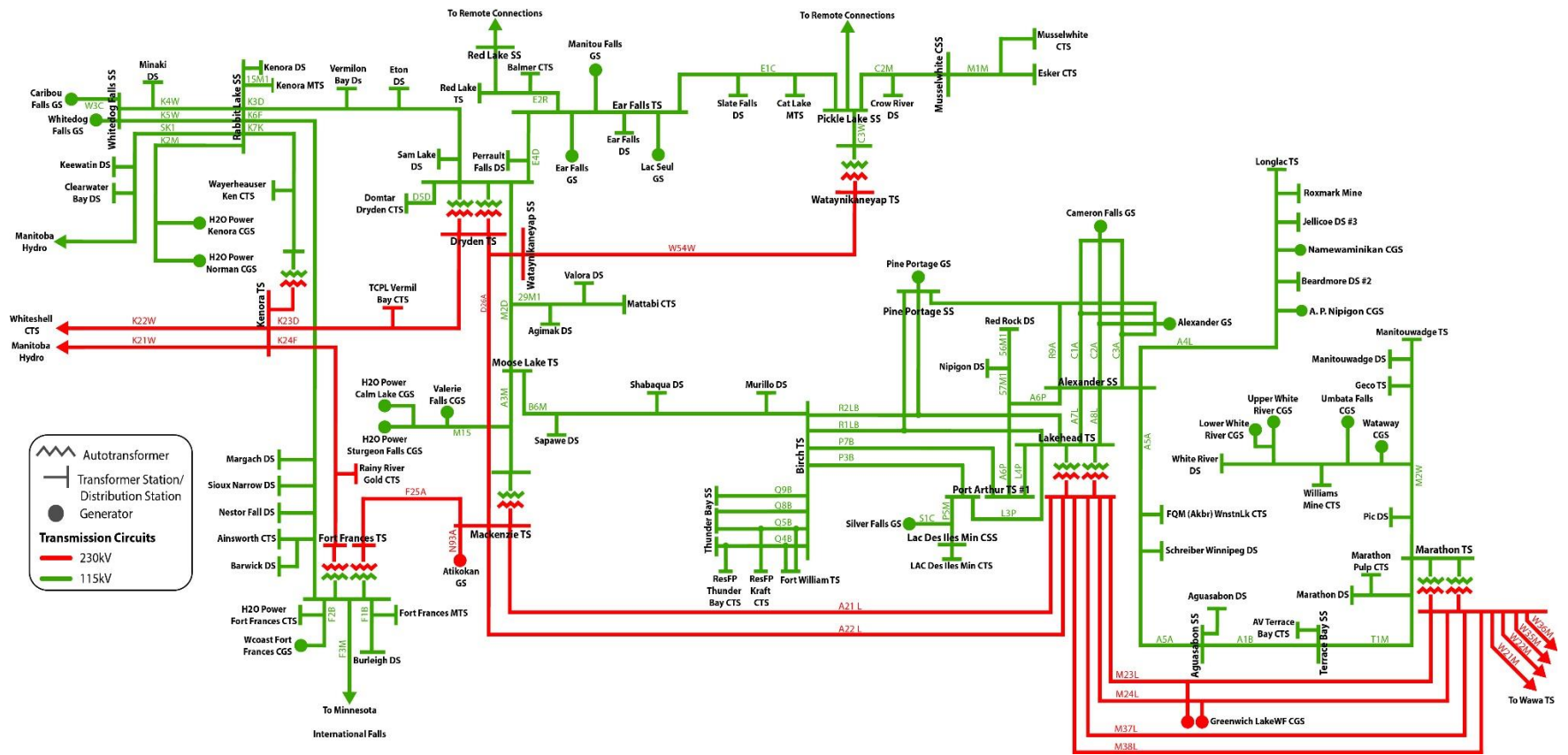
**Figure 3 | Single Line Diagram of the Northwest Region**

## C.1.2 Local Generation Assumptions

Dependable 98th percentile and 85th percentile hydro generation output is tabulated in Table 1. All-in-service base cases used 98th percentile dependable hydro (consistent with ORTAC criteria) while outage condition base cases used 85th percentile hydro (consistent with historical best practices). Note that numbers in Table 1 are non-coincident (i.e. each facility at their individual 98th/85th percentile output). Coincident dependable hydro for any given subsystem (i.e. several facilities' combined 98th/85th percentile output) will usually be higher than the sum of the non-coincident output at each facility within the subsystem.

**Table 1 | Dependable Hydro Assumptions (Non-Concident) in the Northwest Region**

| Hydro Facility | Winter 98th (MW) | Winter 85th (MW) | Summer 98th (MW) | Summer 85th (MW) |
|---|---|---|---|---|
| ABKENORA | 8.6 | 9.5 | 0.4 | 4.7 |
| AGUASABON | 11.0 | 29.7 | 0.0 | 11.3 |
| ALEXANDER | 39.0 | 41.6 | 24.6 | 26.7 |
| CALMLAKE | 6.9 | 8.1 | 3.3 | 5.9 |
| CAMERONFALLS | 47.0 | 53.1 | 27.4 | 32.8 |
| CARIBOUFALLS | 43.4 | 66.6 | 7.8 | 29.0 |
| EARFALLS | 16.9 | 21.5 | 4.9 | 10.9 |
| FORTFRANCS | 3.3 | 4.7 | 4.0 | 4.1 |
| KAKABEKA | 9.0 | 14.6 | 1.7 | 5.4 |
| LOWERWHITE | 3.5 | 4.4 | 2.2 | 2.5 |
| MANITOUFALLS | 43.0 | 50.7 | 7.3 | 22.9 |
| MANITOUWATS | 0.2 | 0.5 | 0.0 | 0.1 |
| NAMEWAM | 2.3 | 2.7 | 0.0 | 0.4 |
| PINEPORTAGE | 45.6 | 74.3 | 14.5 | 39.5 |
| SILVERFALLS | 30.6 | 32.9 | 0.0 | 0.0 |
| STURGEONFALL | 4.9 | 6.6 | 2.2 | 4.3 |
| UMBATAFALLS | 5.0 | 8.6 | 1.8 | 4.2 |
| UPPERWHITE | 3.1 | 3.1 | 1.9 | 3.4 |
| VALRIEFALLS | 2.9 | 4.5 | 0.4 | 1.6 |
| WAWATAY | 1.2 | 2.5 | 0.2 | 1.1 |
| WHITEDOG | 22.5 | 38.6 | 6.3 | 27.6 |
| **Total Non-Coincident** | 348.3 | 478.8 | 111.1 | 238.3 |
| **Total Coincident** | 481.3 | 512.0 | 268.8 | 317.4 |

Table 2 below shows the non-hydro transmission-connected generation. Atikokan GS and Nipigon GS were assumed to be out-of-service since their current contract term date ends in the near term. Greenwich Lake Wind Farm was also assumed to be out-of-service for simplicity but this generator does not materially impact the IRRP study since it is connected along the MxL East-West Tie (EWT) lines. While Greenwich Lake Wind Farm does impact the overall flow along the EWT, the EWT transfer capability was not in scope for the IRRP and the wind farm does not impact any of the local subsystems' load meeting capability.

**Table 2 | Non-Hydro Transmission-Connected Generation in the Northwest Region**

| Facility Name | Contract Capacity | Term Start Date | Term End Date |
|---|---|---|---|
| Atikokan GS | 205 MW | 2014 | 2024 |
| Nipigon GS | 16 MW | 2018 | 2022 |
| Greenwich Lake Wind Farm | 99 MW | 2011 | 2031 |

Note that the tables above do not include distribution-connected generation nor generation at transmission-connect customer stations. Distribution-connected generation are accounted for directly in the demand forecast. There is no contractual mechanism to rely on generation at transmission-connected customer stations for capacity during peak demand conditions.

**---- End of Section ---**

## C.2 System Topology

### C.2.1 Monitored Circuits and Stations

Table 3 lists the monitored transformers station in the Northwest Region.

**Table 3 | Monitored Stations in the Northwest Region**

| Station Names | |
| --- | --- |
| Agimak DS | Margach DS |
| Ainsworth CTS (Voyageur CTS) | Minaki DS |
| Balmer CTS | Moose Lake TS |
| Barwick TS | Murillo DS |
| Beardmore DS #2 | Musselwhite CTS |
| Birch TS | Musselwhite CTS |
| Bowater Thunder Bay CTS | Nestor Falls DS |
| Burleigh DS | Nipigon DS |
| Cat Lake MTS | Perrault Falls DS |
| Clearwater Bay DS | Pic DS |
| Crow River DS | Port Arthur TS #1 |
| Dryden TS | Rainy River CTS (Rainy River Gold CTS) |
| Ear Falls TS | Red Lake TS |
| Esker CTS | Red Rock DS |
| Eton DS | Sam Lake DS |
| Fort Frances MTS | Sapawe DS |
| Fort Frances TS | Schreiber Winnipeg DS |
| Fort William TS | Shabaqua DS |
| Geco Mines Xstrata CTS | Sioux Narrows DS |
| Jellicoe DS #3 | Slate Falls DS |
| Keewatin DS | TCPL Vermillion Bay CTS |
| Kenora MTS | Teck Corona CTS (Williams Mine CTS) |
| Kenora TS | Terrace Bay CTS |
| Lac des Iles Mine CTS | Valora DS |
| Lakehead TS | Vermilion Bay DS |
| Longlac TS | Wataynikaneyap TS |
| Mackenzie TS | Wayerheauser Dryden CTS |
| Manitouwadge DS #1 | Wayerheauser Ken CTS |
| Manitouwadge TS | White River DS |
| Marathon DS | Winston Lake CTS |
| Marathon TS | Xstrata Mattibi Mine CTS |

Table 4 lists the monitored circuits in the Northwest Region. Note that the summer ratings have in Table 4 have not been updated to reflect the latest 35 degree ratings which were introduced during the IRRP. Since the IRRP technical studies were already underway, the initiate needs identification studies were not repeated with the new ratings but, where thermal constraints were identified, the new 35 degree ratings were used to determine the load meeting capability.

**Table 4 | Monitored Circuits and Ratings**

| Circuit | Section | From | To | Winter Ratings (A) | | | Summer Ratings (A) | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Cont | LTE | STE | Cont | LTE | STE |
| A1B | 1 | Aguasabon SS | AV Terrace Bay JCT | 680 | 680 | 680 | 570 | 570 | 570 |
| A1B | 2 | AV Terrace Bay JCT | Terrace Bay SS | 720 | 870 | 1020 | 620 | 790 | 960 |
| A1B | 3 | AV Terrace Bay JCT | AV Terrace Bay CTS | 720 | 870 | 1020 | 620 | 790 | 960 |
| A21L | 1 | Mackenzie TS | Lakehead TS | 1020 | 1020 | 1020 | 880 | 880 | 880 |
| A21L | 1 | Mackenzie TS | Lakehead TS | 1020 | 1020 | 1020 | 880 | 880 | 880 |
| A22L | 1 | Mackenzie TS | Lakehead TS | 1020 | 1020 | 1020 | 880 | 880 | 880 |
| A22L | 1 | Mackenzie TS | Lakehead TS | 1020 | 1020 | 1020 | 880 | 880 | 880 |
| A23P | 1 | Algoma TS | Mississagi TS | 1020 | 1230 | 1510 | 880 | 1120 | 1430 |
| A24P | 1 | Algoma TS | Mississagi TS | 1020 | 1230 | 1510 | 880 | 1120 | 1430 |
| A4L | 1 | Alexander SS | A4L STR 217 JCT | 390 | 390 | 390 | 310 | 310 | 310 |
| A4L | 2 | Beardmore JCT | Namewaminikan JCT | 330 | 330 | 330 | 260 | 260 | 260 |
| A4L | 6 | Jellicoe DS #3 JCT | Longlac TS | 330 | 330 | 330 | 260 | 260 | 260 |
| A4L | 7 | Beardmore JCT | Beardmore DS #2 | 430 | 510 | 570 | 370 | 470 | 530 |
| A4L | 10 | A.P. Nipigon JCT | Beardmore JCT | 390 | 390 | 390 | 310 | 310 | 310 |
| A4L | 11 | A.P. Nipigon JCT | A.P. Nipigon CGS | 580 | 600 | 610 | 500 | 530 | 530 |
| A4L | 12 | Jellicoe DS #3 JCT | Jellicoe DS #3 | 330 | 330 | 330 | 260 | 260 | 260 |
| A4L | 13 | Namewaminikan JCT | Jellicoe DS #3 JCT | 330 | 330 | 330 | 260 | 260 | 260 |
| A4L | 14 | Namewaminikan JCT | Namewaminikan CGS | 580 | 690 | 710 | 500 | 630 | 660 |
| A4L | 15 | A4L STR 217 JCT | A.P. Nipigon JCT | 390 | 390 | 390 | 310 | 310 | 310 |
| A5A | 1 | Alexander SS | Minnova JCT | 580 | 580 | 580 | 430 | 430 | 430 |
| A5A | 1 | Alexander SS | Minnova JCT | 580 | 580 | 580 | 430 | 430 | 430 |
| A5A | 2 | Minnova JCT | Schreiber JCT | 580 | 580 | 580 | 430 | 430 | 430 |
| A5A | 3 | Schreiber JCT | Aguasabon SS | 580 | 580 | 580 | 430 | 430 | 430 |
| A5A | 4 | Schreiber JCT | Schreiber Winnipg DS | 330 | 330 | 330 | 260 | 260 | 260 |
| A5A | 6 | Minnova JCT | Minnova JCT | 430 | 430 | 430 | 340 | 340 | 340 |
| A6P | 1 | Alexander SS | Reserve JCT | 640 | 680 | 680 | 520 | 520 | 520 |
| A6P | 2 | Reserve JCT | Port Arthur TS #1 | 630 | 630 | 630 | 540 | 540 | 540 |
| A7L | 1 | Alexander SS | Reserve JCT | 430 | 430 | 440 | 340 | 340 | 340 |
| A7L | 2 | Reserve JCT | Lakehead TS | 430 | 430 | 430 | 340 | 340 | 340 |
| A8L | 1 | Alexander SS | Lakehead TS | 540 | 540 | 540 | 420 | 420 | 420 |
| B15 | 1 | Thunder Bay SS | Abitibi JCT | 1300 | 1580 | 1780 | 1110 | 1440 | 1660 |
| B15 | 2 | Abitibi JCT | James Street JCT | 1000 | 1090 | 1140 | 850 | 970 | 1030 |
| B15 | 3 | James Street JCT | St.Paul JCT | 1000 | 1090 | 1140 | 850 | 970 | 1030 |
| B15 | 4 | St.Paul JCT | Walsh Street JCT | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |

| Circuit | Section | From | To | Winter Ratings (A) | | | Summer Ratings (A) | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Cont | LTE | STE | Cont | LTE | STE |
| B15 | 5 | Walsh Street JCT | Birch TS | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| B15 | 6 | James Street JCT | ResFP Thundr Bay CTS | 1000 | 1200 | 1430 | 850 | 1100 | 1350 |
| B15 | 7 | St.Paul JCT | ResFP Kraft CTS | 720 | 870 | 940 | 620 | 790 | 870 |
| B15 | 8 | Walsh Street JCT | Fort William TS | 1000 | 1090 | 1140 | 850 | 960 | 1020 |
| B3E | 1 | Blind River TS | Elliot Lake JCT | 580 | 700 | 720 | 500 | 640 | 670 |
| B3E | 2 | Elliot Lake JCT | Elliot Lake TS | 580 | 700 | 720 | 500 | 640 | 670 |
| B5 | 1 | Thunder Bay SS | Abitibi JCT | 1300 | 1580 | 1780 | 1110 | 1440 | 1660 |
| B5 | 2 | Abitibi JCT | James Street JCT | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| B5 | 3 | James Street JCT | St.Paul JCT | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| B5 | 4 | St.Paul JCT | Walsh Street JCT | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| B5 | 5 | Walsh Street JCT | Birch TS | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| B5 | 6 | Abitibi JCT | Erco JCT | 720 | 870 | 950 | 620 | 790 | 880 |
| B5 | 7 | Erco JCT | Q5B STR A6 JCT | 720 | 870 | 950 | 620 | 790 | 880 |
| B5 | 8 | James Street JCT | ResFP Thundr Bay CTS | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| B5 | 9 | St.Paul JCT | ResFP Kraft CTS | 720 | 810 | 840 | 620 | 720 | 760 |
| B5 | 10 | Walsh Street JCT | Fort William TS | 1000 | 1000 | 1000 | 850 | 850 | 850 |
| B6M | 1 | Birch TS | Murillo JCT | 590 | 590 | 590 | 440 | 440 | 450 |
| B6M | 2 | Stanley JCT | Shabaqua JCT | 580 | 580 | 580 | 430 | 430 | 430 |
| B6M | 3 | Shabaqua JCT | Shebandowan JCT | 610 | 610 | 610 | 470 | 470 | 470 |
| B6M | 4 | Shebandowan JCT | Kashabowie JCT | 600 | 600 | 600 | 460 | 460 | 460 |
| B6M | 5 | Kashabowie JCT | Sapawe JCT | 580 | 580 | 580 | 430 | 430 | 430 |
| B6M | 6 | Caland Ore JCT | Moose Lake TS | 720 | 820 | 850 | 620 | 740 | 770 |
| B6M | 7 | Shabaqua JCT | Shabaqua DS | 430 | 510 | 570 | 370 | 470 | 530 |
| B6M | 12 | Murillo JCT | Stanley JCT | 580 | 580 | 580 | 430 | 430 | 430 |
| B6M | 15 | Sapawe JCT | Caland Ore JCT | 720 | 820 | 850 | 620 | 740 | 770 |
| B6M | 16 | Sapawe JCT | Sapawe DS | 580 | 690 | 790 | 500 | 630 | 740 |
| B6M | 17 | Murillo JCT | Murillo DS | 330 | 330 | 330 | 260 | 260 | 260 |
| B9 | 1 | Thunder Bay SS | Birch TS | 1270 | 1530 | 1730 | 1090 | 1390 | 1600 |
| C1A | 1 | Cameron Falls GS | Alexander SS | 720 | 870 | 920 | 620 | 790 | 840 |
| C1A | 2 | Alexander SS | Alexander GS | 720 | 870 | 920 | 620 | 790 | 840 |
| C1A | 3 | Alexander SS | Alexander SS | 540 | 540 | 540 | 420 | 420 | 420 |
| C2M | 1 | Pickle Lake SS | C2M T#NB1 JCT | 480 | 480 | 480 | 380 | 380 | 380 |
| C2M | 2 | C2M T#NB1 JCT | Placer JCT | 430 | 430 | 430 | 340 | 340 | 340 |
| C2M | 3 | Placer JCT | Placer JCT | 280 | 280 | 280 | 230 | 230 | 230 |
| C2M | 4 | Placer JCT | Crow River DS | 280 | 280 | 280 | 230 | 230 | 230 |
| C2M | 5 | C2M T#NB1 JCT | Musselwhite CSS | 430 | 430 | 430 | 340 | 340 | 340 |
| C2M | 6 | Placer JCT | Crow River DS | 280 | 280 | 280 | 230 | 230 | 230 |
| C3A | 1 | Cameron Falls GS | Alexander SS | 720 | 870 | 920 | 620 | 790 | 840 |
| C3A | 2 | Alexander SS | Alexander GS | 720 | 870 | 920 | 620 | 790 | 840 |
| C3A | 3 | Alexander SS | Alexander SS | 720 | 870 | 920 | 620 | 790 | 840 |
| C3W | 1 | Pickle Lake CTS | Pickle Lake SS | 730 | 730 | 730 | 550 | 550 | 550 |
| D26A | 1 | Dryden TS | Mackenzie TS | 1020 | 1020 | 1020 | 880 | 880 | 880 |

| Circuit | Section | From | To | Winter Ratings (A) | | | Summer Ratings (A) | | |
|---------|---------|------|-----|------|-----|-----|------|-----|-----|
| | | | | Cont | LTE | STE | Cont | LTE | STE |
| D26A | 1 | Dryden TS | Dinorwic JCT | 1020 | 1020 | 1020 | 880 | 880 | 880 |
| D26A | 2 | Dinorwic JCT | Mackenzie TS | 1020 | 1020 | 1020 | 880 | 880 | 880 |
| D26A | 4 | Dinorwic JCT | Dinorwic JCT | 1020 | 1020 | 1020 | 880 | 880 | 880 |
| D5D | 1 | Dryden TS | Dryden JCT B | 720 | 870 | 1020 | 620 | 790 | 960 |
| D5D | 2 | Dryden JCT B | Domtar Dryden CTS | 670 | 670 | 670 | 550 | 550 | 550 |
| D5D | 3 | Dryden JCT B | Dryden JCT B | 670 | 670 | 670 | 550 | 550 | 550 |
| E1C | 1 | Ear Falls TS | Selco JCT | 280 | 280 | 280 | 230 | 230 | 230 |
| E1C | 2 | Selco JCT | Slate Falls JCT | 280 | 280 | 280 | 230 | 230 | 230 |
| E1C | 3 | Etruscan JCT | Placer JCT | 280 | 280 | 280 | 230 | 230 | 230 |
| E1C | 3 | Etruscan JCT | E1C T#NA1 JCT | 280 | 280 | 280 | 230 | 230 | 230 |
| E1C | 5 | Etruscan JCT | Etruscan Entrprs CTS | 280 | 280 | 280 | 230 | 230 | 230 |
| E1C | 8 | Golden Patricia JCT | Etruscan JCT | 280 | 280 | 280 | 230 | 230 | 230 |
| E1C | 8 | Golden Patricia JCT | Etruscan JCT | 280 | 280 | 280 | 230 | 230 | 230 |
| E1C | 11 | Slate Falls JCT | Golden Patricia JCT | 280 | 280 | 280 | 230 | 230 | 230 |
| E1C | 11 | Slate Falls JCT | Golden Patricia JCT | 280 | 280 | 280 | 230 | 230 | 230 |
| E1C | 12 | Slate Falls JCT | Slate Falls DS | 280 | 280 | 280 | 230 | 230 | 230 |
| E1C | 13 | Placer JCT | Crow River DS | 280 | 280 | 280 | 230 | 230 | 230 |
| E1C | 14 | Placer JCT | Placer JCT | 280 | 280 | 280 | 230 | 230 | 230 |
| E1C | 15 | Placer JCT | Crow River DS | 280 | 280 | 280 | 230 | 230 | 230 |
| E1C | 16 | Placer JCT | Musselwhite CSS | 430 | 430 | 430 | 340 | 340 | 340 |
| E1C | 17 | Golden Patricia JCT | Golden Patricia JCT | 280 | 280 | 280 | 230 | 230 | 230 |
| E1C | 18 | E1C T#NA1 JCT | Placer JCT | 280 | 280 | 280 | 230 | 230 | 230 |
| E1C | 19 | E1C T#NA1 JCT | Pickle Lake SS | 480 | 480 | 480 | 380 | 380 | 380 |
| E2R | 1 | Ear Falls TS | Pakwash JCT | 540 | 540 | 540 | 420 | 420 | 420 |
| E2R | 2 | Pakwash JCT | Balmer JCT | 540 | 540 | 540 | 420 | 420 | 420 |
| E2R | 4 | Balmer JCT | Red Lake TS | 540 | 540 | 540 | 420 | 420 | 420 |
| E2R | 4 | Balmer JCT | Red Lake JCT | 540 | 540 | 540 | 420 | 420 | 420 |
| E2R | 6 | Red Lake JCT | Red Lake TS | 540 | 540 | 540 | 420 | 420 | 420 |
| E2R | 7 | Red Lake JCT | Red Lake CSS | 540 | 540 | 540 | 420 | 420 | 420 |
| E4D | 1 | Ear Falls TS | Scout Lake JCT | 610 | 610 | 610 | 470 | 470 | 470 |
| E4D | 2 | Scout Lake JCT | Dryden TS | 610 | 610 | 610 | 470 | 470 | 470 |
| E4D | 3 | Scout Lake JCT | Perrault Falls DS | 280 | 280 | 280 | 230 | 230 | 230 |
| F1B | 1 | Fort Frances TS | Fort Frances JCT | 550 | 550 | 550 | 460 | 460 | 460 |
| F1B | 2 | Burleigh JCT | Burleigh DS | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| F1B | 3 | Fort Frances TS | Fort Frances MTS | 430 | 430 | 430 | 340 | 340 | 340 |
| F1B | 4 | Fort Frances JCT | Burleigh JCT | 550 | 550 | 550 | 460 | 460 | 460 |
| F1B | 5 | Burleigh JCT | Hwy #11 JCT | 600 | 600 | 600 | 280 | 280 | 280 |
| F25A | 1 | Fort Frances TS | Mackenzie TS | 1020 | 1020 | 1020 | 880 | 880 | 880 |
| F2B | 1 | Fort Frances TS | H2O Pwr FtFrnces CGS | 720 | 830 | 860 | 620 | 740 | 780 |
| F3M | 1 | Fort Frances TS | H2O Pwr FtFrnces CGS | 920 | 920 | 920 | 750 | 750 | 750 |
| F3M | 2 | H2O Pwr FtFrnces CGS | Int'l Bdy Minn JCT | 850 | 920 | 920 | 730 | 750 | 750 |
| K21W | 1 | Kenora TS | IPB Manitoba 230 JCT | 1020 | 1020 | 1020 | 880 | 880 | 880 |

| Circuit | Section | From | To | Winter Ratings (A) | | | Summer Ratings (A) | | |
|---------|---------|------|-----|-------|------|------|------|------|------|
| | | | | Cont | LTE | STE | Cont | LTE | STE |
| K22W | 1 | Kenora TS | IPB Manitoba 230 JCT | 1020 | 1020 | 1020 | 880 | 880 | 880 |
| K23D | 1 | Kenora TS | TCPL Vermill Bay JCT | 1020 | 1020 | 1020 | 880 | 880 | 880 |
| K23D | 2 | TCPL Vermill Bay JCT | Dryden TS | 1020 | 1020 | 1020 | 880 | 880 | 880 |
| K23D | 3 | TCPL Vermill Bay JCT | TCPL Vermill Bay CTS | 1020 | 1020 | 1020 | 880 | 880 | 880 |
| K24F | 1 | Kenora TS | Rainy River Gold JCT | 1020 | 1170 | 1250 | 880 | 1060 | 1140 |
| K24F | 2 | Rainy River Gold JCT | Fort Frances TS | 1020 | 1170 | 1250 | 880 | 1060 | 1140 |
| K24F | 3 | Rainy River Gold JCT | Rainy River Gold CSS | 1020 | 1170 | 1250 | 880 | 1060 | 1140 |
| K2M | 1 | Rabbit Lake SS | Norman JCT | 710 | 710 | 710 | 600 | 600 | 610 |
| K3D | 1 | Rabbit Lake SS | K3D-10 SW JCT | 610 | 610 | 610 | 470 | 470 | 470 |
| K3D | 2 | K3D-10 SW JCT | Vermilion Bay JCT | 610 | 610 | 610 | 470 | 470 | 470 |
| K3D | 3 | Vermilion Bay JCT | Eton JCT | 610 | 610 | 610 | 470 | 470 | 470 |
| K3D | 4 | Vermilion Bay JCT | Vermilion Bay DS | 430 | 510 | 570 | 370 | 470 | 530 |
| K3D | 5 | Dryden TS | Sam Lake DS | 540 | 540 | 540 | 420 | 420 | 420 |
| K3D | 6 | Eton JCT | Dryden TS | 610 | 610 | 610 | 470 | 470 | 470 |
| K3D | 7 | Eton JCT | Eton DS | 430 | 510 | 570 | 370 | 470 | 530 |
| K4W | 1 | Rabbit Lake SS | Minaki JCT | 580 | 580 | 580 | 430 | 430 | 430 |
| K4W | 2 | Minaki JCT | Whitedog Falls SS | 720 | 790 | 810 | 620 | 700 | 720 |
| K4W | 3 | Minaki JCT | Minaki DS | 580 | 580 | 580 | 430 | 430 | 430 |
| K4W | 4 | Minaki JCT | Minaki DS | 580 | 580 | 580 | 430 | 430 | 430 |
| K5W | 1 | Rabbit Lake SS | Minaki JCT | 580 | 580 | 580 | 430 | 430 | 430 |
| K5W | 3 | Minaki JCT | Whitedog Falls SS | 720 | 720 | 720 | 610 | 610 | 610 |
| K6F | 1 | Rabbit Lake SS | Margach JCT | 650 | 650 | 650 | 530 | 530 | 530 |
| K6F | 2 | Margach JCT | Sioux Narrows JCT | 580 | 580 | 580 | 430 | 430 | 430 |
| K6F | 3 | K6F-10 SW JCT | Nestor Falls JCT | 610 | 610 | 610 | 470 | 470 | 470 |
| K6F | 4 | Nestor Falls JCT | Ainsworth JCT | 610 | 610 | 610 | 470 | 470 | 470 |
| K6F | 5 | Sioux Narrows JCT | Sioux Narrows DS | 720 | 870 | 1020 | 620 | 790 | 960 |
| K6F | 6 | Nestor Falls JCT | Nestor Falls DS | 370 | 440 | 490 | 320 | 400 | 460 |
| K6F | 7 | Sioux Narrows JCT | K6F-10 SW JCT | 650 | 650 | 650 | 530 | 530 | 530 |
| K6F | 8 | Ainsworth JCT | Fort Frances JCT | 610 | 610 | 610 | 470 | 470 | 470 |
| K6F | 10 | Margach JCT | Margach DS | 370 | 440 | 490 | 320 | 400 | 460 |
| K6F | 11 | Margach JCT | Margach DS | 370 | 440 | 490 | 320 | 400 | 460 |
| K6F | 12 | Ainsworth JCT | Barwick JCT | 430 | 450 | 450 | 370 | 390 | 400 |
| K6F | 13 | Fort Frances JCT | Fort Frances TS | 610 | 610 | 610 | 470 | 470 | 470 |
| K6F | 14 | Fort Frances JCT | Fort Frances JCT | 610 | 610 | 610 | 470 | 470 | 470 |
| K6F | 15 | Barwick JCT | Ainsworth Str #4 JCT | 430 | 450 | 450 | 370 | 390 | 400 |
| K6F | 16 | Barwick JCT | Barwick TS | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| K6F | 17 | Barwick JCT | Barwick TS | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| K7K | 1 | Kenora TS | Kenora TS | 720 | 870 | 1020 | 620 | 790 | 960 |
| K7K | 2 | Kenora TS | Rabbit Lake SS | 720 | 870 | 970 | 620 | 790 | 910 |
| K7K | 3 | Kenora TS | Weyerhaeuser Ken CTS | 360 | 360 | 360 | 280 | 280 | 280 |
| L3P | 1 | Lakehead TS | Port Arthur TS #1 | 840 | 1000 | 1200 | 720 | 920 | 1130 |
| L4P | 1 | Lakehead TS | Port Arthur TS #1 | 720 | 870 | 1020 | 620 | 790 | 960 |

| Circuit | Section | From | To | Winter Ratings (A) | | | Summer Ratings (A) | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Cont | LTE | STE | Cont | LTE | STE |
| M1S | 1 | Moose Lake TS | Valerie Falls JCT | 450 | 450 | 450 | 320 | 320 | 320 |
| M1S | 2 | Mill Creek JCT | H2O Pwr SturgFls CGS | 540 | 540 | 540 | 450 | 450 | 460 |
| M1S | 4 | Mill Creek JCT | H2O Pwr Calm Lk CGS | 340 | 340 | 340 | 280 | 280 | 280 |
| M1S | 6 | Valerie Falls JCT | Mill Creek JCT | 450 | 450 | 450 | 320 | 320 | 320 |
| M23L | 1 | Marathon TS | Greenwich WF CGS JCT | 1020 | 1070 | 1100 | 880 | 940 | 970 |
| M23L | 1 | Marathon TS | Greenwich WF CGS JCT | 1020 | 1070 | 1100 | 880 | 940 | 970 |
| M23L | 2 | Greenwich WF CGS JCT | Lakehead TS | 1020 | 1230 | 1510 | 880 | 1120 | 1430 |
| M23L | 2 | Greenwich WF CGS JCT | Lakehead TS | 1020 | 1230 | 1510 | 880 | 1120 | 1430 |
| M23L | 4 | Greenwich WF CGS JCT | Greenwich LakeWF CSS | 1020 | 1030 | 1040 | 880 | 890 | 900 |
| M24L | 1 | Marathon TS | Greenwich WF CGS JCT | 1020 | 1140 | 1210 | 880 | 1020 | 1090 |
| M24L | 1 | Marathon TS | Greenwich WF CGS JCT | 1020 | 1140 | 1210 | 880 | 1020 | 1090 |
| M24L | 2 | Greenwich WF CGS JCT | Lakehead TS | 1020 | 1230 | 1510 | 880 | 1120 | 1430 |
| M24L | 2 | Greenwich WF CGS JCT | Lakehead TS | 1020 | 1230 | 1510 | 880 | 1120 | 1430 |
| M24L | 4 | Greenwich WF CGS JCT | Greenwich LakeWF CSS | 1020 | 1030 | 1040 | 880 | 890 | 900 |
| M2D | 1 | Ignace JCT | Dryden TS | 540 | 540 | 540 | 420 | 420 | 420 |
| M2D | 1 | Ignace JCT | Dryden TS | 540 | 540 | 540 | 420 | 420 | 420 |
| M2D | 2 | Moose Lake TS | Ignace JCT | 670 | 670 | 670 | 550 | 550 | 550 |
| M2D | 4 | Dryden TS | Dryden TS | 670 | 670 | 670 | 550 | 550 | 550 |
| M2D | 5 | Dryden TS | Dryden JCT B | 670 | 670 | 670 | 550 | 550 | 550 |
| M2W | 1 | Marathon TS | Pic JCT | 720 | 870 | 1020 | 620 | 790 | 960 |
| M2W | 1 | Marathon TS | Pic JCT | 720 | 870 | 1020 | 620 | 790 | 960 |
| M2W | 2 | Pic JCT | Manitouwadge JCT | 430 | 450 | 460 | 350 | 350 | 350 |
| M2W | 4 | Manitouwadge JCT | Willroy JCT | 580 | 690 | 790 | 500 | 630 | 740 |
| M2W | 6 | Manitouwadge JCT | Manitouwadge JCT B | 580 | 690 | 720 | 500 | 630 | 660 |
| M2W | 8 | Marathon TS | Black River JCT | 430 | 510 | 570 | 370 | 470 | 530 |
| M2W | 8 | Marathon TS | Black River JCT | 430 | 510 | 570 | 370 | 470 | 530 |
| M2W | 9 | Williams Mine JCT | Hemlo Mine JCT | 330 | 330 | 330 | 230 | 230 | 240 |
| M2W | 10 | Hemlo Mine JCT | Animki JCT | 430 | 510 | 570 | 370 | 470 | 530 |
| M2W | 10 | Hemlo Mine JCT | Animki JCT | 430 | 510 | 570 | 370 | 470 | 530 |
| M2W | 15 | Marathon TS | Pic DS | 370 | 440 | 490 | 320 | 400 | 460 |
| M2W | 16 | Black River JCT | Umbata Falls JCT | 430 | 510 | 570 | 370 | 470 | 530 |
| M2W | 16 | Black River JCT | Umbata Falls JCT | 430 | 510 | 570 | 370 | 470 | 530 |
| M2W | 22 | Manitouwadge JCT B | Manitouwadge DS #1 | 370 | 440 | 470 | 320 | 400 | 440 |
| M2W | 25 | Umbata Falls JCT | Williams Mine JCT | 330 | 330 | 330 | 230 | 230 | 240 |
| M2W | 25 | Umbata Falls JCT | Williams Mine JCT | 330 | 330 | 330 | 230 | 230 | 240 |
| M2W | 26 | Manitouwadge JCT B | Manitouwadge TS | 580 | 690 | 790 | 500 | 630 | 740 |
| M2W | 27 | Animki JCT | White River DS | 430 | 510 | 570 | 370 | 470 | 530 |
| M2W | 27 | Animki JCT | White River DS | 430 | 510 | 570 | 370 | 470 | 530 |
| M37L | 1 | Lakehead TS | M37L_M38L T#A001 JCT | 1300 | 1580 | 1780 | 1120 | 1440 | 1650 |
| M37L | 3 | M37L_M38L T#C279 JCT | Marathon TS | 1300 | 1580 | 1780 | 1120 | 1440 | 1650 |
| M38L | 1 | Lakehead TS | M37L_M38L T#A001 JCT | 1300 | 1580 | 1780 | 1120 | 1440 | 1650 |
| M38L | 3 | M37L_M38L T#C279 JCT | Marathon TS | 1300 | 1580 | 1780 | 1120 | 1440 | 1650 |

| Circuit | Section | From | To | Winter Ratings (A) | | | Summer Ratings (A) | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Cont | LTE | STE | Cont | LTE | STE |
| N93A | 1 | Atikokan TGS | Marmion Lake JCT | 1020 | 1230 | 1510 | 880 | 1120 | 1430 |
| N93A | 2 | Marmion Lake JCT | Mackenzie TS | 1300 | 1580 | 2030 | 1120 | 1440 | 1920 |
| P1P | 1 | Port Arthur TS #1 | Port Arthur JCT | 430 | 510 | 570 | 370 | 470 | 530 |
| P1T | 1 | Port Arthur TS #1 | TBPI Thunder Bay JCT | 580 | 690 | 710 | 500 | 630 | 660 |
| P1T | 2 | TBPI Thunder Bay JCT | TBPI Thunder Bay CTS | 430 | 510 | 570 | 370 | 470 | 530 |
| P1T | 3 | TBPI Thunder Bay JCT | TBPI Thunder Bay JCT | 580 | 690 | 710 | 500 | 630 | 660 |
| P1T | 4 | TBPI Thunder Bay JCT | TBPI Thunder Bay CTS | 430 | 510 | 570 | 370 | 470 | 530 |
| P21G | 1 | Mississagi TS | P21G POLE 261 JCT | 1020 | 1230 | 1510 | 880 | 1120 | 1430 |
| P21G | 2 | P21G POLE 261 JCT | Third Line TS | 1128 | 0 | 1200 | 963 | 0 | 1068 |
| P22G | 1 | Mississagi TS | Echo River TS | 1128 | 0 | 1200 | 963 | 0 | 1068 |
| P22G | 2 | Echo River TS | Third Line TS | 1128 | 0 | 1200 | 963 | 0 | 1068 |
| 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 |
| P3B | 1 | Port Arthur TS #1 | Birch TS | 720 | 830 | 860 | 620 | 740 | 780 |
| P5M | 1 | Port Arthur TS #1 | Conmee JCT | 580 | 610 | 620 | 500 | 530 | 540 |
| P5M | 4 | P5M STR 603 JCT | P5M STR 608 JCT | 580 | 580 | 580 | 430 | 430 | 430 |
| P5M | 6 | P5M STR 621 JCT | P5M STR 626 JCT | 580 | 580 | 580 | 430 | 430 | 430 |
| P7B | 1 | Port Arthur TS #1 | P7B STR 320 JCT | 840 | 920 | 960 | 720 | 830 | 860 |
| P7B | 2 | P7B STR 320 JCT | Birch TS | 720 | 870 | 940 | 620 | 790 | 870 |
| Q4B | 1 | Thunder Bay SS | Abitibi JCT | 1300 | 1580 | 1780 | 1110 | 1440 | 1660 |
| Q4B | 2 | Abitibi JCT | James Street JCT | 1000 | 1090 | 1140 | 850 | 970 | 1030 |
| Q4B | 3 | James Street JCT | St.Paul JCT | 1000 | 1090 | 1140 | 850 | 970 | 1030 |
| Q4B | 4 | St.Paul JCT | Walsh Street JCT | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| Q4B | 5 | Walsh Street JCT | Birch TS | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| Q4B | 6 | James Street JCT | ResFP Thundr Bay CTS | 1000 | 1200 | 1430 | 850 | 1100 | 1350 |
| Q4B | 7 | St.Paul JCT | ResFP Kraft CTS | 720 | 870 | 940 | 620 | 790 | 870 |
| Q4B | 8 | Walsh Street JCT | Fort William TS | 1000 | 1090 | 1140 | 850 | 960 | 1020 |
| Q5B | 1 | Thunder Bay SS | Abitibi JCT | 1300 | 1580 | 1780 | 1110 | 1440 | 1660 |
| Q5B | 2 | Abitibi JCT | James Street JCT | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| Q5B | 3 | James Street JCT | St.Paul JCT | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| Q5B | 4 | St.Paul JCT | Walsh Street JCT | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| Q5B | 5 | Walsh Street JCT | Birch TS | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| Q5B | 6 | Abitibi JCT | Erco JCT | 720 | 870 | 950 | 620 | 790 | 880 |
| Q5B | 7 | Erco JCT | Q5B STR A6 JCT | 720 | 870 | 950 | 620 | 790 | 880 |
| Q5B | 8 | James Street JCT | ResFP Thundr Bay CTS | 1000 | 1200 | 1490 | 850 | 1100 | 1410 |
| Q5B | 9 | St.Paul JCT | ResFP Kraft CTS | 720 | 810 | 840 | 620 | 720 | 760 |
| Q5B | 10 | Walsh Street JCT | Fort William TS | 1000 | 1000 | 1000 | 850 | 850 | 850 |
| R1LB | 1 | Pine Portage SS | Lakehead TS | 410 | 410 | 410 | 330 | 330 | 330 |

| Circuit | Section | From | To | Winter Ratings (A) | | | Summer Ratings (A) | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Cont | LTE | STE | Cont | LTE | STE |
| R1LB | 2 | Lakehead TS | Birch TS | 720 | 860 | 910 | 620 | 790 | 840 |
| R2LB | 1 | Pine Portage SS | Lakehead TS | 540 | 540 | 540 | 420 | 420 | 420 |
| R2LB | 2 | Lakehead TS | Birch TS | 720 | 870 | 920 | 620 | 790 | 840 |
| R9A | 1 | Pine Portage SS | Alexander SS | 540 | 540 | 540 | 420 | 420 | 420 |
| R9A | 2 | Alexander SS | Alexander GS | 430 | 430 | 430 | 340 | 340 | 340 |
| R9A | 3 | Alexander SS | Alexander SS | 540 | 540 | 540 | 420 | 420 | 420 |
| S1C | 1 | Conmee JCT | Lac Des Iles JCT | 560 | 560 | 560 | 400 | 400 | 400 |
| S1C | 2 | Lac Des Iles JCT | Silver Falls GS | 560 | 560 | 560 | 400 | 400 | 400 |
| S1C | 6 | Lac Des Iles JCT | Lac Des Iles Min CSS | 430 | 450 | 450 | 370 | 390 | 400 |
| T1M | 1 | Terrace Bay SS | Angler Switch JCT | 600 | 600 | 600 | 460 | 460 | 460 |
| T1M | 2 | Angler Switch JCT | Pic JCT | 600 | 600 | 600 | 460 | 460 | 460 |
| T1M | 3 | Pic JCT | Marathon TS | 720 | 870 | 1020 | 620 | 790 | 960 |
| T1M | 3 | Pic JCT | Marathon TS | 720 | 870 | 1020 | 620 | 790 | 960 |
| T1M | 4 | Pic JCT | Marathon DS JCT | 430 | 490 | 490 | 370 | 440 | 450 |
| T1M | 5 | Marathon DS JCT | Marathon DS | 430 | 490 | 490 | 370 | 440 | 450 |
| W21M | 1 | Wawa TS | Marathon TS | 1020 | 1020 | 1020 | 880 | 880 | 880 |
| W21M | 1 | Wawa TS | Marathon TS | 1020 | 1020 | 1020 | 880 | 880 | 880 |
| W22M | 1 | Wawa TS | Marathon TS | 1020 | 1140 | 1200 | 880 | 1020 | 1080 |
| W22M | 1 | Wawa TS | Marathon TS | 1020 | 1140 | 1200 | 880 | 1020 | 1080 |
| W35M | 1 | Marathon TS | W35M_W36M T#D001 JCT | 1300 | 1580 | 1780 | 1120 | 1440 | 1650 |
| W35M | 4 | W35M T#F235 JCT | Wawa TS | 1300 | 1580 | 1780 | 1120 | 1440 | 1650 |
| W36M | 1 | Marathon TS | W35M_W36M T#D001 JCT | 1300 | 1580 | 1780 | 1120 | 1440 | 1650 |
| W36M | 4 | W36M T#F233 JCT | Wawa TS | 1300 | 1580 | 1780 | 1120 | 1440 | 1650 |
| W3C | 1 | Whitedog Falls SS | Caribou Falls GS | 670 | 670 | 670 | 550 | 550 | 550 |

## C.2.2 Special Protection Systems

Table 6 below shows the available special protection systems in the study region.

**Table 5 | Relevant Special Protection Systems**

| Facility | Description |
|---|---|
| NW-SPS | The Northwest SPS is used to prevent instability in the West system, prevent low and high voltage in Wawa area, and prevent high voltages in Algoma Area. Following the loss of East-West 230kV tie between Wawa and Mississagi, Algoma and Mississagi, Algoma and Sudbury with flows west, it rejects load in Lakehead area, Great Lakes Power and/or Algoma and/or trip capacitor at Algoma. |
| NW-SPS2 | Northwest SPS 2 has the capability of cross-tripping multiple 115 kV circuits. The scheme initiates cross-tripping based on single or double circuit contingencies on the 230 kV lines. |

**---- End of Section ---**

# C.3 Credible Planning Events and Criteria

## C.3.1 Studied Contingencies

Table 7 below shows the types of contingencies assessed and how they map to applicable standards. The table also specifies the amount of load rejection/curtailment allowed as per ORTAC.

**Table 6 | Types of Contingencies Assessed**

| Pre-contingency | Contingency[2] | Type | Mapping to TPL/Directory 1 Event | Rating[3] | 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 |
| 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-1 | P3 | LTE | 150 MW by-configuration; >0 MW lost by curtailment[4]; Total 150 MW |
| | Double | N-2 | N/A | STE, reduced to LTE | >150 MW lost by curtailment[3] ; 600 MW Total |
| 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 |

---

[2] 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.

[3] 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.

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

The tables below show the single, common tower, and breaker failure contingencies. Note that:

- Breaker failures and transformer failures 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 very similar to the N-1 contingencies documented in Table 8 but may be slightly different in some cases to reflect the fact that outages are the removal of a single element rather than all elements in a single zone of protection.

**Table 7 | Studied N-1 Contingencies**

| | | | Contingencies | | | |
|---|---|---|---|---|---|---|
| 15M1 | C2A | Fort Frances T1 | Lac Des Iles Mine T5 | Murillo T3 | Sachigo TS T1 | W2 |
| 29M1 | C2M | Fort Frances T2 | Lakehead R1 | Muskrat TS T1 | Sachigo TS T2 | W21M |
| 56M1 | C3A | Fort William EG | Lakehead SC11 | Muskrat TS T2 | Sam Lake T1 | W22M |
| 57M1 | C3W | Fort William T5 | Lakehead SC21 | Mussel White T1 | Sam Lake T2 | W35M |
| A1B | Calm Lake T1 | Fort William T6 | Lakehead T7 | Mussel White T2 | Sandy Lake T1 | W36M |
| A21L | Cameron Falls T1 | Geco T1 | Lakehead T8 | N93A | Sandy Lake T2 | W3C |
| A22L | Cameron Falls T2 | Greenwich T1 | Long Rapids Gen | Namewamns s T1 | Sapawe T1 | W54W |
| A23L | Cameron Falls T3 | Greenwich T2 | Longlac T2 | Nestor Falls T1 | Sapawe T2 | W8C |
| A24L | Caribou Falls T1 | Jellico T1 | Longlac T3 | Nipigon 24T1 | Schreiber T1 | WCD |
| A3M | Cat Lake T1 | K21W | Lowerwhite T1 | Nipigon GS T1 | Shabaqua T1 | WCJ |
| A4L | Clearwater Bay T1 | K22W | M1S | Norman 20T1 | Silver Falls T1 | WDE |
| A5A | Crow River T1 | K23D | M23L | North Caribou Lake T1 | Sioux Narrows T1 | WEF |
| A6P | Crow River T2 | K24F | M24L | North Caribou Lake T2 | Sioux Narrows T2 | WEG |
| A7L | D26A | K2M | M2D | P1T | Slate Falls T1 | WJK |
| A8L | D5D | K3D | M2W | P3B | South Bay T1 | WKM |
| Agimak T1 | Deer Lake TS T1 | K4W | M37L | P5M | Spirit Lake T1 | WPQ |
| Agimak T2 | Deer Lake TS T2 | K5W | M38L | P7B | Spirit Lake T2 | WQR |
| Aguasabo n T1 | Dryden Gen EG | K6F | M3E | Perrault Falls T1 | Sturgeon Falls T1 | WRS |
| Ainsworth T1 | Dryden T22 | K7K | Mackenzie T3 | Pic T1 | T1M | WRT |

# Contingencies

| | | | | | | |
|---|---|---|---|---|---|---|
| Alexander T1 | Dryden T23 | Kakabeka G1 | Manitou Falls T1 | Pic T2 | Tbaybowater T04 | WTU |
| Alexander T2 | Dryden T4 | Kakabeka G2 | Manitou Falls T2 | Pikangi TS T1 | Tbaybowater T1 | WTZ |
| Alexander T3 | Dryden T5 | Kakabeka G3 | Manitouwa DS T1 | Pikangi TS T2 | Tbaybowater T2 | WVY |
| Alexander T4 | E1C | Kakabeka G4 | Manitouwa T1 | Pine Portage T1 | Tbaybowater T3 | WZV |
| Atikokan T1 | E2R | Keewatin T1 | Marathon DS 2735T1 | Pine Portage T2 | Tbaybowater T6 | WZW |
| B6M | E4D | Keeway TS T1 | Marathon R11 | Poplar Lake T1 | Tbaybowater TA | Wapekeka TS T1 |
| BOWATR T26903 | Ear Falls T1 | Keeway TS T2 | Marathon R12 | Poplar Lake T2 | Tbaybowater TB | Wapekeka TS T2 |
| Balmer T1 | Ear Falls T2 | Kenora Abitibi AT1 | Marathon R3 | Port Arthur T1 | Tbaybowater TC | Watay TS T1 |
| Balmer T2 | Ear Falls T5 | Kenora DS T1 | Marathon R4 | Port Arthur T2 | Tbaybowater TD | Wawakape TS T1 |
| Barwick T1 | Esker T1 | Kenora DS T2 | Marathon SC21 | Q4B | Tbaybowater TJ | Wawakape TS T2 |
| Barwick T2 | Esker T2 | Kenora MS T1 | Marathon SC29 | Q5B | Tbaybowater TK | Wawakape TS T3 |
| Beardmore T1 | Eton T1 | Kenora MS T2 | Marathon T11 | Q8B | Tcplvermil T1 | Wawatay T1 |
| Beardmore T2 | Eton T2 | Kenora MS T4 | Marathon T12 | Q9B | Thunderbay LT2 | Weyerhaeuser Dryden T1 |
| Bearskin TS T1 | F1B | Kenora TS T1 | Margach T1 | R1LB | Thunderbay LT3 | Weyerhaeuser Dryden T2 |
| Bearskin TS T2 | F25A | Kimberclark T3 | Margach T2 | R2LB | Thunderbay T2 | Weyerhaeuser Dryden T3 |
| Birch SC11 | F2B | Kimberclark T4 | Mattabi T1 | R9A | Thunderbay T3 | Weyerhauser T1 |
| Birch T2 | F3M | Kingfisher TS T1 | Mattabi T2 | Rainy River T1 | Twin Falls Gen | White River T1 |
| Birch T3 | Fort Frances MS T1 | L3P | Minaki T1 | Rainy River T2 | UB3B | White River T2 |
| Birch T4 | Fort Frances MS T2 | L4P | Minaki T2 | Red Lake T3 | Umbata Falls MPT1 | Whitedog Falls T1 |
| Bowater 2690 | Fort Frances R2 | Lac Des Iles Mine 1209T1 | Moose Lake T2 | Red Lake T4 | Upperwhite T1 | Williams Mine T1 |
| Bowater T1 | Fort Frances SC1 | Lac Des Iles Mine 310TRF001 | Moose Lake T3 | Redrock DS T1 | Valora T1 | Williams Mine T2 |
| Burleigh T1 | Fort Frances SC2 | Lac Des Iles Mine 310TRF002 | Murillo T1 | S1C | Valrie Falls T1 | Winston T1 |
| C1A | Fort Frances SC3 | Lac Des Iles Mine T4 | Murillo T2 | SK1 | Vermillion Bay DS T1 | |

## Table 8 | Studied N-2 Contingencies

| | | Contingencies | | | | |
|---|---|---|---|---|---|---|
| A21L+A22L | M2W+M38L | Alexander GS G3T4 | Dryden HL26 | Lakehead New L4 | Marathon L21L23 | Rabbit Lake DL2 |
| A23L+A24L | M2W+T1M | Alexander GS G4G5 | Dryden JL23 | Lakehead PL22 | Marathon L22L24 | Rabbit Lake DL6 |
| A4L+A5A | M2W+W21M | Alexander GS G4T4 | Dryden JL26 | Lakehead PL24 | Marathon PL1 | Rabbit Lake HL3 |
| A7L+R1LB | M2W+W22M | Alexander GS G5T1 | Ear Falls L1L4 | Lakehead PL37 | Marathon PL2 | Rabbit Lake HL6 |
| A8L+R2LB | M2W+W35M | Alexander HL6 | Ear Falls L3L4 | Lakehead W1L37 | Marathon W1L36 | Rabbit Lake HL7 |
| B6M+P5M | M2W+W36M | Alexander HL7 | Ear Falls W1L1 | Lakehead W1L38 | Marathon W1L38 | Rabbit Lake L2L4 |
| C1A+C2A | M37L+M38L | Alexander HL8 | Ear Falls W1L3 | Lakehead W2L21 | Marathon W2L35 | Rabbit Lake L2L7 |
| C2A+C3A | M37L+T1M | Alexander KL2 | Ebane CB3 | Lakehead W2L24 | Marathon W2L37 | Rabbit Lake L3L4 |
| C3A+R9A | M38L+T1M | Alexander KL4 | Fort Frances AK1 | Mackenzie HL21 | Moose Lake L1L2 | Terrace Bay T1M |
| D26A+F25A | P3B+R1LB | Alexander KL9 | Fort Frances AK2 | Mackenzie HL93 | Moose Lake L1L3 | Thunder Bay 30Q5B |
| F1B+F25A | P7B+R2LB | Alexander L2L7 | Fort Frances EH | Mackenzie L21L25 | Moose Lake L3L6 | Thunder Bay 30Q8B |
| K21W+K22W | Q4B+Q5B | Alexander L4L5 | Fort Frances EL3 | Mackenzie L22L93 | Moose Lake TL2 | Wawa AL21 |
| K24F+K6F | Q8B+Q9B | Alexander L5L6 | Fort Frances HL1 | Mackenzie New L2 | Moose Lake TL6 | Wawa AL22 |
| K2M+SK1 | R1LB+R2LB | Alexander L8L9 | Fort Frances JL1 | Mackenzie New L3 | Musselwhite 1210M1M | Wawa AL36 |
| K4W+K5W | W21M+W22M | Birch AL1 | Fort Frances JL6 | Mackenzie New M2 | Pine Portage L1L2 | Wawa DL1 |
| L3P+L4P | W21M+W35M | Birch AL4 | Fort Frances L3L6 | Mackenzie PL22 | Pine Portage T1L2 | Wawa DL2 |
| L3P+P7B | W21M+W36M | Birch AL5 | Kenora L21L23 | Mackenzie PL25 | Pine Portage T1L9 | Wawa HL35 |
| M23L+M24L | W22M+W35M | Birch AL8 | Kenora L21L24 | Marathon AL22 | Pine Portage T2L1 | Wawa L21L26 |
| M23L+M2W | W22M+W36M | Birch KL2 | Kenora L22L23 | Marathon AL23 | Pine Portage T2L9 | Wawa L22L23 |
| M23L+M37L | W35M+W36M | Birch KL4 | Kenora PL22 | Marathon AL36 | Port Arthur 2A6P | Wawa L35L36 |
| M23L+M38L | Aguasabon T1L1 | Birch KL6 | Kenora PL24 | Marathon AL37 | Port Arthur 2L3P | Whitedog F L3L4 |
| M23L+T1M | Aguasabon T1L5 | Birch KTL3 | Lakehead HL21 | Marathon HL21 | Port Arthur 2L4P | Whitedog F L3L5 |
| M24L+M2W | Alexander GS G1T1 | Birch L2L8 | Lakehead HL23 | Marathon HL24 | Port Arthur 2P1P | Whitedog F T1L4 |
| M24L+M37L | Alexander GS G1T2 | Birch L5L6 | Lakehead HL38 | Marathon HL35 | Port Arthur 2P1T | Whitedog F T1L5 |
| M24L+M38L | Alexander GS G2T2 | Birch TL3L1 | Lakehead L22L23 | Marathon HL38 | Port Arthur 2P3B | |
| M24L+T1M | Alexander GS G2T3 | Bowater 2660 | Lakehead New L1 | Marathon KL1 | Port Arthur 2P5M | |

| M2W+M | Alexander GS | | Lakehead | Marathon | Port Arthur |
|---|---|---|---|---|---|
| 37L | G3T3 | Dryden HL23 | New L3 | KL2 | 2P7B |

## C.3.2 Planning Criteria

The study will use the planning criteria in accordance with events and performance as detailed by:

- North American Electric Reliability Corporation ("NERC") TPL-001 "Transmission System Planning Performance Requirements" ("TPL-001"),

- Northeast Power Coordinating Council ("NPCC") Directory 1 "Design and Operate of the Bulk Power System" (where appropriate), and

- IESO Ontario Resource and Transmission Assessment Criteria ("ORTAC").

**---- End of Section ---**

## C.4 Study Result Findings

With recent and ongoing transmission reinforcement projects (East-West Tie Reinforcement, Waasigan Transmission Line Project Phase 1, and the Wataynikaneyap Transmission Project) in-service, the Northwest region will be generally adequate to support forecast growth.

Technical studies did not identify any firm supply capacity needs. Nonetheless, high growth sensitivities were studied for the Red Lake/Ear Falls/Dryden and Fort Frances subsystems. IRRP studies explored the existing limitations in these areas to identify the remaining LMC and inform future planning activities should higher growth materialize. The limiting phenomena for these subsystems are fully described in the IRRP report body.

# Appendix D – Kenora MTS Demand Profiling

## D.1 General Methodology

An hourly demand 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 developed to help determine which non-wires options may be best suited to meet regional needs.

For the Niagara IRRP, 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 load transfers, outages, or infrastructure changes). Subsequently, the historical hourly data was combined with select predictor variables to perform a multiple linear regression and model the station's hourly load profile. 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[5]); and

- Economic factors (employment data[6]).

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 While 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 31 years. Additionally, to fully assess the impact of different weather sequences against the other non-weather variables, the historical weather for each of the 31 previous years was shifted both ahead and behind up to seven days, resulting in 15 daily variations. This approach ultimately led to 465 possible hourly load forecasts for each future year being forecast. For example: 31 years of historical weather data × 15 weather sequence shifts = 465 weather scenarios for each year being forecast. June 2nd 2025 was forecast assuming the historical weather from every May 26th to June 9th period that occurred between 1991 and 2021.

Subsequently, the list of 150 forecasts were ranked in ascending order based on their median energy values. Load duration curves which illustrate this ranking can be seen in Figure 4.Figure **4 | Illustrative Example: Ranking Hourly Load Profiles by Energy**

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[5] Sourced from the Ministry of Finance and Statistics Canada
[6] Sourced from the Centre for Spatial Economics, IHS Markit Ltd., and the Conference Board of Canada

**Figure 4 | Illustrative Example: Ranking Hourly Load Profiles by Energy**

The forecast in the 3rd percentile was considered the "Extreme Peak" (extreme profile, red curve) and the forecast in the 50th percentile was chosen was the "Median Peak" (median profile, green curve). For the Northwest IRRP, the median profiles were scaled to their respective maximums from the peak demand forecast.

## D.2 Kenora MTS Demand and Energy-not-Served Profiles

The Kenora MTS hourly demand forecast can be found in the accompanying Excel spreadsheet Table D.2.

# Appendix E – Energy Efficiency

Energy efficiency is a low cost resource that offers significant benefits to individuals, businesses and the electricity system as a whole. Targeting energy efficiency in areas of the province with regional and local needs can help offset investments in new power plants and transmission lines, defer this spending to a later date and/or can compliment these investments as part of an integrated solution for the area.

To understand the scale of opportunity and associated costs for targeting energy efficiency in a local area, data and assumptions can be leveraged from provincial energy efficiency potential forecasts. In 2019, the IESO and the Ontario Energy Board completed the first integrated electricity and natural gas achievable potential study in Ontario (2019 APS)[7]. The main objective of the APS was to identify and quantify energy savings (electricity and natural gas) potential, GHG emission reductions and associated costs from demand side resources for the period from 2019-2038. This achievable potential modeling is used to inform:

- future energy efficiency policy and/or frameworks;

- program design and implementation; and

- assessments of Conservation and Demand Management (CDM) non-wires potential in regional planning.

1. The 2019 APS determined that both electricity and natural gas have significant cost-effective energy efficiency potential in the near and longer terms. In particular, the maximum achievable potential scenario is one scenario in the APS that estimates the available potential from all CDM measures that are cost effective from the provincial system perspective – i.e., they produce benefits from avoided energy and system capacity costs that are greater than the incremental costs of the measures. Under this scenario, the study shows that CDM measures have the potential to reduce summer electricity peak demand by up to 3,000 MW in the province over the 20-year forecast period and can produce up to 24 TWh of energy savings over the same period.

2. After scaling this level of forecasted maximum achievable savings potential to the local area, the committed savings that are expected to come from existing provincial and federal CDM programs as well as from codes and standards have been netted out and the remaining uncommitted achievable savings potential is presented below. This uncommitted potential provides an estimate of the amount of incremental CDM savings potential that is available to help address emerging local needs in the Northwest region.

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[7] More information about the 2019 Conservation Achievable Potential Study is available on the IESO website (link)
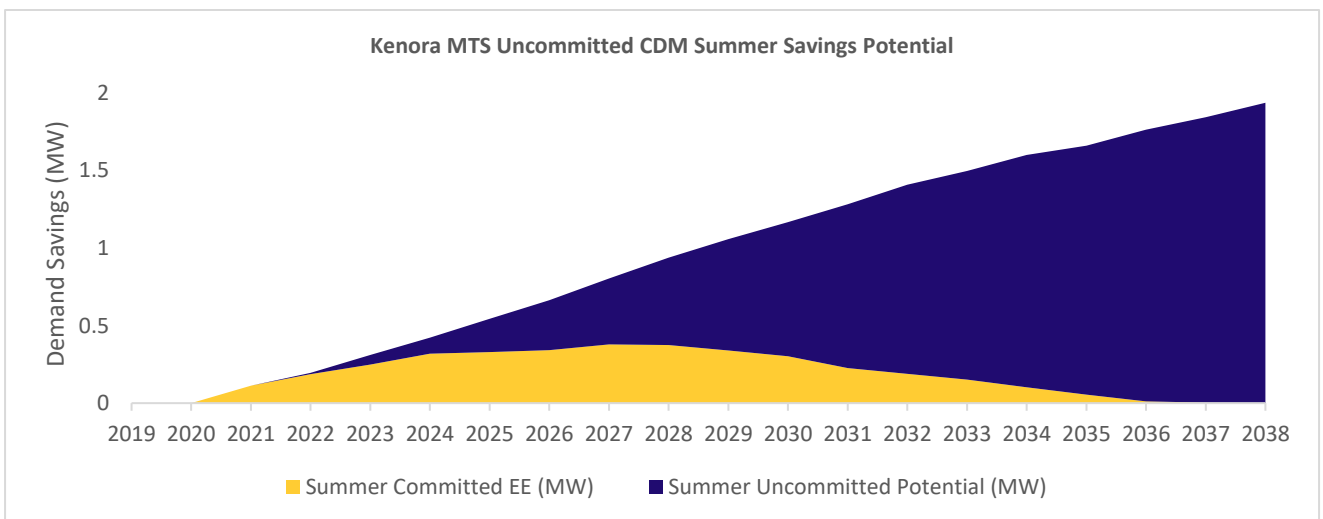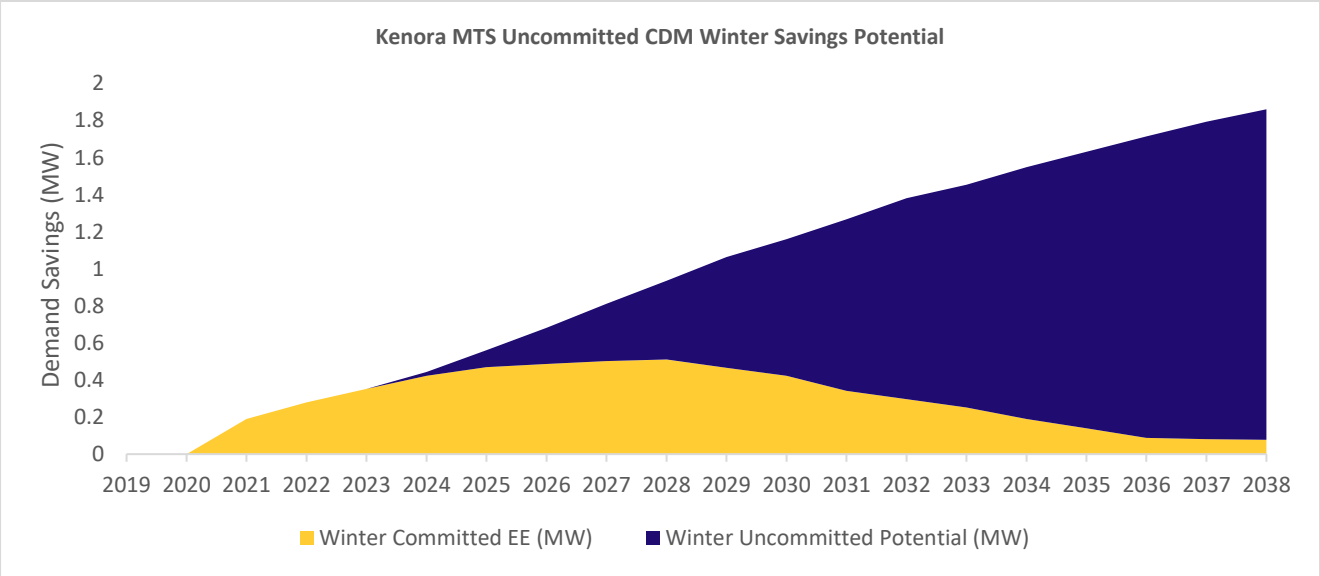
# E.1 Incremental CDM for Kenora MTS

Comparing the regional planning forecast at the Kenora MTS to the zonal energy forecast used for the 2019 APS, it is estimated that approximately 2.5% of the savings potential modeled in the Northwest zone is achievable at the Kenora MTS on average over the forecast period. The rate of zonal savings that is expected to be achievable at the Kenora MTS in each year is illustrated in the graph below.



Share of Northwest Zonal Potentential Achievable at Kenora MTS
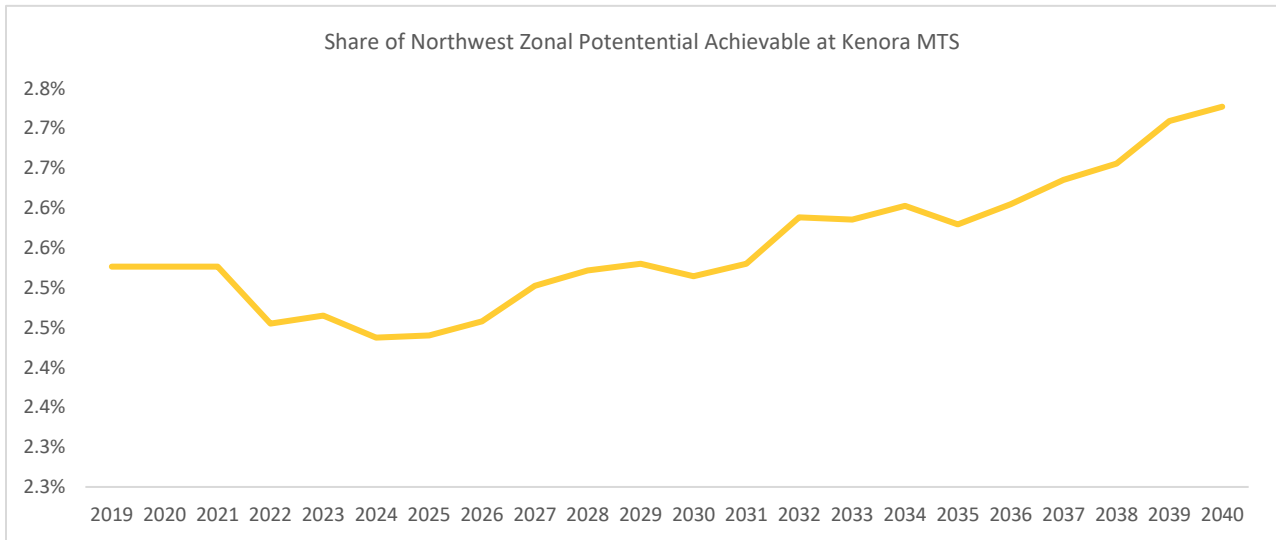
Applying these rates to Northwest zonal forecasted savings potential provides the maximum achievable savings potential that is expected to be achievable at Kenora MTS. In the near-term, a portion of these achievable savings opportunities are captured by the 2021-2024 CDM Framework programs. Overtime, new opportunities emerge with savings potential available across all sectors in this zone. The figures below illustrate the total committed savings potential that is expected to be achieved by existing programs as well as the uncommitted savings potential, which together add to the total forecasted maximum achievable potential for winter and summer.



Kenora MTS Uncommitted CDM Summer Savings Potential

■ Summer Committed EE (MW)   ■ Summer Uncommitted Potential (MW)

**Kenora MTS Uncommitted CDM Winter Savings Potential**

| Kenora MTS | 2026 | 2040 |
|---|---|---|
| Max Achievable CDM Potential Summer (MW) | 0.66 | 1.9 |
| Committed CDM Potential Summer (MW) | 0.34 | 0 |
| Uncommitted CDM Potential Summer (MW) | 0.32 | 1.9 |
| Max Achievable CDM Potential Winter (MW) | 0.68 | 1.9 |
| Committed CDM Potential Winter (MW) | 0.49 | 0.1 |
| Uncommitted CDM Potential Winter (MW) | 0.20 | 1.8 |

At the Kenora MTS, is estimated that this 1.9 MW of summer savings potential and 1.8 MW of winter potential would cost $7 million dollars to deliver over the forecast period.

# Appendix E – Economic Assumptions

The following is a list of the assumptions 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.

- Natural gas price forecast is as per Sproule Outlook @ Dawn used in the 2021 Annual Planning Outlook (APO).

- 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; the life of the line was assumed to be 70 years; and the life of the reciprocating engine generation and storage assets was assumed to be 30 years and 15 years respectively. Cost of asset replacement were included where necessary to ensure the same NPV study period.

- Development timelines for generation and storage were assumed to be 3 years.

- The size of the resource option was determined by a deterministic capacity assessment.

- A reciprocating gas engine was identified as one of the lowest-cost gas generation resource alternatives for the Northwest region, based on escalating values from a previous study independently conducted for the IESO.[8]

- A battery energy storage system was identified as another 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 2021 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB).

- 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 is capable of using existing resources to sufficiently charge to meet the hours of unserved energy.

- 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 fixed and variable operating and maintenance costs for the resource (i.e., battery energy storage system or gas generation).

- Carbon pricing assumptions are based on the proposed Federal carbon price increase of a carbon price that escalates to $170/tCO2e by 2030.  Thereafter, the $170/tCO2e assumption is held

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[8] New natural gas-fired generation was considered in the economic analysis for illustrative purposes to represent the lowest option of new generation.

constant in real dollars for the forecast period. The benchmark (tCO2e/GWh) for new gas facilities is assumed to be eliminated by 2030.

- 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.

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