Barrie/Innisfil Integrated Regional Resource Plan

Appendices June 2022

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The IESO recognizes the need for, and value of, transparency related to planning data underpinning the development of the Barrie/Innisfil IRRP. In addition to the data provided in these appendices in tabular form, the IESO has published the data in excel format on its website1.

[1] This file can be accessed in the link: https://www.ieso.ca/en/Get-Involved/Regional-Planning/GTA-and-Central-Ontario/Barrie-Innisfil

Appendix A. Overview of the Regional Planning Process

A.1 The Regional Planning Process

In Ontario, meeting the electricity needs of customers at a regional level is achieved through regional planning. This comprehensive process starts with an assessment of the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium and long term time frame 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. [2] The OEB endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, and to the former OPA's licence in October 2013. The licence changes required it to lead two out of four phases of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence became the responsibility of the IESO.

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

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

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.

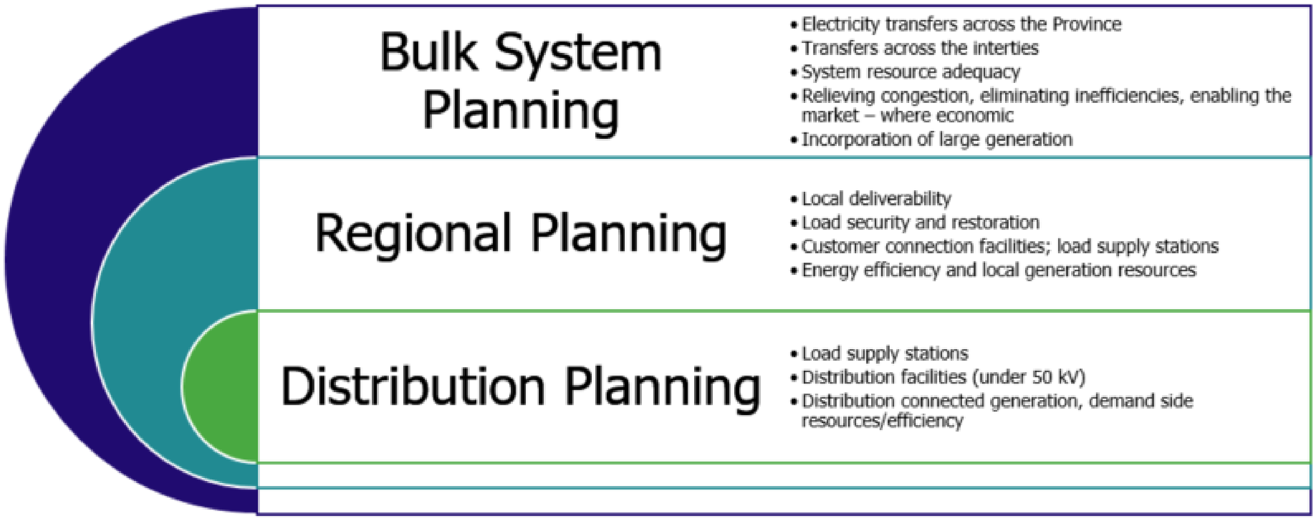
The final Needs Assessment Report, Scoping Assessment Outcome Report, IRRP and RIP are posted on the IESO's and the relevant transmitter's web sites, and may be referenced and submitted to the OEB as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments.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

This Appendix describes the methodologies used to develop the demand forecast (peak and duration) for the Barrie/Innisfil 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 sections that follow describe the method used by the IESO to determine the forecast starting point, the approaches and methods used by each LDC to forecast demand in their respective service area, the conservation and DG assumptions and the duration forecast methodology.

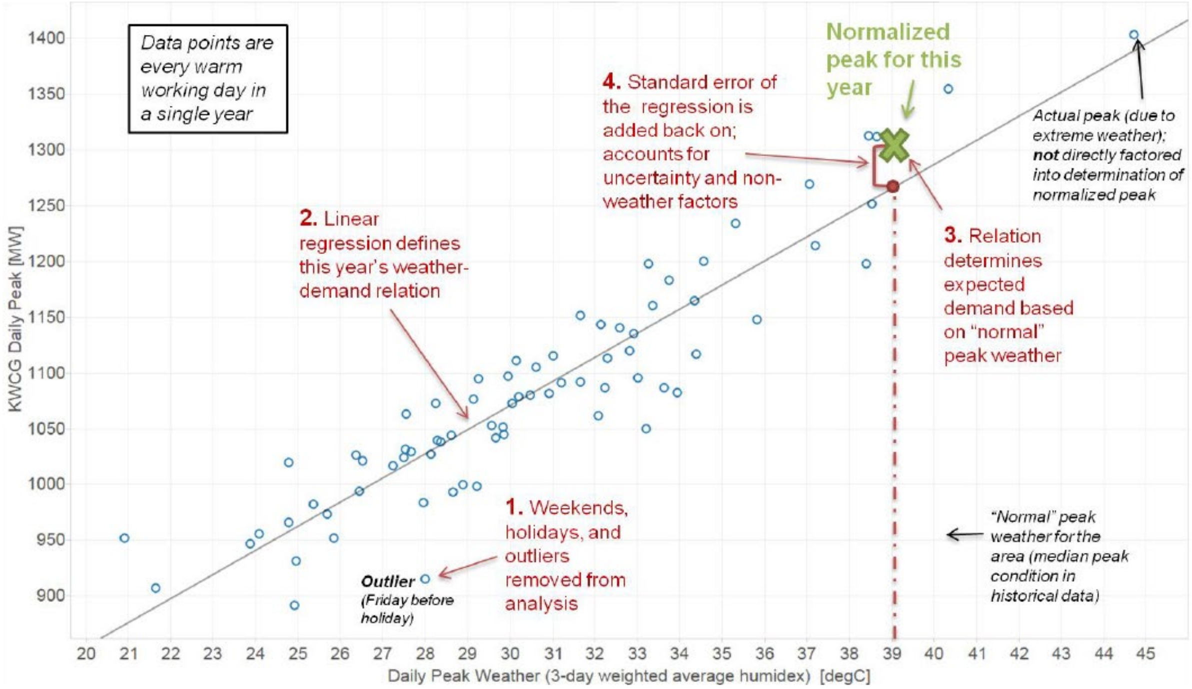
B.1 Method for Determining Forecast Starting Point

To develop a standardized starting point for the Barrie/Innisfil sub-region demand forecast, the following steps were performed:

- 5-year i.e., 2015-2020, 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

In order to weather-normalize the data, historical demand was adjusted to reflect the median peak weather conditions for each transformer station in the area for all historical years. Median peak refers to the expected peak demand under the most likely, or 50th percentile, weather conditions. This means that in any given year there is an estimated 50% chance that the actual peak demand will exceed this peak, and a 50% chance that the actual peak demand will be lower than this peak. The methodological steps are described in Figure 2; note that this is an illustrative example that was 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 (2020) 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 reliability of the electric power system generally require the use of extreme weather demand forecasts, or, expected demand under the hottest weather conditions (in the case of Barrie/Innisfil sub-region, which is a summer peaking region) that can be reasonably expected to occur. Peaks that occur during extreme weather are generally when the electricity system infrastructure is most stressed. The extreme weather adjustment factors used in the Barrie/Innisfil IRRP were calculated as per IESO's methodology for modelling extreme weather conditions, which determines the relationship between weather and demand for a given region in a given timeframe.

B.2 LDC Forecast Methodologies

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

- Alectra Utilities Inc.
- Hydro One Networks Distribution
- InnPower Corporation

B.2.1 Alectra Utilities Inc.

The Alectra Utilities long-term load forecast provides an indication as to where and how much the load increases are occurring. Alectra Utilities performs a load forecasting exercise annually.

Alectra Utilities performed a combination of two methods of forecasting to determine the long-term system capacity adequacy assessment:

- End-use analysis using the latest information available from municipal report; and
- Past system peak performance and trend (statistical) analysis

End-Use Analysis Using the Latest Information

Alectra Utilities reviewed economic development and outlook for different regions that include Ontario Government development, population growth and job growth projections, municipal economic analysis report, past housing completion statistics and future housing projection, Industrial, Commercial, Institutional (ICI) activities and news from media.

- **Population Growth**: Historical annual population growth was obtained from Regional Annual Economic and Municipal Development Review Reports. Long-term annual population projections were obtained from provincial and municipal official plan reports published by the Ontario government, and regional/municipal governments.
- **Employment Growth**: Historical employment and economic growth statistics reports published by Provincial and Municipal governments were used to extract the historic economic development and growth rates. Employment growth and structure projections were used to develop the long-term employment forecast categorized by the sector, industry and service types.
- **Housing Activities**: The number and mix of housing completions, vacancy rates and building permit activities in the Region/Municipal boundaries, and residential developments plan were reviewed. Plans of subdivisions and condominiums were obtained and analyzed to develop the long-term load forecast.
- **ICI Building Activity**: Industrial and Commercial development rate, commercial vacancy rate, industrial sale prices per square feet, total ICI construction and commercial/industrial building permits were obtained and compiled to develop the long-term load forecast.

Weather Correction

Alectra used weighted 3-day moving average temperature to correlate the peak demand and weather. Peak demand weather normalization is the process for estimating what peak demand would have occurred in a given time period if the weather had been normal (1 in 2). The weather normalized peak demand was used as the starting point for the forecast. Alectra used "1- in – 10" (extreme) weather (i.e., high temperatures) on peak demand[3].

[3] The 1 in 2 forecast was used to develop the gross IRRP median weather forecast. This was subsequently adjusted for extreme weather according to the methodology in Appendix B.1.

Other Factors

The other contributing factors to long-term load projections were CDM contribution and other government incentives and programs (i.e., Global Adjustment), emerging industrial technologies (i.e., Microgrid, battery storage, combined heat & power, etc.), newly introduced load types (i.e., electric vehicles, fleets) that were reviewed and assessed in load forecast procedure.

CDM

Alectra Utilities' load forecast was performed using current year's peak (weather normalized) as starting point. The impact of CDM programs in the previous years is reflected in the actual peak. The CDM for future years was considered in the forecast[4]

DG

Alectra Utilities' forecast considered the existing DG and DG connections forecasted over the horizon period.

Electrification of Transportation

Alectra Utilities continues to monitor the uptake of electric vehicles and projects related to electrification of transportation to better understand and determine the impact on local electricity needs. Alectra Utilities used the available information on EV adoption and evaluates the impact of the EVs at the peak.

Past System Peak Performance and Trend Analysis

The trend analysis was performed to forecast the system peak from historical peak demand results. The purpose of the trend analysis is to compare the results with end-use method to obtain more realistic long-term load projections considering the historical demand peak.

Conclusion

There is a level of uncertainty with respect to any forecasting exercise. Any major unexpected changes to assumptions, economic pressure or crisis events, government directives and other social/economic/political events that can impose changes and that were not contemplated at the time of forecasting will be reviewed and the forecast will be adjusted annually accordingly to reflect the changes.

B.2.2 Hydro One Networks Distribution.

Hydro One Distribution services the areas of South Georgian Bay Muskoka region that are not serviced by other LDCs. It supplies power through various stations included in the study area.

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[4] Note that, while the impact of existing/past CDM programs were included in the starting point, future CDM program impact was forecasted by the IESO

Hydro One Distribution used both econometric and end-use forecasting to develop the 20-year load forecast provided to the IESO. A baseline forecast (MW station peak in the base year) was developed, taking into account such factors as normal operating conditions, coincident peak loading, and extreme weather conditions.

For the Barrie/Innisfil IRRP forecast, Hydro One Distribution used the weather corrected peak demand levels for the stations serving Hydro One customers. From the established baseline year, a growth rate (%) was applied to station demand levels to provide forecast values, at each station, within the study frame.

Assumptions included in the growth rate can be related to such factors as: Ontario GDP growth rate, housing statistics, the intensification of urban developments (i.e., MW/sq.ft); and electrification trends (e.g., more vehicles switching from gas to electrical vehicles).

Where possible, detailed information about load growth, based on local knowledge and or municipal/provincial plans, was used to augment the forecast values within the study period.

B.2.3 InnPower Corporation.

As one of the fastest growing electrical utilities in Ontario, InnPower maintains a service territory of 292 square kilometers and provides services to Town of Innisfil and South of Barrie.

InnPower's load forecast methodology was mainly based on the actual load requests received from customers (Developers/ Individuals). This information provided the planning inputs which were categorized in three main sectors of residential, ICI and employment load demand.

The calculated baseline forecast was then adjusted considering factors such as normal operating conditions, coincident peak loading, municipal fact sheet on number of issued building permits, population growth rate in the area and the historical peak load records.

In order to capture the housing market demand, InnPower considered the historical number of energized units in the previous years to regulate the long-term forecast on the annual basis. Also, from 2021, demand for electrical vehicles was added to the load forecast as a new factor impacting the peak demand and required capacity.

Winter peak forecasting was projected based on the historical data in comparison to the summer peak, given the fact that peak load trend for InnPower is in summer.

B.3 Conservation Assumptions in Barrie/Innisfil Forecast

Conservation & Demand Management (CDM) measures can reduce the electricity demand and its impact can be separated into the two main categories: Building Codes & Equipment Standards, and Energy Efficiency Programs. The assumptions used for the Barrie/Innisfil IRRP forecast are consistent with the CDM assumptions in the IESO's 2020 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 provincial level to the Essa transmission zone and then allocated to the Barrie/Innisfil sub-region. This section describes the process and methodology used to estimate CDM savings for the Barrie/Innisfil 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 Essa zone and compared with the gross peak demand forecast for the zones 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 sectoral annual peak reduction percentages of each year were applied to the demand that was forecasted at each station in order to develop an estimate of the peak demand impacts from codes and standards as well as energy efficiency programs. The forecasted savings will decay over time as the energy efficiency measures come to the end of their effective useful lives.

B.3.2 Estimate Savings from Conservation Programs

In addition to codes and standards, the delivery of energy efficiency programs reduces electricity demand. The impact of existing and committed energy efficiency programs were analyzed, which include the 2021 – 2024 CDM Framework and other provincial and federal EE programs. A top down approach was used to estimate the peak demand reduction due to the delivery of EE programs, from provincial to Essa zone to the stations in the region. Persistence of the peak demand savings from energy efficiency programs was also considered over the forecast period.

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. Summer peak demand savings by TS were 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, along with 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 Summer Peak Demand Savings (MW) Due to Codes and Standards and Funded CDM 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
Alliston TS	1.3	2.6	3.9	5.4	6.2	6.7	7.3	7.8	8.2	8.4	8.4	8.5	8.5	8.5	8.5	8.5	8.7	8.8	8.9	9.0
Barrie TS	0.8	1.7	3.2	4.8	6.0	6.9	8.0	8.9	9.7	10.5	10.8	10.9	10.8	10.7	10.6	10.6	10.7	10.8	10.9	10.9
Everett TS	0.9	1.8	2.6	3.6	4.2	4.5	4.9	5.2	5.4	5.6	5.7	6.0	6.2	6.5	7.0	7.5	8.0	8.4	8.8	9.2
Midhurst TS	2.9	5.7	8.0	10.9	12.7	13.6	14.7	15.4	16.1	16.7	16.7	16.9	16.9	16.9	16.9	17.1	17.4	17.6	17.9	18.2

B.4 Distributed Energy Resources Assumptions

Besides conservation savings, the expected peak contribution 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
Alliston TS	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.21	0.04	0.03	0.03	0.00	0.00	0.0
Barrie TS	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.22	0.17	0.10	0.10	0.06	0.06	0.06	0.00	0.00	0.0
Everett TS	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.27	0.26	0.20	0.20	0.16	0.16	0.07	0.00	0.00	0.0
Midhurst TS	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.02	4.93	1.85	0.18	0.04	0.02	0.00	0.00	0.00

DG capacity factors were applied using factors from the Reliability Outlook (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 assumptions above, forecasts were adjusted to extreme weather. The final peak demand forecasts, by station, are provided below:

Table 3 | Summer 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
Alliston TS	132.6	136.1	139.1	140.6	142.3	146.4	149.9	153.9	157.0	159.5	160.9	163.5	166.2	168.9	171.7	174.2	176.8	179.3	181.8	184.3
Barrie TS	95.7	105.3	131.6	144.4	157.2	171.1	186.6	200.9	213.9	225.7	237.6	239.5	241.7	243.7	245.9	247.6	249.3	251.1	252.8	254.5
Everett TS	82.1	83.1	84.2	85.0	86.2	87.8	89.4	91.1	92.9	94.8	98.1	102.5	109.1	116.6	127.3	137.4	146.6	153.7	160.8	167.9
Midhurst TS	271.9	275.0	257.5	259.7	263.2	267.2	271.1	275.5	280.0	284.7	289.5	294.4	299.6	307.9	314.9	319.7	324.4	329.3	334.2	339.1

B.6 Duration Forecast Methodology

B.6.1 General Methodology

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

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

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

- Calendar factors (such as holidays and days of the week)
- Weather factors (including temperature, dew point, wind speed, cloud cover, and fraction of dark; both weekday and weekend heating, cooling, and dead band splines were modelled)
- Demographic factors (population data[5])
- 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 values for calendar, demographic, and economic variables were incorporated in a relatively straightforward manner, the unreliability of long-term weather forecasts necessitated a different approach for predicting the impact of future weather.

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

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

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

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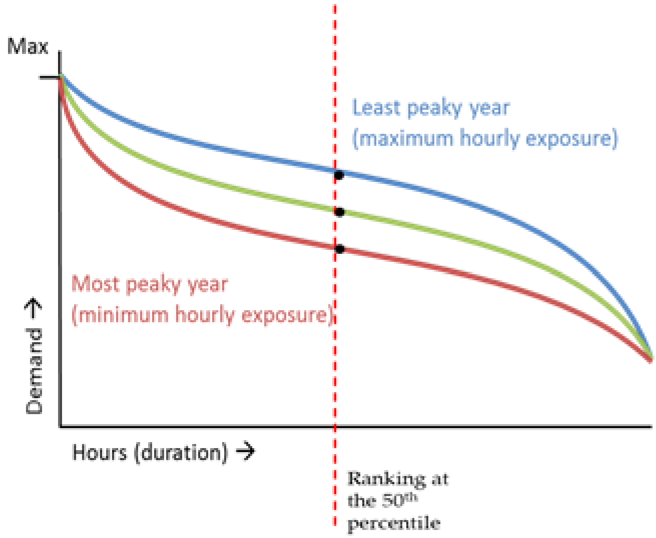
[5] Sourced from the Ministry of Finance and Statistics Canada
[6] Sourced from the Centre for Spatial Economics, IHS Markit Ltd., and the Conference Board of Canada

Figure 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 was the "Median Peak" (median profile, green curve).

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

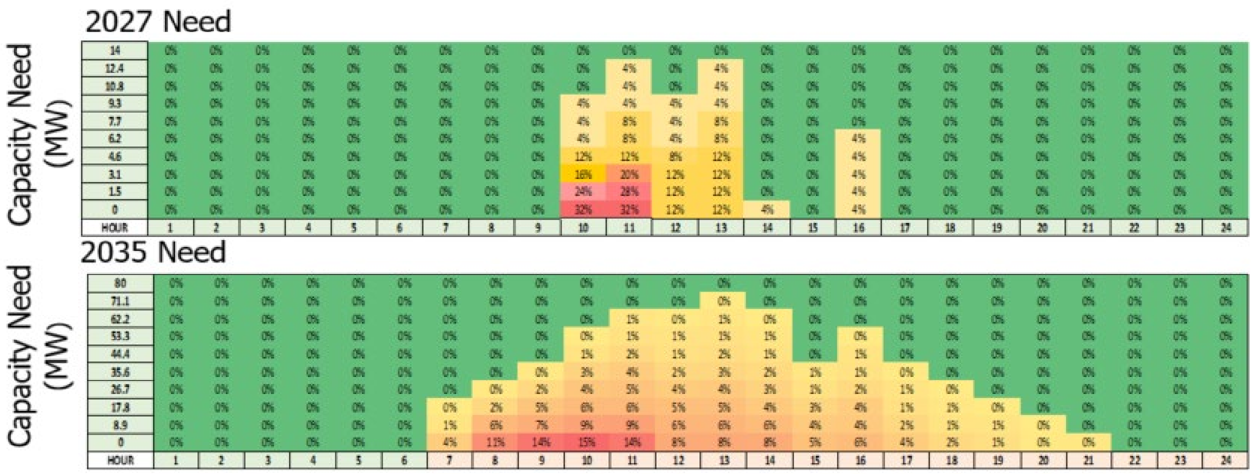
B.6.2 Hourly Need Characterization

Barrie TS Capacity Need

Table 4 | Barrie Capacity Need Key Metrics

Key Metrics	2027	2035
Limit (MW)	172.8	172.8
Capacity Need (MW)	13.8	73
Number of Events	8	146
Maximum Energy Per Event (MWh)	53.15	565.1
Maximum Event Length (Hours)	6	15
Average Event Length (Hours)	2.8	5.7
Total Energy (MWh)	118.5	15,379

Figure 4 | Barrie TS Capacity Need Daily Heat Map (% of Need Hours at or Above MW value)

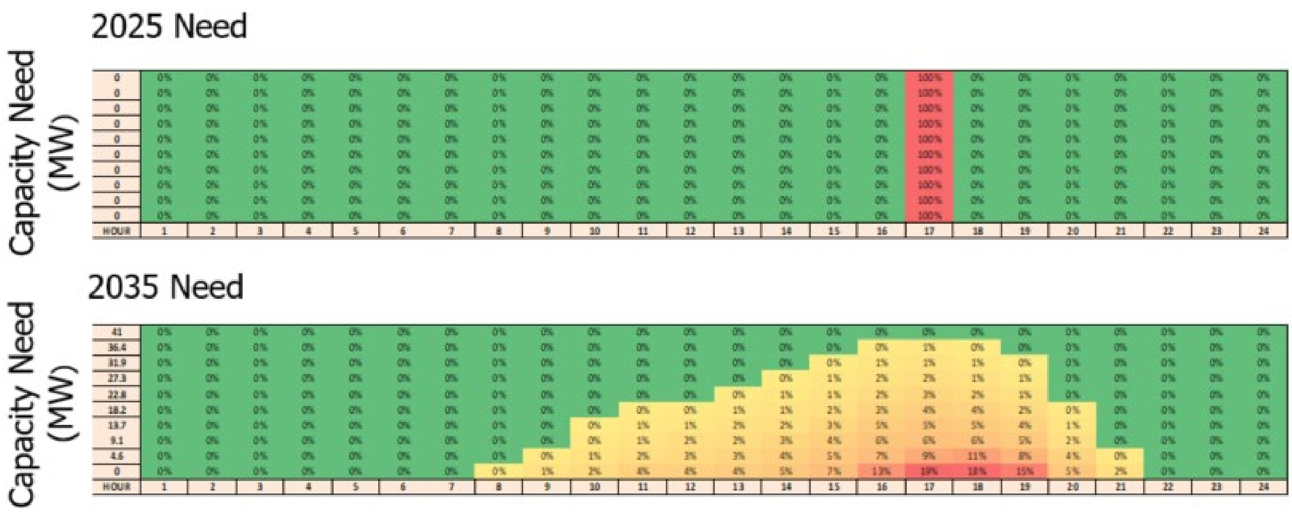


Everett TS Capacity Need

Table 5 | Everett Capacity Need Key Metrics

Key Metrics	2027	2035
Limit (MW)	86	86
Capacity Need (MW)	0.2	41.25
Number of Events	1	221
Maximum Energy Per Event (MWh)	0.2	320.2
Maximum Event Length (Hours)	1	14
Average Event Length (Hours)	1	4.6
Total Energy (MWh)	0.2	9,935.4

Figure 5 | Everett TS Capacity Need Daily Heat Map (% of Need Hours at or Above MW value)

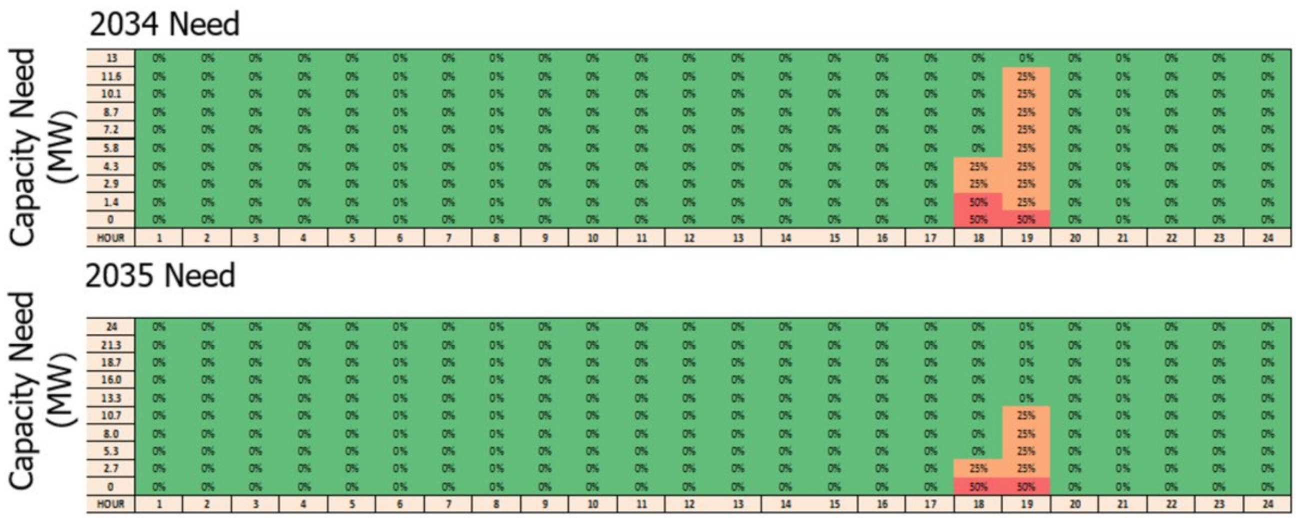


MxE System Capacity Need

Table 6 | MxE System Capacity Need Key Metrics

Key Metrics	2034	2035
Limit (MW)	581	581
Capacity Need (MW)	12.8	23.87
Number of Events	5	8
Maximum Energy Per Event (MWh)	20.5	47.1
Maximum Event Length (Hours)	2	3
Average Event Length (Hours)	1.6	2.1
Total Energy (MWh)	53.9	161.6

Figure 6 | MxE Capacity Need Daily Heat Map (% of Need Hours at or Above MW value)



Appendix C. Options and Assumptions

C.1 Economic Assumptions

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

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 0.78 for the study period.
- The NPV analysis was conducted using a 4% real social discount rate. Sensitivities at 2% and 8% were performed. An annual inflation rate of 2% is assumed.
- The life of the station upgrades was assumed to be 45 years; and the life of the storage assets was assumed to be 30 years and 10 years respectively. The life of the storage asset was based 3600 cycles, which is assumed to be used to serve the local need first, and then global energy and ancillary services for the rest of the year. 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.
- An energy storage facility was identified as a low-cost resource alternative. Total energy storage system costs are composed of capacity and energy costs (I.e. energy storage devices are constrained by their energy reservoir). The estimated overnight cost of capital assumed is about $900-$1600/kW (2021 CAD) depending on the storage capacity to energy requirement, based on escalating Ontario-specific values from a previous study independently conducted for a collection of entities including the IESO.
- The size of the resource option was determined by deterministic capacity assessment.
- Sizing of the 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 gas resources to sufficiently charge to meet the hours of unserved energy.
- System capacity value was $144k/MW-yr (2021 CAD) based on an estimate for the Cost of the Marginal New Resource (Net CONE), a new SCGT in southwestern Ontario, with a sensitivity of +/- 25% assessed. Note that the IESO's Pathways to Decarbonization Study is exploring different scenarios regarding new capacity to meet provincial resource adequacy needs.

- Production costs were determined based on energy requirements to serve the local reliability need, assuming fixed operating and maintenance costs of $12/kW-yr for storage, variable operating and maintenance costs of $5/MWh and a heat rate of 12 MMBtu/MWh for gas-fired resources.
- Carbon pricing assumptions are based on the proposed Federal carbon price increase, from $50/t in 2022 to $170/t by 2030, and applied to a facility's production. A sensitivity of up to +225% was assessed on the carbon costs for the gas-fired generation option to assess the risk potential policy changes to the current carbon pricing strategy.
- 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.

C.2 Wires Options for Barrie TS Capacity Need

Table 7 presents the wires options to address the increased demand growth served by Barrie TS and the supply capacity constraint at the 44 kV feeder level. These wires options were formulated from the detailed options analysis conducted after the South Georgian Bay Muskoka Needs Assessment.

Table 7 | Wires Alternative Comparison for Barrie TS Capacity Need

Alternatives	InnPower to connect to existing Alectra feeder as embedded customer	Additional 44 kV feeder position from Barrie TS	Load existing 44 kV supply feeders beyond normal capacity	Provide 230 kV tap connection to Innisfil service territory for new TS
Scope/ Proposal	To utilize spare capacity at Barrie TS, this alternative will require Inn Power to build a distribution tap to the closest Alectra owned feeder and utilize spare capacity (if available). For this to occur, both station capacity and individual feeder capacity must be within limits.	InnPower will be supplied with 2-44 kV feeders from Barrie TS once the BATU project is completed. This alternative seeks to install a 3rd feeder to provide additional supply capacity.	InnPower will be supplied with 244kV feeders from Barrie TS once the BATU project is completed. This alternative will require Hydro One Dx to increase loading these two feeders beyond the normal planning capacity while staying within the overall station capacity offered by BATU. This alternative would increase each feeder supply capacity by 10MW/feeder for a total of 20MW.	This alternative provides increases supply capacity for InnPower by constructing a new 230/27.6kV transformer substation and connecting to the new 230kV transmission lines (E28B/E29B) that will be available post BATU.
Impacted Participants	Alectra InnPower	Hydro One Tx, Dx InnPower	Hydro One Dx InnPower	Hydro One Tx InnPower
Transmission Considerations	OGCC presently utilizes Barrie TS M4 feeder as a backup supply and this supply requirement for Hydro One will remain in place following the completion of the BATU project.	Barrie TS will be built to follow H1 standard 230/44kV Jones arrangement with 8 feeder positions. To accommodate an additional feeder, the existing layout and station footprint will require redesign. Modifications to the low voltage steel structure, access road, relocation of capacitor banks, and fence extension will be required. Note:	No significant transmission considerations.	Provide approximately 7km new 230kV double circuit line tap from E28B/E29B circuits to the new substation.
Distribution Considerations	Alectra M4 feeder provides low exposure backup for OGCC, and its short feeder length and geographic location restricts new load/tap connections. Alectra has indicated the feeder capacity is not available on the remaining feeders closest to InnPower service territory, due to its existing load and anticipated growth.	There are known physical challenges due to clearances adding additional complexity for a new feeder egress. To build a new feeder, an underground egress would be required transitioning to an overhead lines and will follow a similar path to the existing feeders travelling south to Innisfil.	Voltage support will be required along each of the 2-44kV feeders to maintain acceptable voltage profile on the feeders. Further Dx studies (coordinated with InnPower) are needed to determine the location of regulating stations (RS)	Inn Power will construct and own a new 230/27.6 83MVA transformer station.

Alternatives	InnPower to connect to existing Alectra feeder as embedded customer	Additional 44 kV feeder position from Barrie TS	Load existing 44 kV supply feeders beyond normal capacity	Provide 230 kV tap connection to Innisfil service territory for new TS
Implementation Timing	2-3yrs	2-3yrs	2-3yrs	3-5 years
Solution Valid Until	50MW+0MW* =50MW 2025 Note: * capacity is not available at this time.	50MW+25MW=75MW 2027	50MW+20MW=70MW 2027	50MW+ (100MW) >2030
Costs	Costs = Not Applicable. Costs have not been explored as there is no available feeder capacity. Should capacity become available in the future, estimates can be obtained from the working group if practical to do so.	HONI Transmission - $5M HONI Distribution – $15M Total - $20M The cost of a new feeder position will be substantially higher than what would normally be expected for this type of work for both Hydro One and Hydro One Distribution due to the egress challenges outside the station and physical space limitations inside Barrie TS.	HONI Transmission – N/A HONI Distribution - $8M Total - $8M	HONI Transmission - $14M InnPower - $30M Total - $44M
Meets the Need	This solution is only viable if OGCC backup control strategy changes, and feeder capacity on the closest feeders from Alectra becomes available. Any spare capacity that would be available if this alternative proceeds would still fail to meet the full supply needs within the study period, and will need to be combined with alternate solutions.	A new feeder position will provide up to 25MW supply capacity, which will help to delay the need to 2027. Another solution will need to be implemented to meet the full capacity needs beyond 2027 which would be at additional cost to this alternative or to replace this alternative. This alternative is not viable as a standalone option and still must be combined with options 4 to meet supply needs within the study period.	This alternative will provide up to 20MW increased supply capacity which will help to delay a capacity need until 2027. Another solution will need to be implemented to meet the full capacity needs beyond 2027 which would be at additional cost to this alternative or to replace this alternative. This alternative is not viable as a standalone option and still must be combined with option 4 to meet supply needs within the study period.	This alternative will provide the supply capacity needed well beyond the study period. The station is presently being sized with 83MVA transformers will provide sufficient supply capacity for area load growth and this alternative can be utilized as standalone solution to meet the needs without additional interim investments.

Appendix D. Planning Study Results

D.1. Introduction

This document provides the scope of the technical study for both the Parry Sound/Muskoka and Barrie/Innisfil Integrated Regional Resource Plans (IRRPs). Both sub-regions form part of the larger South Georgian Bay/Muskoka (SGBM) region.

D.1.1 Area of Study

The area of study encompasses the SGBM region, bounded by Parry Sound Transformer Station (TS) to the north, Minden TS to the east, Everett TS to the south, and Meaford TS to the west. An overview of the SGBM Region can be seen in Figure 1 below. The largest transmission connected generators in the area are Des Joachims GS (430 MW, hydroelectric) to the east and Henvey Inlet Wind (300 MW, wind) to the north.

Figure 1 - Overview of SGBM Region

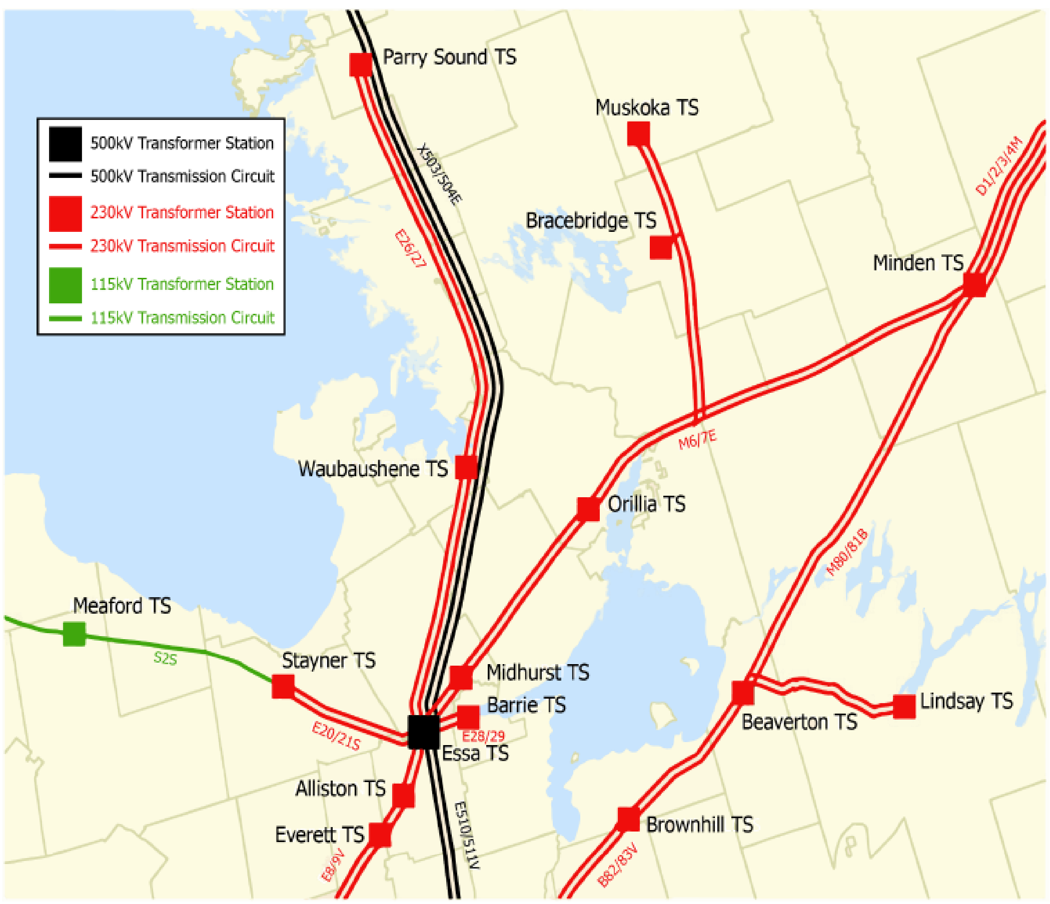
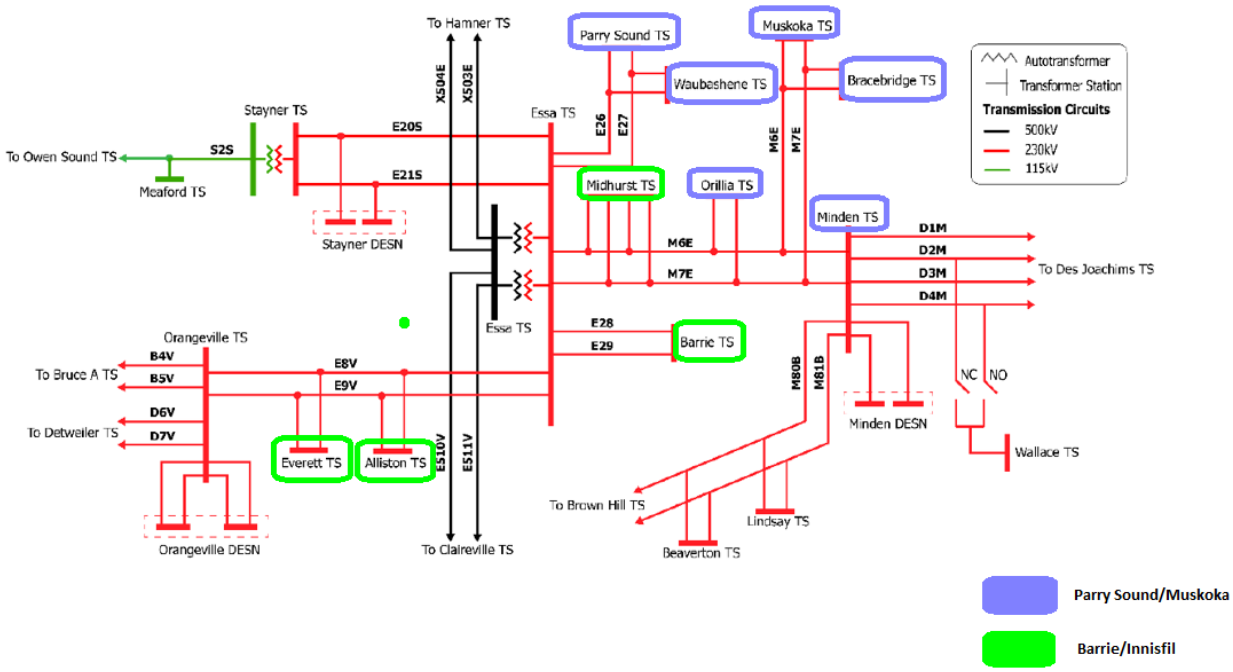


Figure 2 - Electricity Infrastructure in the SGBM Region



The region is currently supplied from 115 kV and 230 kV transmission lines and stations that connect at Essa TS. The 500/230 kV autotransformers at Essa TS provide the major source of supply to the area. As an outcome of the last planning cycle, the 115 kV supply in the region (from Essa TS to Barrie TS) is currently being converted to a 230 kV supply, and will be completed in 2023. An overview of the electrical infrastructure that currently supplies the region is provided in the single line diagram in Figure 2.

D.2. Scenarios Assessed

D.2.1 Summary of Scenarios

This section outlines the scenarios assessed by the technical study. It covers both summer and winter scenarios of the SGBM area.

Table below summarizes the scenarios assessed. Further details on the load forecast, local generation assumption, and interface flows are discussed in the subsequent subsections. Note that all scenarios assume peak summer load conditions consistent with the IRRP forecast.

Table 1 - Summary of Scenarios to be Assessed

Scenario Name	Local Generation	Interface Flows	Contingencies Assessed
Summer A	All I/S[7]	Flow South: 1,296 MW	N-1, N-2, N-1-1
Winter A	All I/S[8]	Flow South: 303 MW	N-1, N-2, N-1-1
Summer B	Des Joachims GS O/S	Flow South: 1,296 MW	N-1, N-2
Winter B	Des Joachims GS O/S	Flow South: 305 MW	N-1, N-2
Summer C	Henvey Wind Inlet GS O/S	Flow South: 1,296 MW	N-1, N-2
Winter C	Henvey Wind Inlet GS O/S	Flow South: 304 MW	N-1, N-2

D.2.2 Load Forecast

The initial need identification study uses net peak summer forecast snapshots in 2022, 2030, and 2040 (end of planning horizon). The coincident station level forecast is provided in Table 2 below.

Where needs were identified, further studies were performed to refine the need and determine the exact load level/year the need occurs in. Coincident forecasts for select groups of stations were also constructed where appropriate such as when assessing a circuit capacity need serving multiple stations.

Where appropriate, hourly load profiles were developed to aid in the evaluation of non-wires alternatives.

[7] This assumes summer capacity factors of 31% and 14% for hydroelectric and wind power, respectively.
[8] This assumes winter capacity factors of 59% and 38% for hydroelectric and wind power, respectively

A load's power factor of 0.9 at the load was used (without consideration for the status of low-tension capacitor banks[9]).

Table 2 – SGBM Area Coincident Summer Demand Forecast

Station Name	2022 (MW)	2030 (MW)	2040 (MW)
Alliston TS	120.4	141.2	163.2
Barrie TS	81.6	174.9	197.3
Beaverton TS	68.1	70.9	86.0
Bracebridge TS	26.8	27.0	28.6
Everett TS	82.2	93.7	166.0
Lindsay TS	82.5	87.5	102.4
Meaford TS	33.3	34.2	39.1
Midhurst TS	271.4	281.0	334.8
Minden TS	35.7	37	43.5
Muskoka TS	108.2	119.5	131.1
Orangeville TS	139	160.4	189
Orillia TS	102.4	117.2	131.6
Parry Sound TS	41.6	50.3	54.4
Stayner TS	122.6	133.3	160.3
Wallace TS	29.9	30.4	32.0
Waubashene TS	78.7	87.2	104.5

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

Table 3 – SGBM Area Coincident Winter Demand Forecast

Station Name	2022 (MW)	2030 (MW)	2040 (MW)
Alliston TS	97.7	116.7	134.7
Barrie TS	68.8	152.7	171.4
Beaverton TS	77.0	80.5	88.1
Bracebridge TS	32.7	33.2	34.9
Everett TS	55.9	63.8	130.8
Lindsay TS	87.7	93.4	101.7
Meaford TS	43.5	44.8	54.4
Midhurst TS	185	192.6	223.6
Minden TS	52.6	54.7	61.7
Muskoka TS	139.2	151.8	160.8
Orangeville TS	119.8	134.9	162.7
Orillia TS	101	116.2	125.3
Parry Sound TS	56.4	65.9	70.7
Stayner TS	132.5	142.5	172.1
Wallace TS	38.0	38.8	40.8
Waubashene TS	77.7	83.4	91.5

D.2.3 Local Generation Assumptions

Generation facilities are tabulated in Table 4. The base case used dependable generation (i.e., unforced capacity or "UCAP") based on Power System Planning's Capacity Tally for hydroelectric power and assumptions from the 2020 Annual Planning Outlook (APO) for wind power. Scenarios with up to four Des Joachims GS units and all of Henvey Inlet Wind out of service were also studied. Distributed-connected generation (DG) was netted out in the load forecast (load modifier) based on summer peak contribution factors consistent with the Reliability Outlook.

Table 4 – Local Dependable Generation Capacity

Facility Name	Installed Capacity	Seasonal Capacity
Des Joachims GS	430 MW	Summer: 133.35 MW Winter: 253.7 MW
Henvey Wind Inlet GS	300 MW	Summer: 42 MW Winter: 114 MW

D.2.4 Major Interface Flows

- The Flow North/Flow South (FN/FS) interface comprises the circuits that connect the Essa Zone and Northeast Zone. This includes the two 500 kV circuits connecting Hanmer TS to Essa TS and one 230 kV circuit connecting Otto Holden TS to Des Joachims TS. The FS interface is defined identically to the FN interface, but the power transfer is measured in the reverse direction. FN transfer capability is important to reliably supply demand in the Northeast and Northwest zones, as well as facilitate exports to Manitoba, Minnesota and Québec; FS transfer capability is important to deliver imports and supply from the Northwest and Northeast Zones to the rest of the province.
- FN and FS transfers can be limited under certain conditions to ensure acceptable voltage and stability performance (e.g., FN can be limiting under low water conditions and sensitive to demand; and FS can be limiting under heavy water conditions). As of the 2020 APO, FN is limited to 1,500 MW while FS is limited to 2,100 MW.

D.3 System Topology

As mentioned in Section 1, the region is currently supplied from 115 kV and 230 kV transmission lines and stations that connect at Essa TS. The 500/230 kV autotransformers at Essa TS provide the major source of supply to the area.

Table 5 and Table 6 below list the monitored circuit sections in the SGBM area for summer and winter seasons, respectively. Note that the 500 kV circuits are not included.

Table 5 - Summer Ratings of Monitored Circuits and Ratings

Circuit Name	From	To	Continuous	LTE	STE
D1M	Des Joachims TS	Minden TS	550	550	550
D2M	Des Joachims TS	Otter Creek JCT	550	550	550
D2M	Otter Creek JCT	Minden TS	550	550	550
D2M	Otter Creek JCT	Wallace JCT	550	550	550
D2M	Wallace JCT	Wallace TS	550	550	550
D3M	Des Joachims TS	Minden TS	550	550	550
D4M	Des Joachims TS	Otter Creek JCT	550	550	550
D4M	Otter Creek JCT	Minden TS	550	550	550
E20S	Essa TS	Stayner TS	840	1090	1210
E21S	Essa TS	Stayner TS	840	1090	1210
E26	Essa TS	Waubaushene JCT	840	1060	1160
E26	Holmur JCT	Parry Sound JCT	840	1090	1400
E26	Holmur JCT	Holmur SS	840	1050	1140
E26	Parry Sound JCT	Parry Sound TS	840	1090	1400
E26	Waubaushene JCT	Waubaushene TS	840	1090	1400
E26	Waubaushene JCT	Holmur JCT	840	1050	1140

Circuit Name	From	To	Continuous	LTE	STE
E27	Essa TS	Waubaushene JCT	840	1090	1250
E27	Holmur JCT	Parry Sound JCT	840	1090	1250
E27	Holmur JCT	Holmur SS	840	1050	1140
E27	Parry Sound JCT	Parry Sound TS	840	1090	1250
E27	Waubaushene JCT	Waubaushene TS	840	1090	1400
E27	Waubaushene JCT	Holmur JCT	840	1090	1250
E28	Allandale TPS JCT	Barrie TS	1160	1530	1830
E28	Allandale TPS JCT	Allandale TPS	550	550	550
E28	Essa TS	Allandale TPS JCT	1160	1530	1830
E29	Allandale TPS JCT	Barrie TS	1160	1530	1830
E29	Allandale TPS JCT	Allandale TPS	550	550	550
E29	Essa TS	Allandale TPS JCT	1160	1530	1830
E8V	Alliston JCT	Everett JCT	840	1090	1400
E8V	Alliston JCT	Alliston TS	840	1090	1400
E8V	Alliston JCT	Alliston JCT	840	1090	1400
E8V	Essa TS	Alliston JCT	840	1090	1400
E8V	Everett JCT	Orangeville TS	840	1040	1130
E8V	Everett JCT	Everett TS	840	1090	1210
E9V	Alliston JCT	Everett JCT	840	1090	1400
E9V	Alliston JCT	Alliston TS	840	1090	1400
E9V	Alliston JCT	Alliston JCT	840	1090	1400
E9V	Essa TS	Alliston JCT	840	1090	1400
E9V	Everett JCT	Orangeville TS	840	1090	1400

Circuit Name	From	To	Continuous	LTE	STE
E9V	Everett JCT	Everett TS	840	1090	1210
M6E	Bracebridge JCT	Bracebridge TS	810	810	810
M6E	Bracebridge JCT	Muskoka TS	550	550	550
M6E	Cooper's Falls JCT	Orillia TS	440	440	440
M6E	Cooper's Falls JCT	Bracebridge JCT	550	550	550
M6E	Midhurst TS	Essa TS	840	1070	1180
M6E	Minden TS	Cooper's Falls JCT	440	440	440
M6E	Orillia TS	Midhurst TS	550	550	550
M7E	Bracebridge JCT	Muskoka TS	770	770	770
M7E	Cooper's Falls JCT	Orillia TS	550	550	550
M7E	Cooper's Falls JCT	Bracebridge JCT	770	770	770
M7E	Midhurst TS	Essa TS	840	1090	1230
M7E	Minden TS	Cooper's Falls JCT	550	550	550
M7E	Orillia TS	Midhurst TS	770	770	770
M80B	Beaver JCT	Brown Hill TS	840	1090	1210
M80B	Beaver JCT	Beaverton JCT	840	1090	1400
M80B	Beaverton JCT	Beaver JCT	840	1090	1270
M80B	Beaverton JCT	Lindsay TS	840	1090	1400
M80B	Minden TS	Beaverton JCT	840	930	970
M81B	Beaver JCT	Beaverton JCT	840	1090	1400
M81B	Beaver JCT	Brown Hill TS	840	1090	1210
M81B	Beaverton JCT	Lindsay TS	840	1090	1200
M81B	Beaverton JCT	Beaver JCT	840	930	970

Circuit Name	From	To	Continuous	LTE	STE
M81B	Minden TS	Beaverton JCT	840	930	970
S2S	Meaford TS	Stayner TS	590	770	850
S2S	Owen Sound TS	Meaford TS	590	770	950

Table 6 - Winter Ratings of Monitored Circuits and Ratings

Circuit Name	From	To	Continuous	LTE	STE
D1M	Des Joachims TS	Minden TS	750	750	750
D2M	Des Joachims TS	Otter Creek JCT	750	750	750
D2M	Otter Creek JCT	Minden TS	750	750	750
D2M	Otter Creek JCT	Wallace JCT	750	750	750
D2M	Wallace JCT	Wallace TS	750	750	750
D3M	Des Joachims TS	Minden TS	750	750	750
D4M	Des Joachims TS	Otter Creek JCT	750	750	750
D4M	Otter Creek JCT	Minden TS	750	750	750
E20S	Essa TS	Stayner TS	1020	1230	1340
E21S	Essa TS	Stayner TS	1020	1230	1340
E26	Essa TS	Waubaushene JCT	1020	1200	1300
E26	Holmur JCT	Parry Sound JCT	1020	1230	1510
E26	Holmur JCT	Holmur SS	1020	1190	1280
E26	Parry Sound JCT	Parry Sound TS	1020	1230	1510
E26	Waubaushene JCT	Waubaushene TS	1020	1230	1510
E26	Waubaushene JCT	Holmur JCT	1020	1190	1280
E27	Essa TS	Waubaushene JCT	1020	1230	1370
E27	Holmur JCT	Parry Sound JCT	1020	1230	1370
E27	Holmur JCT	Holmur SS	1020	1190	1280
E27	Parry Sound JCT	Parry Sound TS	1020	1230	1370
E27	Waubaushene JCT	Waubaushene TS	1020	1230	1510

Circuit Name	From	To	Continuous	LTE	STE
E27	Waubaushene JCT	Holmur JCT	1020	1230	1370
E28	Allandale TPS JCT	Barrie TS	1420	1720	2000
E28	Allandale TPS JCT	Allandale TPS	750	750	750
E28	Essa TS	Allandale TPS JCT	1420	1720	2000
E29	Allandale TPS JCT	Barrie TS	1420	1720	2000
E29	Allandale TPS JCT	Allandale TPS	750	750	750
E29	Essa TS	Allandale TPS JCT	1420	1720	2000
E8V	Alliston JCT	Everett JCT	1020	1230	1510
E8V	Alliston JCT	Alliston TS	1020	1230	1510
E8V	Alliston JCT	Alliston JCT	1020	1230	1510
E8V	Essa TS	Alliston JCT	1020	1230	1510
E8V	Everett JCT	Orangeville TS	1020	1180	1270
E8V	Everett JCT	Everett TS	1020	1230	1340
E9V	Alliston JCT	Everett JCT	1020	1230	1510
E9V	Alliston JCT	Alliston TS	1020	1230	1510
E9V	Alliston JCT	Alliston JCT	1020	1230	1510
E9V	Essa TS	Alliston JCT	1020	1230	1510
E9V	Everett JCT	Orangeville TS	1020	1230	1510
E9V	Everett JCT	Everett TS	1020	1230	1340
M6E	Bracebridge JCT	Bracebridge TS	1000	1000	1000
M6E	Bracebridge JCT	Muskoka TS	750	750	750
M6E	Cooper's Falls JCT	Orillia TS	760	760	760
M6E	Cooper's Falls JCT	Bracebridge JCT	750	750	750

Circuit Name	From	To	Continuous	LTE	STE
M6E	Midhurst TS	Essa TS	1020	1210	1310
M6E	Minden TS	Cooper's Falls JCT	760	760	760
M6E	Orillia TS	Midhurst TS	750	750	750
M7E	Bracebridge JCT	Muskoka TS	970	970	970
M7E	Cooper's Falls JCT	Orillia TS	750	750	750
M7E	Cooper's Falls JCT	Bracebridge JCT	970	970	970
M7E	Midhurst TS	Essa TS	1020	1230	1350
M7E	Minden TS	Cooper's Falls JCT	750	750	750
M7E	Orillia TS	Midhurst TS	970	970	970
M80B	Beaver JCT	Brown Hill TS	1020	1230	1340
M80B	Beaver JCT	Beaverton JCT	1020	1230	1510
M80B	Beaverton JCT	Beaver JCT	1020	1230	1390
M80B	Beaverton JCT	Lindsay TS	1020	1230	1510
M80B	Minden TS	Beaverton JCT	1020	1090	1130
M81B	Beaver JCT	Beaverton JCT	1020	1230	1510
M81B	Beaver JCT	Brown Hill TS	1020	1230	1340
M81B	Beaverton JCT	Lindsay TS	1020	1220	1330
M81B	Beaverton JCT	Beaver JCT	1020	1090	1130
M81B	Minden TS	Beaverton JCT	1020	1090	1130
S2S	Meaford TS	Stayner TS	720	870	940
S2S	Owen Sound TS	Meaford TS	720	870	1020

D.4 Credible Planning Events & Criteria

D.4.1 Studied Contingencies

Table below shows the contingencies assessed in the technical report.

Table 7 - Contingencies to be Assessed

Pre-contingency	Contingency[10]	Type	Mapping to TPL/ Directory 1 Event	Rating[11]	Maximum Allowable Load Loss
All in-service	None	N-0	P0	Continuous	None
All in-service	Single	N-1	P1, P2	LTE	150 MW by-configuration
All in-service	Double	N-2	P7, P4, P5	STE, reduced to LTE	150 MW lost by curtailment; 600 MW Total
Local Generation out-of-service	None	N-0	N/A	Continuous	None
Local Generation out-of-service	Single	N-1	P3	LTE	150 MW by-configuration; >0 MW lost by curtailment[12]; 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

[10] 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.

[11] 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.

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

The lists below show the specific single, common tower, and breaker failure contingencies to be studied. 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 and N-1-2 studies are very similar to the N-1 contingencies documented in below 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. For example, if the circuits have a capacitor, the capacitor is taken out of service for the contingency but not in an outage situation.

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

- E8V
- E9V
- E20S
- E21S
- E26
- E27
- E28
- E29
- M6E
- M7E
- M80B
- M81B
- D1M
- D2M
- D3M
- D4M
- Essa T3
- Essa T4

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

- D1M + D2M
- E8V + E9V
- E20S + E21S

- E26 + E27
- E28 + E29
- M6E + M7E
- M80B + M81B
- Essa AL26
- Essa AL6
- Essa AL8
- Essa HT4
- Essa HL7
- Essa HL9
- Essa HT3L9
- Essa HT3L6
- Essa L7L20
- Essa L8L20
- Essa T4L26
- Essa CB1[13]
- Essa CB2[7]
- Essa CB3[7]
- Minden AL1
- Minden AL2
- Minden AL3
- Minden AL4
- Minden L1L6
- Minden L2L7
- Minden L3L80
- Minden L4L81
- Minden HL6
- Minden HL7

[13] These are new circuit breakers to be installed at Essa TS following the completion of the Barrie Area Transmission Upgrade project. The name of this circuit breaker is subject to change and is located in Essa TS as per Figure 1 of the CAA 2016-580 Final Report.

- Minden HL80
- Minden HL81
- Holmur CSS L25L26
- Holmur CSS L25L27

D.4.2 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"),
- IESO Ontario Resource and Transmission Assessment Criteria ("ORTAC").

D.4.2.1 Supply Capacity Requirements

All elements in-service – No Contingency
No issues have been identified with all elements in-service with no contingency.

All elements in-service – Loss of Single Contingency
As per Table 7, transmission system loading for the loss of a single contingency should not exceed LTE ratings with all elements in-service pre-contingency. With all elements in service, the following was seen for loss of a single contingency:

- The 230 kV circuit M7E section from Essa TS to Midhurst TS exceeds the LTE rating for the loss of M6E circuit by 4% in 2040 and it is at 87% of its LTE rating in 2030.
- The 230 kV circuit M6E section from Essa TS to Midhurst TS exceeds the LTE rating for the loss of M7E circuit by 11% in 2040 and it is at 87% of its LTE rating in 2040.
- The 230 kV circuit M6E section from Minden TS to Cooper's Falls JCT is just above the LTE rating for loss of M7E in 2040 and 87% of its LTE rating in 2030.
- Essa T3 is shown to be at 100% of its LTE rating for the loss of Essa T4 in 2022, followed by 111% in 2030 and 130% in 2040.
- Essa T4 is shown to be at 100% of its LTE rating for the loss of Essa T3 in 2040. The loss of an Essa autotransformer will be further considered as part of a bulk planning study.

All elements in-service – Loss of Double Contingency
As per Table 7, transmission system loading for a double contingency should not exceed STE ratings immediately after the contingency with all elements in-service pre-contingency. The 230 kV circuit M6E section from Essa TS to Midhurst TS exceeds the STE rating by 1% in 2040 for the Essa HL7, Essa L7L20 or Minden L2L7 breaker failure contingencies. In 2030, the loading of M6E for these double contingencies are at 84% of STE rating.

Local Generation out-of-service – No Contingency

No issues have been identified with local generation out-of-service with no contingency.

Local Generation out-of-service – Loss of Single Contingency

For the loss of a single contingency with a local generation out-of-service, the LTE rating should not be exceeded. The following was seen with local generation out-of-service:

- With Des Joachims G5 - G8 or with Henvey Wind Inlet GS out-of-service, the 230 kV circuit M7E section from Essa TS to Midhurst TS exceeds the LTE rating for the loss of M6E circuit by 7% or 4% in 2040 (89% and 86% of LTE rating in 2030).

- With Des Joachims G5 - G8 or with Henvey Wind Inlet GS out-of-service, the 230 kV circuit M6E section from Essa TS to Midhurst TS exceeds its LTE rating for the loss of M7E circuit by 13% or 10% in 2040 (95% and 92% of LTE rating in 2030).

- With Henvey Wind Inlet GS out-of-service, the 230 kV circuit M6E section from Minden TS to Cooper's Falls JCT exceeds the LTE rating for the loss of M7E circuit by 1% in 2040 (88% of LTE rating in 2030).

- With Henvey Wind Inlet GS out-of-service, Essa T3 is at 3% over its LTE rating for the loss of Essa T4 in 2022. This value increases to 14% in 2030 and 32% in 2040. Essa T4 is at 1% over its LTE rating in 2040. Consistent with the finding above, this will be further considered as part of a bulk planning study.

- With Des Joachims 5-8 GS out-of-service Essa, T3 is at 1% over its LTE rating for the loss of Essa T4 in 2022. This value increases to 12% in 2030 and 32% in 2040. Essa T4 is at 1% over its LTE rating in 2040. Consistent with the finding above, this will be further considered as part of a bulk planning study.

Transmission element out-of-service – Loss of Single Contingency

As per Table 7, with a transmission element out-of-service pre-contingency, transmission system loadings for the loss of a single contingency can go up to STE if there are control actions (e.g. SPS, generator re-dispatch) that can be used to reduce it to LTE ratings within the allotted time. If no control actions exist in the area, then LTE ratings should not be exceeded for a single contingency. For this analysis, we assume that there are no control actions available in this area.

- With M7E out-of-service pre-contingency, the section of M6E between Minden TS to Cooper's Falls JCT is over its LTE rating by 4% for the loss of M81B in 2040 and by 33% for loss of an Essa autotransformer. The section of M6E between Essa TS to Midhurst TD is over 10% of its LTE rating for the loss of one DxM circuit in 2040.

- With M7E out-of-service pre-contingency, the section of M6E between Essa TS to Midhurst TS is at 10% over its LTE rating for the loss of either D1M, D3M or D4M in 2040.

- With either Essa T3 or T4 out pre-contingency, the section of M6E between Minden TS to Cooper's Falls JCT is over its LTE rating by 28% for the loss of the companion Essa 500/230 kV transformer in 2022 and 50% in 2030.
- With M7E out-of-service pre-contingency, the section of M6E between Minden TS to Cooper's Falls JCT is over its LTE rating by 3% for the loss of Essa T3 in 2022. This increases to 17% in 2030 and 33% in 2040. The results are similar for the loss of Essa T4.

D.4.2.2 Step-Down Station Capacity Requirements

As shown in Table 8, there are step-down station capacity needs identified in Barrie TS, Everett TS and Waubaushene TS.

Table 8 – Step-down Station Summer Capacity Needs

Station	Cont. Rating (MW)	LTR Rating (MW)	2022 (MW)	2030 (MW)	2040 (MW)
Alliston TS	175.0	175.0	136.1	159.5	184.3
Barrie TS	172.8	172.8	105.3	225.7	254.5
Beaverton TS	193.0	193.0	68.6	71.5	86.6
Bracebridge TS	75.0	75.0	27.4	27.6	29.2
Everett TS	86.0	86.0	83.1	94.8	167.9
Lindsay TS	161.0	161.0	84.2	89.3	104.3
Meaford TS	52.0	52.0	33.4	34.2	39.2
Midhurst TS	311.0	311.0	275.0	284.7	339.1
Minden TS	52.0	52.0	44.3	45.8	52.8
Muskoka TS	169.0	169.0	113.2	124.6	136.5
Orangeville TS	194.0	194.0	139.3	160.4	189.3
Orillia TS	154.0	154.0	105.0	119.9	134.6

Station	Cont. Rating (MW)	LTR Rating (MW)	2022 (MW)	2030 (MW)	2040 (MW)
Parry Sound TS	102.0	102.0	44.8	53.8	58.2
Stayner TS	181.0	181.0	129.1	140.3	168.4
Wallace TS	49.0	49.0	35.9	36.5	38.5
Waubaushene TS	94.0	94.0	89.9	98.6	116.4

Table 9 – Step-down Station Winter Capacity Needs

Station	Cont. Rating (MW)	LTR Rating (MW)	2022 (MW)	2030 (MW)	2040 (MW)
Alliston TS	190.0	190.0	114.7	136.9	158.0
Barrie TS	194.4	194.4	80.8	179.5	201.4
Beaverton TS	213	213	77.0	80.5	88.1
Bracebridge TS	75.0	75.0	34.1	34.6	36.4
Everett TS	86.0	86.0	58.1	66.3	136.0
Lindsay TS	182.0	182.0	92.2	98.2	106.9
Meaford TS	59.0	59.0	43.5	44.8	54.4
Midhurst TS	355.0	355.0	202.2	210.7	244.7
Minden TS	64.0	64.0	54.5	56.7	63.8
Muskoka TS	199.0	199.0	145.6	158.4	167.8
Orangeville TS	226.0	226.0	119.8	135.0	162.8
Orillia TS	175.0	175.0	107.8	123.3	132.9

Station	Cont. Rating (MW)	LTR Rating (MW)	2022 (MW)	2030 (MW)	2040 (MW)
Parry Sound TS	119.9	119.9	59.2	69.1	74.1
Stayner TS	202.0	202.0	135.0	145.1	175.1
Wallace TS	54.0	54.0	38.2	39.1	41.1
Waubaushene TS	104.0	104.0	74.4	80.5	88.9

Barrie TS

With the Barrie Area Transmission Upgrade (BATU) project underway, Barrie TS will have a 10-day LTR of 172.8 MW. The summer demand forecast will exceed the 10-day LTR by 2027.

Everett TS

Everett TS has a summer 10-day LTR of 86 MW. The summer demand forecast starts exceeding the 10-day LTR in 2025 and is exceeded by 82 MW in 2040.

Waubaushene TS

Waubaushene TS has a summer 10-day LTR of 94 MW. The summer demand forecast starts exceeding the 10-day LTR in 2027 and is exceeded by 22 MW in 2040.

D.4.2.3 Load Security

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

No load security need has been identified in the planning timeframe. For single contingencies, there is no loss of load greater than 150 MW by configuration and for double contingencies, there is no loss of load greater than 600 MW in the 20-year study period.

D.4.2.4 Load Restoration

No load restoration issues identified for the region.

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