Niagara Integrated Regional Resource Plan

Appendices
December 22, 2022

Connecting Today.
Powering Tomorrow.

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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. 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.

The regional planning process begins with a Needs Assessment stage 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 Integrated Regional Resource Plan ("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 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.

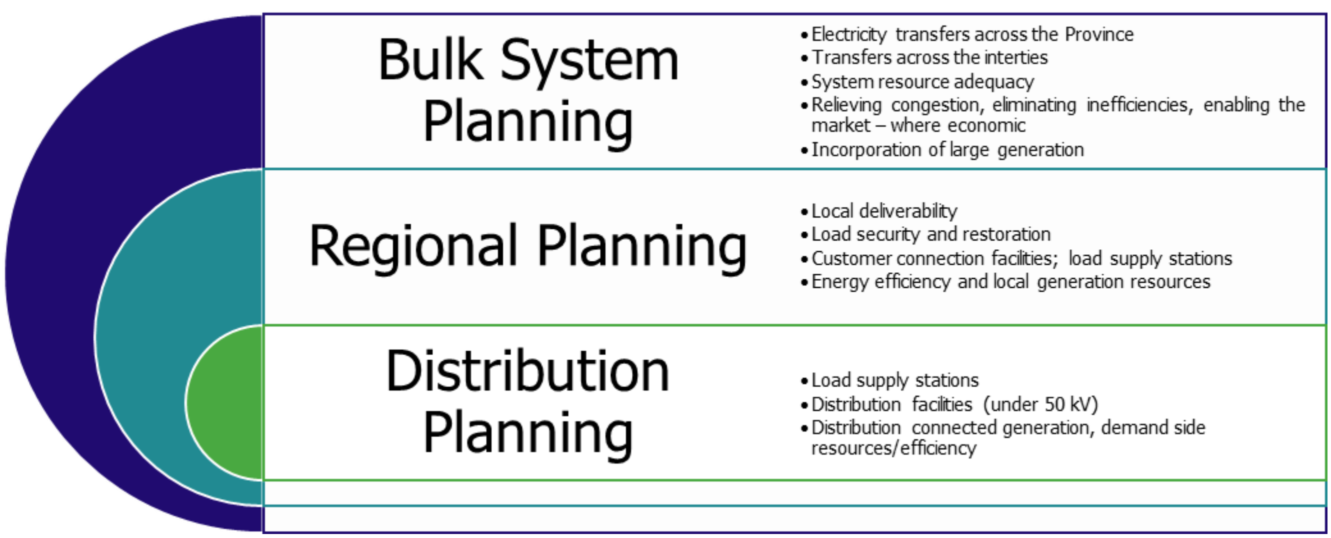
The final Needs Assessment Reports, Scoping Assessment Outcome Reports, IRRPs, and RIPs are posted on the IESO's and the relevant transmitter's websites, and may be referenced and submitted to the OEB as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. 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, conservation and demand management ("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. Peak Demand Forecast

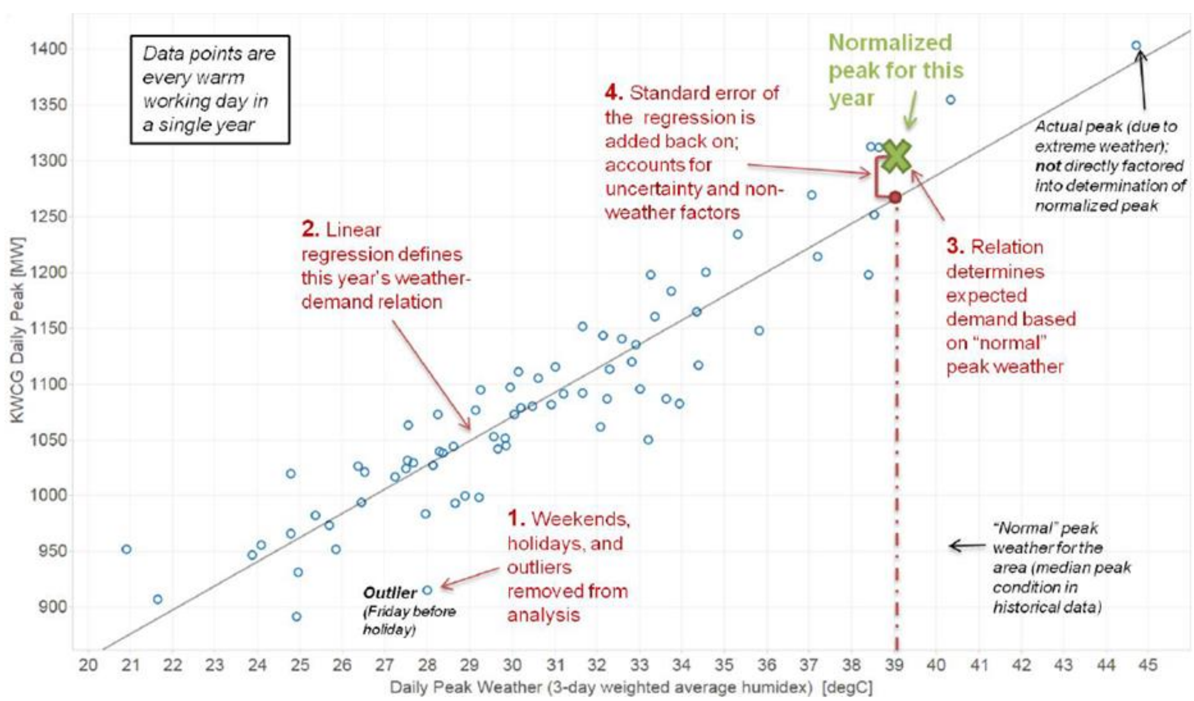
Appendix B describes the methodologies used to develop the demand forecast (peak and duration) for the Niagara Region IRRP studies. Forward-looking estimates of electricity demand were provided by each of the participating LDCs and informed by the forecast base year and starting point provided by the IESO. The sections that follow describe the weather correction methodology, the approaches and methods used by each LDC to forecast demand in their respective service area, the conservation and distributed generation ("DG") assumptions, hourly forecasting methodology, and high forecast scenario 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., 2021 for the Niagara Region 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 station-level 2021 median weather peak was provided to each LDC. This data was used as a starting point from which the LDCs could develop 20-year gross median demand forecasts using their preferred methodologies (described in the next sections).

Once the 20-year, median peak demand forecasts were submitted to the IESO, the normal weather forecast was adjusted to reflect the impact of extreme weather conditions on electricity demand, and forecast demand savings from CDM and contracted DG were accounted for. The studies used to assess the adequacy and reliability of the electric power system are generally required to be based on extreme weather demand – typically the expected demand under the hottest weather conditions that can be reasonably expected to occur. Peaks that occur during extreme weather (i.e., summer heat waves in southern Ontario) are generally when the electricity system infrastructure is most stressed.

B.2 Alectra Utilities Forecast Methodology

The City of St Catharines is supplied by four 13.8 kV Hydro One stations: Bunting TS, Carlton TS, Glendale TS, and Vansickle TS. The city is seeing intensification growth in core areas throughout with attention in the downtown locations. Greenfield areas both east and west of the city are seeing residential and commercial development, with the west end forecast to have greater development in the future.

The Alectra Utilities long-term load forecast provides an indication as to where and how much the load increases are occurring. An increase in the peak demand is normally the biggest factor in driving the requirement for reinforcement of the system. 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 Conservation Initiative ("ICI") building 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 Ontario government, and regional/municipal government.

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 projection were used to develop long-term employment forecast potentially categorized by the sector, industry and service types.

Housing Activities: Number of housing completions, mix of housing completions, vacancy rate and building permit activities in the Region and Municipal boundaries and residential developments plan were reviewed for long-term capacity need forecast. Plans of subdivision 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 for the region.

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 scenario for system planning purposes to contemplate the impact of extreme weather (i.e., high temperatures) on peak demand. (The 1 in 2 forecast was used to develop the gross IRRP median weather forecast. This was subsequently adjusted for extreme weather.)

Other Factors

The other contributing factors to long-term load projections were CDM, DG 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 actual 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.

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 produced a comprehensive analysis and study using the available information on electric vehicle adoption and evaluates their impact 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.

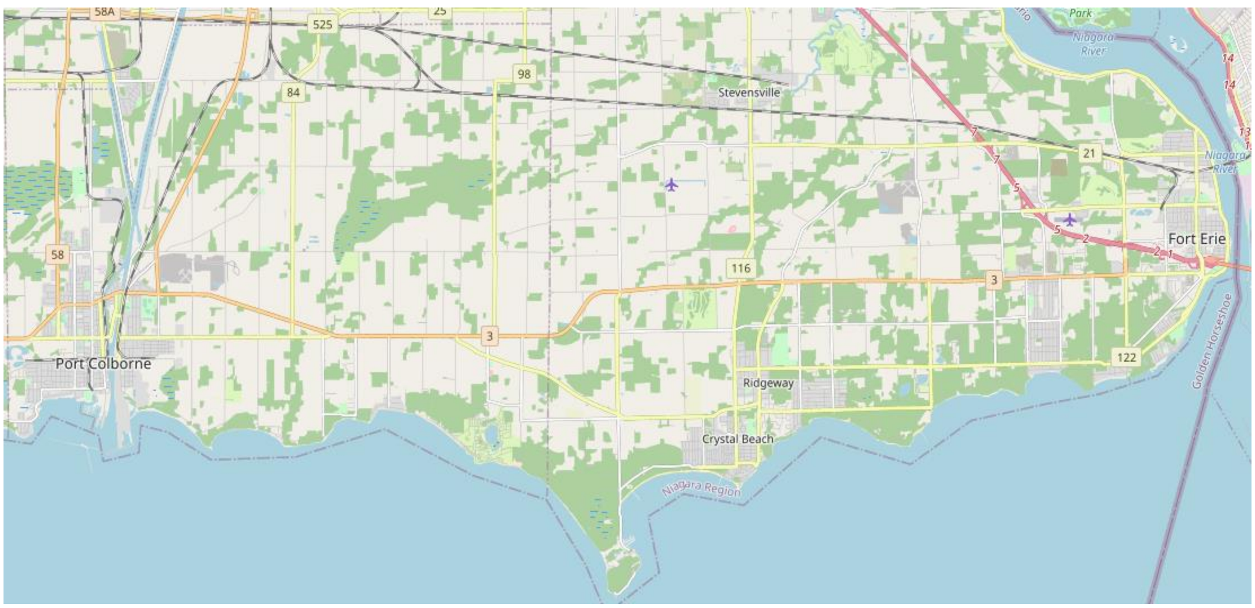
Conclusion

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.3 Canadian Niagara Power Inc. Forecast Methodology

Canadian Niagara Power is a Fortis Ontario Company and services hydro to the Town of Fort Erie and City of Port Colborne. The City of Port Colborne customers are fed from Port Colborne TS which is owned by Hydro One, and Town of Fort Erie customers are fed from Canadian Niagara Power's owned Station 17 TS and Station 18 TS. The map below illustrates the entire service area for Canadian Niagara Power.

Figure 3 | Canadian Niagara Power's Service Area



Canadian Niagara Power has multiple voltages in the service territory between City of Port Colborne and Town of Fort Erie when it took ownership of these service areas. There are no load transfers with the neighbouring utilities. Currently, Canadian Niagara Power has around 26,000 customers and majority of the customers are residential; however, there has been a slow increase in the commercial and industrial customers.

Canadian Niagara Power's distribution network makes of 80% overhead and other 20% underground between primary and secondary conductors.

Factors Affect Electricity Demand

Canadian Niagara Power is seeing mainly residential load growth and slight amounts of commercial and industrial load growth. Its electrical high peak is in the summer season, and the CDM and distribution energy resource have no substantial affect on the distribution system due to low increase or no demand. However, there are a few small net-metering and battery storage load displacement projects on their distribution system.

Forecast Methodology and Assumptions

The current load forecast is implemented on basis of Canadian Niagara Power's historical demand, and it includes the recent changes of growth after the COVID-19 affect of residential immigration from Greater Toronto Area to their territory. As mentioned, the CDM and distribution energy resource are insignificant to the Canadian Niagara Power forecast load growth in their territory at this moment.

Canadian Niagara Power is anticipating linear growth - mainly residential and commercial, including small industrial load growth. The other load growth assumptions such as electric vehicle and battery storage load displacement shall be included, as these technologies mature in near future.

B.4 Grimsby Power Inc. Forecast Methodology

Below is the methodology used to determine the planning load forecasts for Grimsby Power load on Beamsville TS and Niagara West TS.

Methodology

The load forecast is a combination of specific point loads and assumed growth in percent. Point loads include known residential, commercial, and industrial developments. Both assumed growth and point loads were added to the 2022 summer peak load to determine the forecast.

The first five years of the forecast uses a combination of percentage growth and point loads. The percentage growth is lower for the first five years since development specific information is available. After five years the forecast includes percentage growth only.

High and Low Growth

Both a Low Growth and a High Growth forecast were developed to provide a range of potential outcomes.

The High Growth forecast assumes all proposed point loads for new developments are connected, plus a percentage of incremental load growth. This is the forecast provided to the IRRP study.

The Low Growth forecast assumes all proposed point load developments are deferred and not connected, zero growth for the first five years, followed by low incremental growth.

2022 Summer Peak Load

Summer peak loads were retrieved from revenue metering data.

Incremental Growth

This growth category includes both incremental increase of existing customer loads and infill developments. The forecast included both Low Growth and High Growth scenarios and the annual percentages are shown in Table 1.

Table 1 | Grimsby Power Forecast Growth Assumptions

Load Growth	Years 1-5	Years 6 +
Low	0.0%	1.0%
High	1.0%	3.0%

Residential Developments

Residential developments were modelled using the location and number of units for the development.

The location determined which feeder and which station the load would be supplied from. An estimated demand per unit was multiplied by number of units to determine the total demand load.

Condominium developments were assumed to be occupied over a 3-year period from initial connection, with load from one third of the units added in each of the three years. Subdivision developments were spread over a 4-year period.

Commercial/Industrial Developments

Commercial and industrial developments were modelled using the forecast demand load and year of connection provided by the developer. The year of connection was estimated in some cases, based on the current status of the project.

Two large potential developments have significant impact on the load forecast. One is an industrial development of 6.1 MW that was started but not completed. The other is a potential large commercial development with a projected load of 6.0 MW. These two project loads have been included in Grimsby Power's High Load Forecast only.

B.5 Hydro One Distribution Forecast Methodology

Hydro One Distribution services the areas of Niagara region that are not serviced by other LDCs. It supplies power through various stations in the study area, including Allanburg TS, Crowland TS, Dunnville TS, Murray TS, Niagara West MTS, and Thorold TS. Hydro One also supplies load to its customers through Beamsville TS and Niagara West MTS as an embedded LDC.

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

For the Niagara IRRP forecast, Hydro One Distribution used the weather-corrected peak demand levels for the station serving Hydro One customers. From the established baseline year, a growth rate (%) was applied to station demand level to provide forecast values within the study timeframe.

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

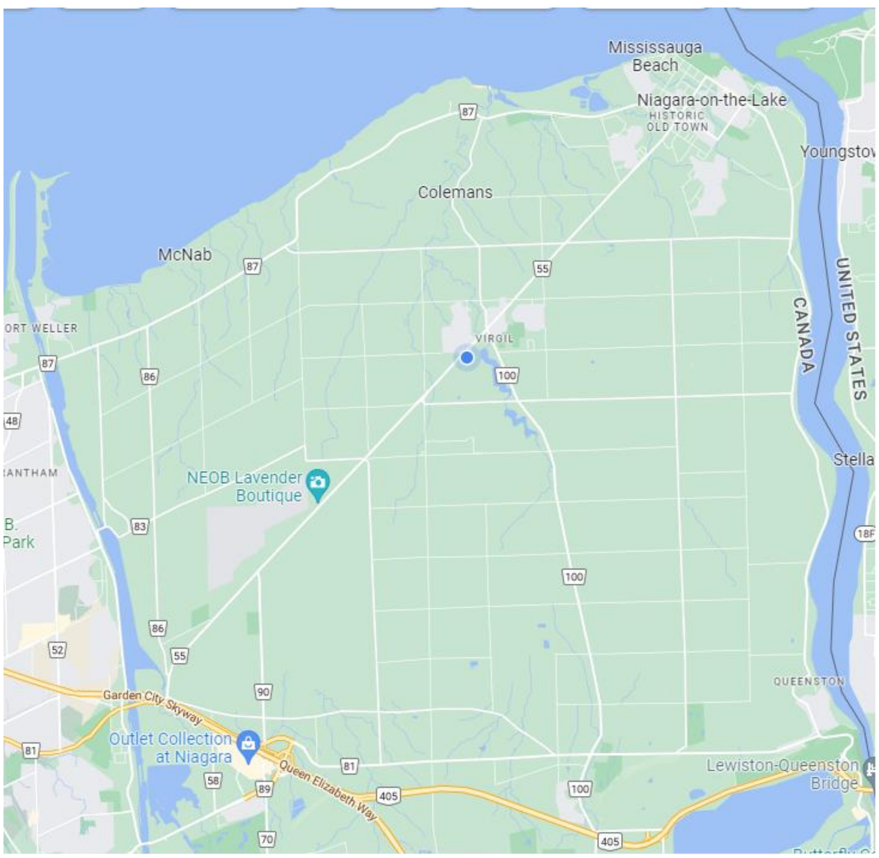
Where possible, detailed information about load growth, based on local knowledge and or municipal/provincial plans, was used to augment the forecast values within the study period.

B.6 Niagara-on-the-Lake Hydro Inc. Forecast Methodology

Gross Forecast Methodology and Assumptions

Niagara-on-the-Lake ("NOTL") Hydro is wholly owned by The Town of Niagara-on-the-Lake, and serves the town's citizens and businesses exclusively. NOTL Hydro's service area is bordered by the Welland Canal, the Niagara River, Lake Ontario, and areas near the QEW and Hwy. 405. The prevailing industry is tourism, vineyards, and wineries. The customer base is augmented by a mix of residential and small commercial entities.

Figure 4 | NOTL Hydro's Service Area



Factors that Affect Electricity Demand

NOTL Hydro experiences consistently low load growth year over year due to the largely rural zoning of the service area. Niagara-on-the-Lake boasts high per capita customer-owned solar generation installations that are considered as part of the load forecast calculations.

Forecast Methodology and Assumptions

NOTL Hydro consults town and region staff regarding development plans, and bases the electrical load forecast on known existing connection changes and area development plans. For example, the forecast incorporates the loss of one large customer, and includes the projected load of proposed new subdivisions, staged over time. Other factors applied to the forecast include load growth trends in pre-pandemic times leading up to 2019, and projected weather related trends.

B.7 Niagara Peninsula Energy Inc. Forecast Methodology

Niagara Peninsula Energy Inc. ("NPEI") owns and operates the electricity distribution system which serves the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln, and a portion of Fonthill in the Town of Pelham. NPEI's total service area is approximately 827 square km, located in the Niagara Region.

The Western portion of NPEI's service territory is substantially rural and includes the Township of West Lincoln and the Town of Lincoln. The distribution system covers the limits of Lincoln and West Lincoln townships. Electricity is supplied to customers in these areas via the following substations: Vineland DS, Beamsville TS, and Niagara West MTS.

The Eastern portion of NPEI's service territory consists of the City of Niagara Falls and has a significant urban component with a high traffic tourism core. The Southern and Western portions of the City of Niagara Falls are primarily rural. Electricity is supplied to customers in the city via the following substations: Murray TS, Stanley TS, Kalar TS.

At the center of NPEI's service territory is the village of Fonthill which is a portion of the Town of Pelham. The distribution system covers a portion of the urban limits of Fonthill only. Electricity is supplied to customers in these areas via the following substations: Allanburg TS.

NPEI's overall load forecast was based on peak demand growth of 1% per annum from 2022 - 2041. These figures considered historical growth and available population growth forecasts. Where specific pockets of increased development are anticipated, the projected growth forecast was adjusted accordingly.

The starting point for the load forecast was the coincident peak demand data by TS for the most recent year of actuals (2020), which NPEI adjusted to account for normal operating conditions. A growth rate (%) was applied to the most recent year of actuals to provide forecast values, at each station, within the study time frame.

Kalar TS Load Forecast

1. Historical peak MW are based on NPEI feeder data and are not corrected for weather normalization (Historical Weather-Corrected Gross Station Demand at Coincidental Regional Peak Hours (MW)).
2. Planned development is based on known developments in the South Niagara area which include the new Niagara South hospital, a new water treatment plant and a proposed 2,000 lot subdivision all supplied from this station. Anticipated load years are estimated based on projected construction schedules.
3. At the time of this load forecast NPEI is unaware of any proposed behind-the-meter generation projects within the load forecast area.
4. NPEI has estimated an annual growth factor of 2.0% from 2022 to 2030 for this station. This higher than normal factor is due to the expected growth around the new South Niagara Hospital and is based on load growth experienced in other jurisdictions after a hospital is place into service. From 2031 to 2041 the estimated growth is expected to level off and as such NPEI lower the growth factor to 1.0% for the remainder of the forecast period.
5. Weather factors beyond IESO information have not been considered in this forecast.

Vineland DS Load Forecast

1. Historical peak MW are based on NPEI feeder data and are not corrected for weather normalization (Historical Weather-Corrected Gross Station Demand at Coincidental Regional Peak Hours (MW)).
2. Planned development is based on known development in Prudhomme’s Landing area supplied by this station. Anticipated load years are estimated based on projected construction schedule.
3. At the time of this load forecast NPEI is unaware of any proposed behind-the-meter generation projects within the load forecast area.
4. NPEI has estimated an annual growth factor of 1.0% from 2022 to 2041. The growth factor shown in the chart per year is based on the 2021 peak MW and is calculated as 20.3MW * 0.01 = 0.2MW in 2022. Each subsequent year is based on the prior year. Thus 2023's annual growth is based on 2022's forecasted peak.
5. Weather factors beyond IESO information have not been considered in this forecast.

Beamsville TS Load Forecast

1. Historical peak MW are based on NPEI feeder data and are not corrected for weather normalization (Historical Weather-Corrected Gross Station Demand at Coincidental Regional Peak Hours (MW)).
2. An application for a 6MW load has recently been approved has been added to the 2022 peak.
3. A load transfer from Beamsville TS to Niagara West TS has been proposed and is currently under review. If approved will need to be included.
4. At the time of this load forecast NPEI is unaware of any proposed behind-the-meter generation projects within the load forecast area.

5. NPEI has estimated as annual growth factor of 1.0% from 2022 to 2041. The growth factor shown in the chart per year is based on the 2021 peak MW. Each subsequent year is based on the prior year.
6. Weather factors beyond IESO information have not been considered in this forecast.

Niagara West TS Load Forecast

1. Historical peak MW are based on NPEI feeder data and are not corrected for weather normalization (Historical Weather-Corrected Gross Station Demand at Coincidental Regional Peak Hours (MW)).
2. A load transfer from Beamsville TS to Niagara West TS has been proposed and is currently under review. If approved will need to be included.
3. At the time of this load forecast NPEI is unaware of any proposed behind-the-meter generation projects within the load forecast area.
4. NPEI has estimated as annual growth factor of 1.0% from 2022 to 2041. The growth factor shown in the chart per year is based on the 2021 peak MW. Each subsequent year is based on the prior year.
5. Weather factors beyond IESO information have not been considered in this forecast.

Allanburg TS, Murray TS, and Stanley TS Load Forecast

1. Historical peak MW are based on NPEI feeder data and are not corrected for weather normalization (Historical Weather-Corrected Gross Station Demand at Coincidental Regional Peak Hours (MW)).
2. At the time of this forecast NPEI is unaware of any major planned developments within the load forecast area.
3. At the time of this load forecast NPEI is unaware of any proposed behind-the-meter generation projects within the load forecast area.
4. NPEI has estimated as annual growth factor of 1.0% from 2022 to 2041. The growth factor shown in the chart per year is based on the 2021 peak MW. Each subsequent year is based on the prior year.
5. Weather factors beyond IESO information have not been considered in this forecast.

B.8 Welland Hydro Electric System Corp. Forecast Methodology

Welland Hydro Electric System Corp. ("WHESC") owns and operates the electricity distribution system which serves the City of Welland. WHESC's total service area is 81 square km, located in the Niagara Region. WHESC supplies power through a single transformer station, Crowland TS.

WHESC currently serves approximately 25,000 customers. The City of Welland has experienced increased residential and small commercial growth in recent years. The increased level of growth is expected to continue with re-development activities and expansion of the urban boundary within the City.

Figure 5 | Welland Hydro's Service Territory

WHESC load forecasting considers municipal and regional planning estimates of population growth. WHESC's overall load forecast was based on:

1. Load additions associated with studies from developments currently underway
2. A peak demand growth of 2% per annum for the period 2023 through 2031
3. A peak demand growth of 1% per annum was estimated for 2032 to 2041

These figures are based on recent historical growth and available population growth forecasts from the City of Welland and the Niagara Region.

B.9 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 Niagara IRRP forecast are consistent with the energy efficiency assumptions in the IESO's 2021 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 Niagara IESO transmission zone and then allocated to the Niagara Region. This section describes the process and methodology used to estimate energy efficiency savings for the Niagara Region and provides more detail on how the savings for the two categories were developed.

B.9.1. 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 Niagara 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, 2021 was used as the base year. New peak demand savings from codes and standards were estimated from 2022 to 2041. 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 2041, the residential sector in the region is expected to see about 9% peak demand savings through codes and standards. The same is done for the commercial sector, which will see about 4.5% peak-demand savings through codes and standards by 2041. 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.9.2. 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 assumed continuation of provincial programs beyond 2024 at savings levels consistent with the current framework adjusted for gross demand growth.[1] A top down approach was used to estimate the peak demand reduction due to the delivery of these programs, from the province, to the Niagara 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 Niagara zone. They were then applied to the sectoral gross peak forecast of each station in the region. By 2041, the residential sector in the region is expected to see about 0.4% peak demand savings through programs, while commercial sector and industrial sector will see about 8% and 3% peak reduction respectively.

B.9.3. 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. The resulting forecast savings were applied to gross demand to determine net peak demand for further planning analyses.

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[1] On October 4, 2022 the Minister of Energy directed the IESO to expand the 2021-2024 CDM Framework, increasing savings targets. Due to the timing of this directive, the Niagara IRRP's CDM assumptions reflect the 2021-2024 CDM Framework's original savings levels.

See Table 2 in the Niagara IRRP Appendix Excel file for the CDM (Codes and Standards + Energy Efficiency) Forecast.

B.10 Installed Distributed Generation and Contribution Factor Assumptions

See Table 3 in the Niagara IRRP Appendix Excel file for the Distributed Generation Contribution Factor Assumptions.

See Table 4 in the Niagara IRRP Appendix Excel file for the Installed Distributed Generation Output Assumptions.

B.11 Final Peak Forecast by Station

After taking the median weather forecast provided by LDCs and applying the CDM and DG assumptions above, forecasts were adjusted to extreme weather. The final peak demand forecasts, by station, are provided in Table 5 in the Niagara IRRP Appendix Excel file.

B.12 High Forecast Scenario

See Table 6 in the Niagara IRRP Appendix Excel file for the High Forecast Scenario.

Appendix C. IRRP Screening Mechanism

The screening mechanism is a relatively new approach at the time of this Niagara IRRP. For the latest information on Regional Planning process improvements – specifically those related to non-wires – and the most up-to-date screening criteria, refer to the IESO's Distributed Energy Resources Roadmap webpage.

Table 7 | Screening Step 1: Type of Need

Option	Supply Capacity Need	Station Capacity Need	Load Security Need
Transmission-connected generation or storage	Yes	No	No
Energy efficiency	Yes	Yes	No
Distributed generation	Yes	Yes	No
Demand response	Yes	Yes	No

Table 8 | Screening Step 2: Narrow Down Options Based on High-Level Need Traits

Option	Need timing	Size of need	Need's coincidence with system peak
Transmission-connected generation or storage	>3 years	Unlimited	Generation can likely provide system value during provincial peaks even if local need is not coincident
Energy efficiency (i.e., CDM)	>4 years	<2% of load forecast in each year	Energy efficiency can target needs that are not coincident with system peaks, but provides the greatest value when reducing provincial system peaks
Distributed generation	>4 years	<DG connection space (see **Error! Not a valid bookmark self-reference.**)	Generation can likely provide system value during provincial peaks even if local need is not coincident
Demand response	>2 years	Proportional to historically offered in zonal auction	DR can target needs that are not coincident with system peaks, but the Capacity Auction acquires resources designed to meet system peaks

Table 9 | Estimated DG Connection Space[2]

Station	Existing Installed Contracted DG (MW)	Short Circuit Allowance (MVA)	Thermal Limit Allowance (MW)
Beamsville TS (BY)	2 (solar)	365	29
Crowland TS (QY)	13 (solar), 10 (water)	62	29
Kalar MTS	1 (landfill gas)	To be determined	To be determined
Vineland DS (T1)	0.3 (biomass), 0.3 (solar)	415	12
Vineland DS (T2)	See above	419	14

[2] Actual connection feasibility would be subject to further studies. Resources to estimate DG connection capacity can be found on the Hydro One website. For up to date information, please contact local distribution companies.

Appendix D. Hourly Demand Forecast

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[3]); and
- Economic factors (employment data[4]).

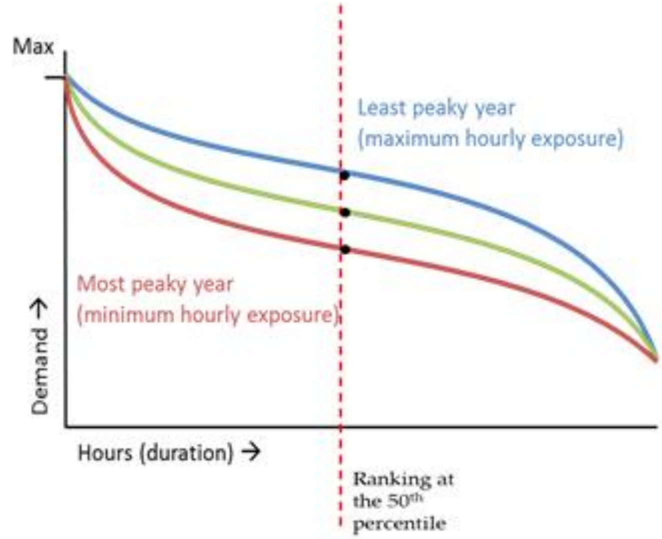
Model diagnostics (training mean absolute error, testing mean absolute error) were used to gauge the effectiveness of the selected predictor variables and to avoid an over-fitted model. While future values for calendar, demographic, and economic variables were incorporated in a relatively straightforward 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 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 465 forecasts were ranked in ascending order based on their median energy values. Load duration curves which illustrate this ranking can be seen in Figure 6.

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

Figure 6 | 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 Niagara IRRP, the median profiles were scaled to their respective maximums from the peak demand forecast.

Sections D.2 and D.3 contain additional examples of the forecast hourly profiles for Beamsville TS and Crowland TS. Heat maps are also provided to illustrate some of the station capacity need characteristics.

D.2 Beamsville TS Capacity Need

See Table 10 in the Niagara IRRP Appendix Excel file for the station's forecast hourly load profile and need in 2041.

Figure 7 | Heat Map Showing Possible Frequency of Beamsville TS Capacity Need in 2041, by MW and Month

MW Range	**40+**	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	36	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	31	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%
	27	0%	0%	0%	0%	0%	0%	2%	2%	0%	0%	0%	0%
	22	0%	0%	0%	0%	1%	1%	4%	4%	0%	0%	0%	0%
	18	0%	0%	0%	0%	1%	2%	7%	6%	1%	0%	0%	0%
	13	1%	0%	0%	0%	3%	4%	9%	8%	2%	0%	0%	1%
	9	2%	1%	0%	0%	5%	6%	11%	10%	4%	3%	1%	2%
	4	5%	4%	2%	1%	7%	8%	12%	12%	7%	5%	2%	5%
	0	9%	6%	4%	3%	10%	11%	13%	13%	10%	9%	5%	8%
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
		Month											

Figure 8 | Heat Map Showing Possible Frequency of Beamsville TS Capacity Need in 2041, by MW and Hour of the Day

MW Range	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
40+	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
36	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
31	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%
27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	2%	2%	1%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	2%	2%	2%	2%	1%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	1%	2%	2%	2%	1%	1%	2%	2%	2%	2%	3%	4%	2%	1%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	3%	5%	4%	2%	2%	2%	2%	2%	2%	3%	5%	7%	3%	2%	1%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	6%	7%	6%	5%	3%	3%	3%	3%	3%	5%	7%	8%	6%	3%	2%	1%	0%	0%
0	0%	0%	0%	0%	0%	2%	8%	8%	8%	7%	5%	5%	5%	5%	5%	7%	8%	9%	8%	6%	2%	2%	1%	0%
	Hour																							

Each cell in the heat map indicates the expected frequency of a load level at Beamsville TS, according to the month or hour. For instance, it is estimated that in roughly 1% of total hours in 2041, loading at Beamsville TS exceeds 31 MW and occurs in July, as indicated in Figure 7. Conversely, load levels are estimated to infrequently exceed 9 MW in shoulder season months such as March and April. From an hourly perspective (Figure 8), a sustained need is estimated across day hours (roughly 6 AM – 11 PM). High magnitude needs greater than for instance, 36 MW, will likely occur during early evening hours like 5 PM – 6 PM during the summer.

D.3 Crowland TS Capacity Need

See Table 11 in the Niagara IRRP Appendix Excel file for the station's forecast hourly load profile and need in 2041.

Figure 9 | Heat Map Showing Possible Frequency of Crowland TS Capacity Need in 2041, by MW and Month

MW Range	1	2	3	4	5	6	7	8	9	10	11	12
22+	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	8%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	12%	1%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	20%	1%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	28%	3%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	2%	41%	4%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	7%	55%	9%	1%	0%	0%	0%
0	0%	0%	0%	0%	0%	8%	74%	16%	2%	0%	0%	0%
	Month											

Figure 10 | Heat Map Showing Possible Frequency of Crowland TS Capacity Need in 2041, by MW and Hour of the Day

MW Range	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
22+	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	3%	1%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	5%	3%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	1%	3%	5%	7%	3%	1%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	3%	4%	7%	8%	6%	1%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	3%	6%	10%	13%	9%	3%	1%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	3%	1%	4%	9%	16%	19%	12%	4%	1%	0%	0%	0%
0	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	3%	3%	1%	7%	14%	20%	22%	19%	6%	2%	1%	0%	0%
	Hour																							

An additional sensitivity was conducted for the non-wires portfolio of options for the Crowland TS capacity need. After combining the uncommitted achievable CDM hourly profiles for Crowland TS with the station limit and its 465 potential hourly forecasts, there was a range of need profiles. These profiles indicated that to address 90% of the need profiles, the battery storage option for Crowland TS would need to be sized to be a 12.7 MW, 46.7 MWh facility. To address 95% and 100% of the need profiles, the battery storage would need to be 13.1 MW, 49.2 MWh and 14.2 MW, 56.2 MWh, respectively.

Typically, as described earlier, the median profile is selected for the purposes of the IRRP non-wires options analysis. Conducting this additional sensitivity revealed that a more probabilistic approach to the Crowland TS storage option sizing could increase the NPV estimate range up to $25M - $61M, but not ultimately impact this IRRP's decision-making and recommendations.

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 complement 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 OEB completed the first integrated electricity and natural gas achievable potential study in Ontario ("2019 APS"). The main objective of the APS was to identify and quantify energy savings (electricity and natural gas) potential, greenhouse gas emission reductions and associated costs from demand side resources for the period from 2019-2038 under different scenarios. This achievable potential modeling is used to inform:

- Future energy efficiency policy and/or frameworks;
- Program design and implementation; and
- Assessments of CDM non-wires potential in regional planning.

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.

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, were netted out and the remaining uncommitted achievable savings potential is identified. 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 Niagara region.

E.1 Incremental Energy for the Niagara Region

Based on the 2019 APS maximum achievable savings potential forecast, it is estimated that energy efficiency has the potential to reduce demand by approximately 1% per year on average in the Niagara transmission zone. In the near-term, a portion of these achievable savings opportunities are captured by the 2021-2024 CDM Framework and Federal energy efficiency programs. Overtime, new opportunities emerge with savings potential available across all sectors in this zone. The figures below illustrate the total maximum achievable savings potential in the Niagara zone according to segmentation (residential, commercial, and industrial).

Figure 11 | Cumulative Maximum Achievable CDM in Niagara as Share of Consumption

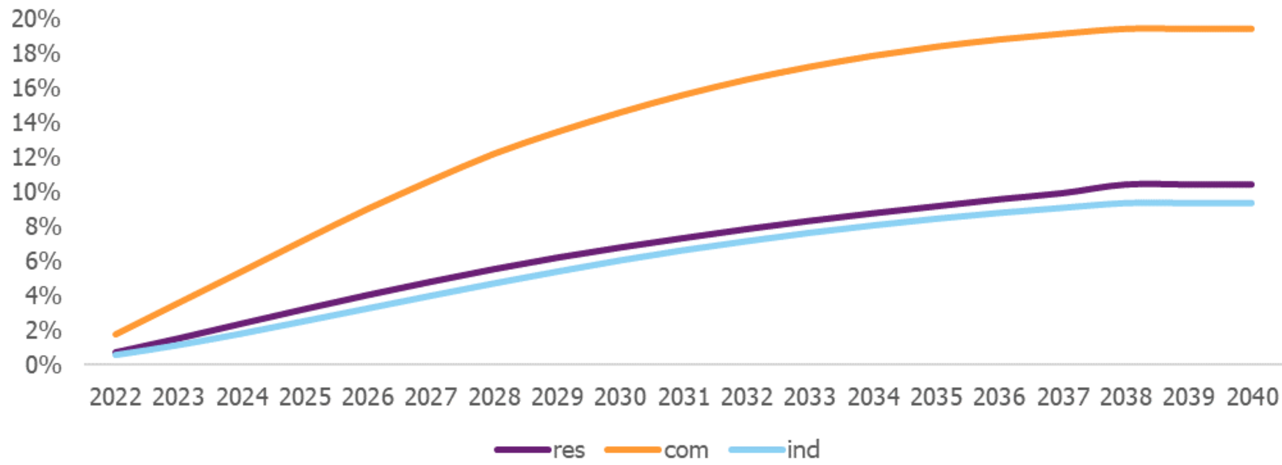
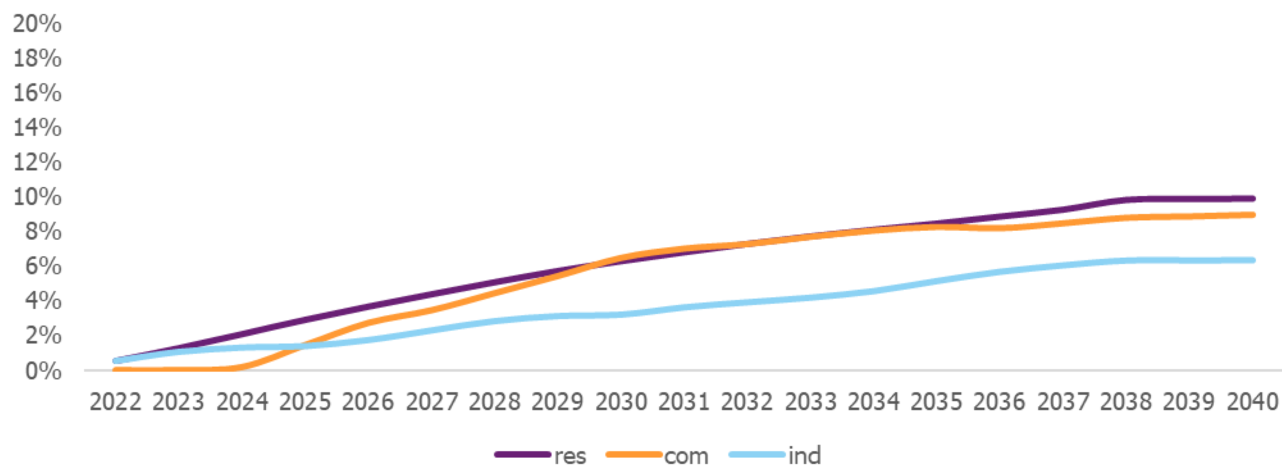
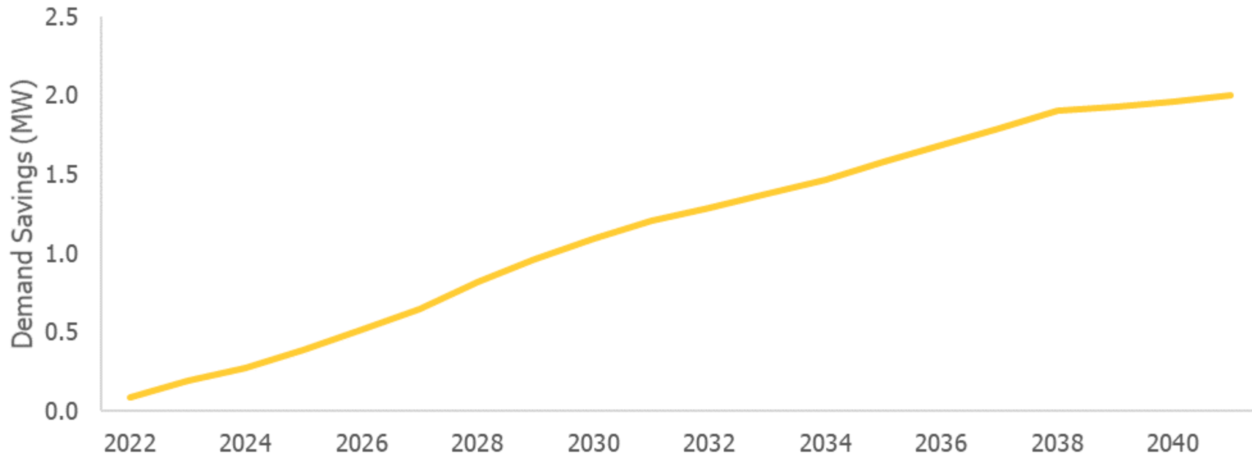


Figure 12 | Cumulative Maximum Achievable CDM in Niagara as Share of Net Committed Savings



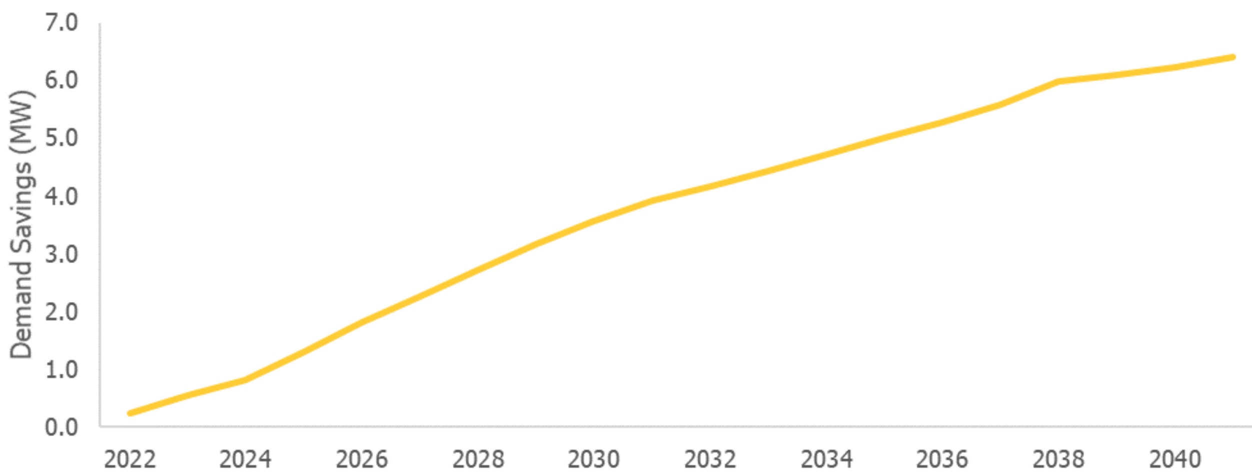
Applying these rates of uncommitted savings potential to the demand forecasts for Vineland DS, indicates that about 2 MW of CDM savings are available among customers connected to this station in 2041. The estimated cost to deliver these savings is $6.4 million dollars over the forecast period based on APS cost assumptions.

Figure 13 | Uncommitted CDM Potential at Vineland DS



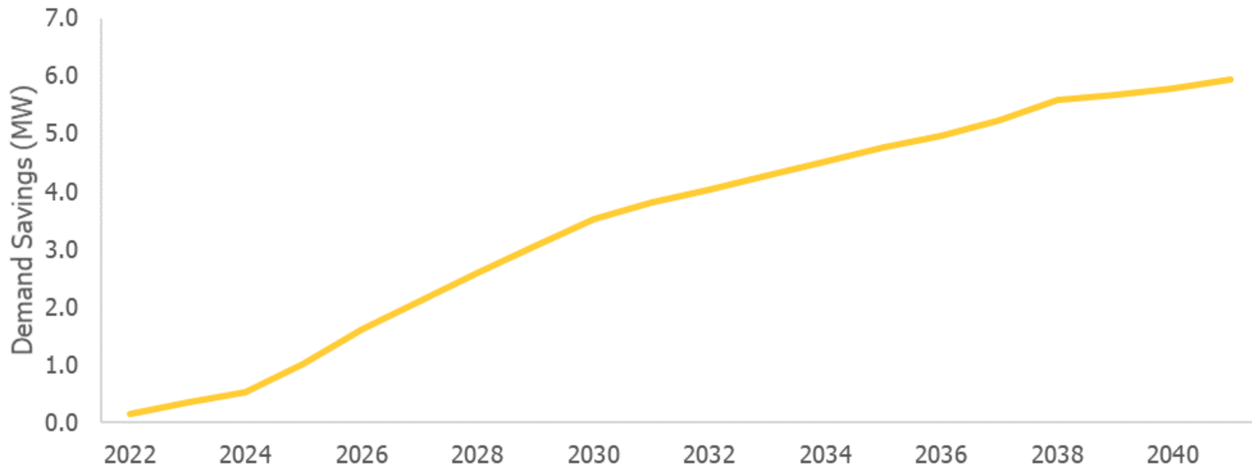
At the Beamsville TS, approximately 6.4 MW of uncommitted CDM savings potential is estimated to be achievable in 2041. The estimated cost to deliver these savings is $21.1 million dollars over the forecast period.

Figure 14 | Uncommitted CDM Potential at Beamsville TS



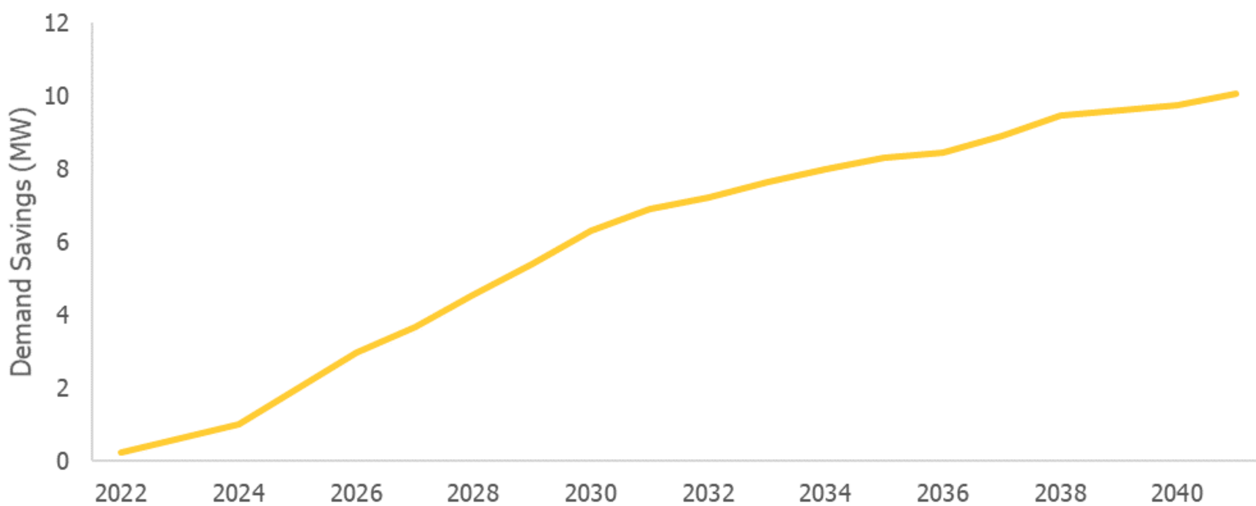
At the Kalar MTS, approximately 5.9 MW of uncommitted CDM savings potential is estimated to be achievable in 2041. The estimated cost to deliver these savings is $19.7 million dollars over the forecast period.

Figure 15 | Uncommitted CDM Potential at Kalar MTS



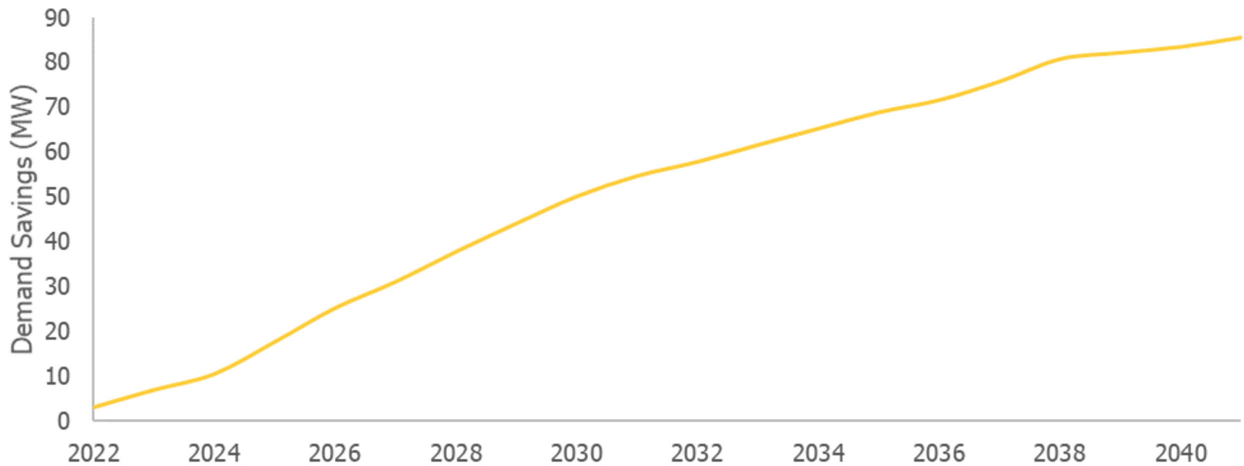
At the Crowland TS, approximately 10.1 MW of uncommitted CDM savings potential is estimated to be achievable in 2041. The estimated cost to deliver these savings is $33.4 million dollars over the forecast period.

Figure 16 | Uncommitted CDM Potential at Crowland TS



On the Niagara 115 kV sub-system, approximately 85 MW of uncommitted CDM savings potential is estimated to be achievable in 2041. The estimated cost to deliver these savings is $283 million dollars over the forecast period.

Figure 17 | Uncommitted CDM Potential on the Niagara 115 kV Sub-System



Appendix F. Economic Assumptions

The following is a list of the assumptions made in the economic analysis:

- The net present value ("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
- 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 Niagara region, based on escalating values from a previous study independently conducted for the IESO.[5]
- 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 Annual Technology Baseline.
- 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 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

[5] 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 (tCO_2e/GWh) for new gas facilities is assumed to be eliminated by 2030.

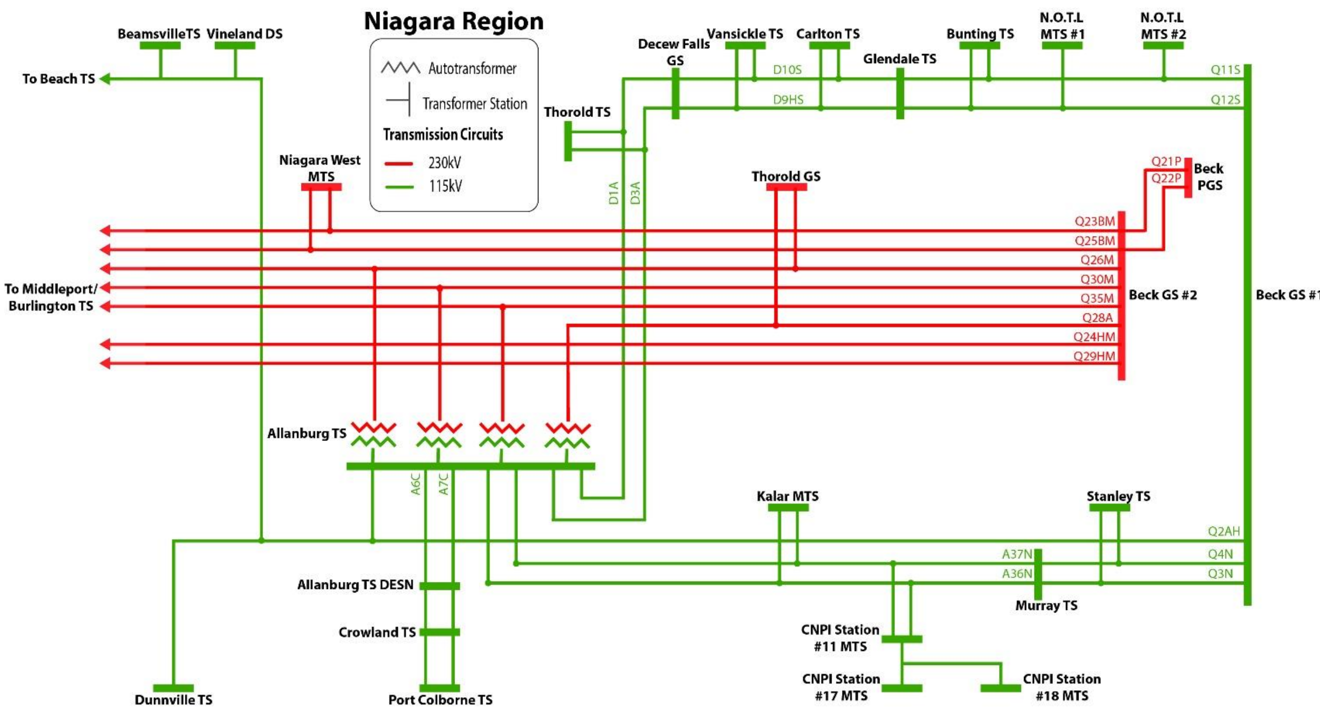
- The assessment was performed from an electricity consumer perspective and included all costs incurred by project developers, which were assumed to be passed on to consumers.

Appendix G. Niagara IRRP Technical Study

G.1 Description of Study Area

The study area for the Niagara Region primarily includes the 115 kV and 230 kV circuits and stations served from Sir Adam Beck Generating Station ("GS") #2 to Burlington TS and Middleport. A single line diagram of this region is shown in Figure 18 below.

Figure 18 | Single Line Diagram of the Niagara Region



G.2 Scenarios Assessed

Table 12 below summarizes the scenarios assessed. Further details on the local generation assumptions are discussed in the subsequent subsections. Information on the load forecast is found in Appendix B above. Note that all scenarios assume peak summer load conditions, consistent with the IRRP reference forecast. "Ref" scenarios correspond to reference growth, whereas "High" scenarios correspond to the high growth forecast. "AIS" indicates all in-service conditions, and import/export conditions of zero were assessed for the Niagara tie lines.

Table 12 | Summary of Scenarios Assessed

Scenario	Local Generation	Interface Flows[6]	Contingencies Assessed
Ref-AIS	All in-service	QFW: 710 MW - 375 MW	N-1, N-2
Ref-AIS	Thorold GS, all units out of service[7]	QFW: 530 MW – 185 MW	N-1, N-2
Ref-Outage	All in-service	QFW: 875 MW – 540 MW[8]	N-1-1, N-1-2
High-AIS	All in-service	QFW: 665 MW – 265 MW	N-1, N-2
High-AIS	Thorold GS, all units out of service	QFW: 480 MW – 75 MW	N-1, N-2

G.2.1 Load Forecast

The needs identification study used net peak summer forecast snapshots in 2022, 2023, 2026, 2031, and 2041 (end of planning horizon). The final published peak demand forecasts, by station, are provided in Appendix B.11 above. Table 13 summarizes the regional load levels for each of the study snapshot years used in the base case, since further updates were made to the planning forecast after the technical study began. Study results in the subsequent subsections are results specific to this forecast. Table 14 lists the power factors assumed for each station in the study.

Table 13 | Niagara Region Coincident Peak Forecast Used in Base Case (MW)

Year	2022	2023	2026	2031	2041
Total Peak Load (MW)	925	1100	1140	1185	1310

Table 14 | Load Power Factors Defined in Base Case[9]

Year	Power Factor
Allanburg TS	0.96
Beamsville TS	0.94
Bunting TS	0.94
Carlton TS	0.91

6 Interface flow range reflects the forecast load changes over the planning horizon/study snapshot years.

7 Thorold GS is the largest local generation unit.

8 Differs from the QFW flow range for Ref-AIS due to different dependable hydro assumptions for outage conditions.

9 Power factors of 0.9 were used to define station capacity needs and transformer 10-day emergency ratings, per ORTAC. Power factors listed in this table reflect historical data and existing performance, and were used in the study base case.

Year	Power Factor
CNPI Station #17 MTS	0.95
CNPI Station #18 MTS	0.95
Crowland TS	0.95
Dunnville TS	0.86
Glendale TS (T1/T2)	0.93
Glendale TS (T3/T4)	1
Kalar MTS	0.96
Murray TS (T13/T14)	0.92
Murray TS (T11/T12)	0.93
NOTL DS	0.97
NOTL York MTS	0.91
Port Colborne TS	0.96
Stanley TS	0.94
Thorold TS	0.93
Vansickle TS	0.92
Vineland DS	1
Niagara West MTS	0.99

G.2.2 Local Generation Assumptions

Generation facilities are tabulated in Table 15 and Table 16. Note that distribution-connected generation was already netted out in the load forecast based on summer peak contribution factors consistent with Appendix B.10.

The 98th percentile[10] and 85th percentile dependable output assumptions for hydro generation were specified depending on the outage scenario. 10 years of historical summer water flow data were used to calculate the Niagara Region hydro output values. To account for the new G1 and G2 units at Beck

[10] Based on Ontario Resource and Transmission Assessment Criteria ("ORTAC") requirements.

GS #1, as well as the plant's maneuverability, it was assumed that generation output at the Beck GS #1 could be shifted (i.e., dispatch down Beck GS #2 and dispatch up Beck GS #1) up to 490 MW[11] when required to mitigate or reduce violations.

Table 15 | Niagara Region Transmission-Connected Hydro Generation Summary

Facility Name	Contract Capacity (MW)	Dependable Capacity (MW): N-1 and N-2, 98th percentile, 8 hour	Dependable Capacity (MW): N-1-1 and N-1-2, 85th percentile, 8 hour
Beck GS #1	545	265	305
Beck GS #2	1499	926	1067
Decew Falls GS	167	100	115

Table 16 | Niagara Region Other Transmission-Connected Generation Summary

Facility Name	Fuel Type	Contract Capacity (MW)	Median Contribution to Historical Peak (MW)[12]
Thorold GS	Gas/Steam	242	200
Beck Pump GS	Storage	58	0 - assumed to not be providing any capacity relief, based on historical observations and uncertainties in behavior during future peak hours.

G.2.3 Major Interface Flows

The only major bulk transmission interface in the Niagara Region is Queenston Flow West ("QFW"), which may be impacted by the local area's load levels. QFW is defined as flow out of Beck GS #2 (Q25BM + Q23BM + Q24HM + Q29HM), plus flow in at Middleport (Q30M + Q26M + Q35M).

Studying QFW was out of the IRRP scope; it was only monitored to ensure flow was within System Control Order limits [13], but would be studied as part of any future bulk planning studies.

G.3 System Topology

G.3.1 Monitored Circuits and Sections

The bulk supply of the Niagara Region is currently met via the 230 kV transmission lines between Beck GS #2 and Middleport/Burlington, with particular emphasis on those that have terminations at Allanburg TS and the 230/115 kV autotransformers at Allanburg TS, which act as a single supply

[11] Corresponds to full output on 9 out of the 10 units at Beck GS #1.
[12] Median generation output during the past 10 years of coincident regional summer peaks (top 10% of load levels).
[13] QFW total transfer capability: 2025 MW [TPL Near-Term Transmission Planning Horizon Assessment – 2027].

point to the 115 kV sub-system. The downstream supply from Allanburg TS on the regional 115 kV transmission system comprises two main corridors:

1. Allanburg TS x Beck GS #1 via D1A-D3A-D10S-D9HS-Q11S-Q12S towards the north; and
2. Allanburg TS x Beck GS #1 via A36N-A37N-Q3N-Q4N towards the center of the region and Allanburg x Beck GS #1 via Q2AH with additional radial sections.

There is an additional double-circuit radial supply from the 115 kV sub-system towards the south via A6C and A7C. Table 17 below lists the monitored circuit sections and Table 18 lists the Allanburg transformer ratings.

Table 17 | Monitored Circuits and Ratings (Summer Ratings[14])

From Bus	To Bus	Continuous (MVA)	Long Term Emergency ("LTE") (MVA)	Short Term Emergency ("STE") (MVA)
ABIT_J_Q10P 220.	Q10P_STR_9_J220.	247.70	247.70	247.70
ABIT_J_Q10P 220.	ABIT_JQ28-10220.	468.70	533.50	533.50
ABIT_J_Q10P 220.	ABIT_JQ26-10220.	468.70	533.50	533.50
ABIT_J_Q26M 220.	CROSSLN_JQ26220.	605.90	724.00	724.00
ABIT_J_Q28A 220.	ABIT_JQ28-10220.	468.70	533.50	533.50
ABIT_J_Q35M 220.	CROSSLN_JQ35220.	605.90	724.00	724.00
ALLAN_DSN_A6118.	ALLAN_DSN_J6118.	157.40	169.70	169.70
ALLAN_DSN_A7118.	ALLAN_DSN_J7118.	157.40	169.70	169.70
ALLANB_JQ30M220.	ALLANBRG_Q30220.	605.90	724.00	724.00
ALLANB_JQ30M220.	MT_HOPE_JQ30220.	369.60	392.50	392.50
ALLANB_WJQ26220.	MIDDLEPT_DK1220.	583.00	697.30	697.30
ALLANB_WJQ26220.	CROSSLN_JQ26220.	583.00	697.30	697.30
ALLANB_WJQ35220.	CROSSLN_JQ35220.	583.00	697.30	697.30
ALLANB_WJQ35220.	ST_ANNS_TQ35220.	583.00	697.30	697.30
ALLANBRG_DH1118.	FIBRE_J_D3A 118.	206.50	229.00	229.00

[14] MVA values are on base voltage levels of 118.05 kV and 220 kV for 115 kV and 230 kV circuits respectively.

From Bus	To Bus	Continuous (MVA)	Long Term Emergency ("LTE") (MVA)	Short Term Emergency ("STE") (MVA)
ALLANBRG_DH1118.	ALLAN_DSN_J7118.	247.40	284.20	284.20
ALLANBRG_DH1118.	ALLAN_DSN_J6118.	247.40	284.20	284.20
ALLANBRG_DH1118.	KALAR_J_A36N118.	319.00	382.40	382.40
ALLANBRG_DH1118.	HOLLAND_RDJ1118.	206.50	229.00	229.00
ALLANBRG_DH1118.	D3A_T1FHKJCT118.	179.90	194.20	194.20
ALLANBRG_DH2118.	HOLLAND_RDJ2118.	200.40	222.90	222.90
ALLANBRG_DH2118.	KALAR_J_A37N118.	278.10	321.00	321.00
ALLANBRG_Q26220.	CROSSLN_JQ26220.	605.90	724.00	724.00
ALLANBRG_Q28220.	ABIT_J_Q28A 220.	373.40	373.40	373.40
ALLANBRG_Q35220.	CROSSLN_JQ35220.	605.90	724.00	724.00
ASW_STEEL_J 118.	ASW_STL_T2 118.	359.90	388.50	388.50
BEAMSVIL_Q2A118.	CHERRY_JQ2AH118.	243.30	280.10	280.10
BECK_#1_SS60118.	WARNER_RDJ11118.	243.30	280.10	280.10
BECK_#1_SS60118.	PORTAL_J_Q4N118.	243.30	280.10	280.10
BECK_#1_SS60118.	BECK_#1JQ2AH118.	200.40	222.90	222.90
BECK_#1_SS60118.	PORTAL_J_Q3N118.	243.30	280.10	280.10
BECK_#1_SS60118.	WARNER_RDJ12118.	243.30	280.10	280.10
BECK_#2_TS 220.	ALLANB_JQ30M220.	605.90	724.00	724.00
BECK_#2_TS 220.	NIA_WEST_J25220.	472.50	518.20	518.20
BECK_#2_TS 220.	ABIT_J_Q28A 220.	373.40	373.40	373.40
BECK_#2_TS 220.	HANNON_JQ29H220.	415.30	541.10	541.10
BECK_#2_TS 220.	BECK_#2_L301220.	1028.80	1650.00	1650.00

From Bus	To Bus	Continuous (MVA)	Long Term Emergency ("LTE") (MVA)	Short Term Emergency ("STE") (MVA)
BECK_#2_TS 220.	ABIT_J_Q35M 220.	605.90	724.00	724.00
BECK_#2_TS 220.	NIA_WEST_J23220.	445.80	472.50	472.50
BECK_#2_TS 220.	BECK_PS_Q21P220.	468.70	533.50	533.50
BECK_#2_TS 220.	ABIT_J_Q26M 220.	605.90	724.00	724.00
BECK_#2_TS 220.	BECK_PS_Q22P220.	468.70	533.50	533.50
BECK_#2_TS 220.	BECK_#2_L302220.	1028.80	1650.00	1650.00
BECK_#2_TS 220.	HANNON_JQ24H220.	480.10	529.70	529.70
BF_GOODR_JA6118.	HURRICAN_JA6118.	177.90	194.20	194.20
BF_GOODR_JA7118.	OXY_VINYLS 118.	85.90	85.90	85.90
BF_GOODR_JA7118.	HURRICAN_JA7118.	177.90	194.20	194.20
BF_GOODR_JA7118.	CYTEC_W_A7C 118.	114.50	114.50	114.50
BUNTING_Q11S118.	GLENDAL_JQ11118.	206.50	229.00	229.00
BUNTING_Q12S118.	GLENDAL_JQ12118.	206.50	229.00	229.00
CARLTON_D10S118.	LOUTH_J_D10S118.	145.20	145.20	145.20
CARLTON_D9HS118.	LOUTH_J_D9HS118.	145.20	145.20	145.20
CHERRY_JQ2AH118.	VINELAND_DS 118.	69.50	69.50	69.50
CHERRY_JQ2AH118.	LOUTH_J_Q2AH118.	243.30	280.10	280.10
CNP_#11_CTS 118.	MURRAY_A37Q4118.	134.90	134.90	134.90
CROWLAND_A6C118.	MICHIGAN_JA6118.	243.30	280.10	280.10
CROWLAND_A7C118.	MICHIGAN_JA7118.	243.30	280.10	280.10
CROWLAND_A7C118.	TUNNEL_J_C2P118.	200.40	222.90	222.90
DECEW_#1_GS 118.	DECEW_FLS_SS118.	206.50	222.90	222.90

From Bus	To Bus	Continuous (MVA)	Long Term Emergency ("LTE") (MVA)	Short Term Emergency ("STE") (MVA)
DECEW_FLS_SS118.	HOOPERS_JD3A118.	206.50	229.00	229.00
DECEW_FLS_SS118.	HOOPERS_JD9H118.	306.70	370.10	370.10
DECEW_FLS_SS118.	HOOPERS_JD10118.	306.70	370.10	370.10
DECEW_FLS_SS118.	HOOPERS_JD1A118.	276.00	327.10	327.10
DRESSER_JQ3N118.	NIAGARA_JQ3N118.	175.80	190.20	190.20
DRESSER_JQ4N118.	NIAGARA_J 118.	175.80	190.20	190.20
DRESSER_JQ4N118.	PORTAL_J_Q4N118.	198.30	220.80	220.80
DUNNVILLE_TS118.	ST_ANNS_J 118.	128.80	128.80	128.80
FIBRE_J_D1A 118.	HOLLAND_RDJ1118.	198.30	206.50	206.50
FIBRE_J_D1A 118.	GIBSON_J_D1A118.	198.30	206.50	206.50
GIBSON_J_D1A118.	THOROLD_D1A 118.	92.00	94.10	94.10
GIBSON_J_D1A118.	ST_JOHN_VJD1118.	198.30	206.50	206.50
GIBSON_J_D3A118.	ST_JOHN_VJD3118.	206.50	229.00	229.00
GIBSON_J_D3A118.	FIBRE_J_D3A 118.	335.30	396.70	396.70
GIBSON_J_D3A118.	THOROLD_D3A 118.	143.10	149.30	149.30
GLENDAL_JQ11118.	GLENDALE_D10118.	243.30	280.10	280.10
GLENDAL_JQ11118.	MCKINN_JQ11S118.	243.30	280.10	280.10
GLENDAL_JQ12118.	NOTL_Q12S#1J118.	243.30	280.10	280.10
GLENDAL_JQ12118.	GLENDALE_D9H118.	243.30	280.10	280.10
GLENDALE_D10118.	LOUTH_J_D10S118.	182.00	198.30	198.30
GLENDALE_D9H118.	LOUTH_J_D9HS118.	182.00	198.30	198.30
HOLLAND_RDJ1118.	RESFP_THORLD118.	122.70	126.80	126.80

From Bus	To Bus	Continuous (MVA)	Long Term Emergency ("LTE") (MVA)	Short Term Emergency ("STE") (MVA)
HOLLAND_RDJ2118.	ST_JOHN_VJQ2118.	200.40	222.90	222.90
HOLLAND_RDJ2118.	BECK_#1JQ2AH118.	200.40	222.90	222.90
HOOPERS_JD1A118.	ST_JOHN_VJD1118.	198.30	206.50	206.50
HOOPERS_JD3A118.	ST_JOHN_VJD3118.	276.00	327.10	327.10
HURRICAN_JA6118.	ALLAN_DSN_J6118.	247.40	284.20	284.20
HURRICAN_JA6118.	MICHIGAN_JA6118.	247.40	284.20	284.20
HURRICAN_JA7118.	ALLAN_DSN_J7118.	247.40	284.20	284.20
HURRICAN_JA7118.	MICHIGAN_JA7118.	247.40	284.20	284.20
INCO_J_A6C 118.	PT_COLB_A6C 118.	85.90	85.90	85.90
INCO_J_C2P 118.	PT_COLB_C2P 118.	200.40	222.90	222.90
INCO_J_C2P 118.	JBL_J_C2P 118.	200.40	222.90	222.90
INCO_J_C2P 118.	INCO_60_HZ 118.	85.90	85.90	85.90
JBL_J_C2P 118.	JBL_CSS 118.	157.40	169.70	169.70
KALAR_J_A37N118.	MURRAY_A37Q4118.	278.10	321.00	321.00
KALAR_MTSA36118.	KALAR_J_A36N118.	218.80	245.40	245.40
KALAR_MTSA37118.	KALAR_J_A37N118.	218.80	245.40	245.40
LOUTH_J_D10S118.	VANSICKLE_10118.	182.00	198.30	198.30
LOUTH_J_D9HS118.	VANSICKLE_D9118.	182.00	198.30	198.30
MCKINN_JQ11S118.	NOTL_Q11S#1J118.	243.30	280.10	280.10
MICHIGAN_JD3118.	D3A_T1FHKJCT118.	179.90	194.20	194.20
MICHIGAN_JD3118.	ASW_STEEL_J 118.	177.90	177.90	177.90
MURRAY_A36Q3118.	KALAR_J_A36N118.	319.00	382.40	382.40

From Bus	To Bus	Continuous (MVA)	Long Term Emergency ("LTE") (MVA)	Short Term Emergency ("STE") (MVA)
MURRAY_A36Q3118.	NIAGARA_JQ3N118.	175.80	190.20	190.20
NIAGARA_J 118.	MURRAY_A37Q4118.	198.30	220.80	220.80
NOTL_MTS_#1 118.	NOTL_Q12S#1J118.	182.00	198.30	198.30
NOTL_MTS_#2 118.	WARNER_RDJ11118.	114.50	116.50	116.50
PAN_ABRASIVE118.	TUNNEL_J_C2P118.	141.10	149.30	149.30
PELHAM_J 118.	ROSEDENE_JQ2118.	141.10	149.30	149.30
PORTAL_J_Q3N118.	STANLEY_Q3N 118.	276.00	327.10	327.10
PORTAL_J_Q3N118.	DRESSER_JQ3N118.	198.30	220.80	220.80
RSFPTHRLD230220.	THOROLD_CGSJ220.	247.70	247.70	247.70
ST_ANNS_JQ2A118.	ROSEDENE_JQ2118.	75.70	75.70	75.70
ST_JOHN_VJQ2118.	PELHAM_J 118.	224.90	257.60	257.60
ST_JOHN_VJQ2118.	LOUTH_J_Q2AH118.	243.30	280.10	280.10
STANLEY_Q4N 118.	PORTAL_J_Q4N118.	276.00	327.10	327.10
THOROLD_CGS 220.	THOROLD_CGSJ220.	457.30	457.30	457.30
THOROLD_CGSJ220.	Q10P_STR_9_J220.	247.70	247.70	247.70
TUNNEL_J_A6C118.	CROWLAND_A6C118.	157.40	169.70	169.70
TUNNEL_J_A6C118.	INCO_J_A6C 118.	85.90	85.90	85.90
TUNNEL_J_C2P118.	JBL_J_C2P 118.	200.40	222.90	222.90
VANSICKLE_10118.	HOOPERS_JD10118.	306.70	370.10	370.10
VANSICKLE_D9118.	HOOPERS_JD9H118.	306.70	370.10	370.10
WARNER_RDJ11118.	NOTL_Q11S#1J118.	243.30	280.10	280.10
WARNER_RDJ12118.	NOTL_Q12S#1J118.	243.30	280.10	280.10

Table 18 | Ratings of Allanburg Transformers

ID	Primary Bus Name	Secondary Bus Name	Tertiary Bus Name	Primary Rating (MVA)		
				Cont	LTE	STE
T1	ALLANBRG_Q26220.	ALLANBURG_R1118.	ALLANBURG_T113.4	250.00	409.00	502.40
T2	ALLANBRG_Q28220.	ALLANBURG_R2118.	ALLANBURG_T213.4	250.00	406.50	460.60
T3	ALLANBRG_Q30220.	ALLANBURG_R3118.	ALLANBURG_T313.4	250.00	308.20	395.80
T4	ALLANBRG_Q35220.	ALLANBURG_R4118.	ALLANBURG_T413.4	250.00	406.50	460.60

G.3.2 Remedial Action Schemes

Table 19 below shows the available remedial action schemes in the study region. When permissible according to ORTAC, these will be used first and foremost when any needs are identified by the studies.

Table 19 | Relevant Remedial Action Schemes

Facility	Description
Allanburg Load Rejection Scheme	Designed to prevent post-contingency voltage decline for the coincidental loss of Allanburg T1 & T2.
Q11S/Q12S Undervoltage Protection at Glendale TS	Designed to address post-contingency low voltages at Niagara-on-the-Lake MTS stations due to loss of supply from Beck 1 when either D10S or D9HS is out-of-service.

G.4 Credible Planning Events and Criteria

G.4.1 Planning Criteria

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

- North American Electric Reliability Corporation TPL-001 "Transmission System Planning Performance Requirements";
- Northeast Power Coordinating Council Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System"; and
- IESO ORTAC.

G.4.2 Studied Contingencies

Table 20 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 per ORTAC.

Table 20 | Type of Contingencies Assessed

Pre-Contingency	Contingency[15]	Type	Mapping to TPL/Directory 1 Event	Rating[16]	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[17]; 150 MW total
	Double	N-2	N/A	STE, reduced to LTE	>150 MW lost by curtailment[18]; 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; 600 MW total
	Double	N-1-2	Cat II	STE, reduced to LTE	N/A

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

- Contingency events that result in the same post-contingency state as other contingencies already documented may be omitted; and
- The outage events used for the N-1-1 studies are very similar to the N-1 contingencies documented in Table 21 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.

[15] 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.

[16] 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.

[17] Only to account for the magnitude of the generation outages.

[18] Only to account for the magnitude of the generation outages.

Table 21 | Studied N-1 Contingencies

Contingencies

Q23BM	Q25BM	Q26M	Q30M	Q35M	Q28A
Q24HM	Q29HM	Q21P	Q22P	Q3N	A36N
Q4N	A37N	Line 2	Q2AH	Q11S	D10S
Q12S	D9HS	D3A	D1A	D2D	A6C
A7C	C2P	Allanburg T1, T2, T3, T4	Beck 2 D1, D2, K1, K2 bus	Allanburg D1, D2, H1, H2 bus	Beck 1 E bus
Thorold GTG1, STG2	Beck 2 T25, T23, T21, T19, T17, T15, T13, T11	Decew Falls G1, G2	Beck 1 G1, G2, G3, G4, G5, G6, G7, G8, G9, G10		

Table 22 | Studied N-2 Common Tower Contingencies

Contingencies

M31W+Q23BM	Q23BM+Q24HM	Q23BM+Q25BM	M32W+Q25BM
Q25BM+Q26M	Q25BM+Q29HM	Q25BM+Q30M	Q26M+Q28A
Q26M+Q35M	M27B+Q30M	Q30M+Q35M	Q28A+Q29HM
M21D +Q24HM	Q24HM+Q29HM	M20D+Q29HM	

Table 23 | Studied N-2 Breaker Failures

Station	Breakers
Beck GS #2	D1D2, K1K2, D1L24, D1L27, DL30, DT301, D1L302, K1L23
Beck GS #2	K1L25, K1TL26, KL29, KL76, L25L302, L28T301, L30L35, L35L76
Beck GS #2	TL21L23, TL21L24, TL26L27, TL28L29
Allanburg TS	None

G.5 Study Result Findings (Existing Transmission System)

The following section describes the findings of the system studies. The results are presented under each applicable scenario as described in Table 12 above.

Per Table 20:

- Transmission system loading for the loss of a double contingency can go up to STE ratings if there are control actions 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.
- LTE rating should not be exceeded for the loss of a single contingency with the largest local generator out of service.
- Transmission system loading under outage conditions for the loss of a single contingency can go up to STE ratings if there are control actions 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.

G.5.1 All Elements in Service – Loss of Single Contingency

No issues have been identified with all elements in service for a single contingency.

G.5.2 All Elements in Service – Loss of Double Contingency

With all elements in service, the following was seen for loss of a double contingency:

- Allanburg T3 transformer exceeds the LTE rating for the loss of Q26M+Q35M by 6% in 2026, 9% in 2031, and 27% in 2041. However, given Beck GS #1 re-dispatch maneuverability as stated in Section G.2.2, these overloads can be reduced below LTE. Similar loadings are seen for the loss of Q26M+Q28A, but that particular double contingency triggers the Allanburg Load Rejection Scheme and provides sufficient relief on its own.
- Allanburg T1 transformer exceeds the LTE rating for the loss of Q30M+Q35M by 3% in 2041. However, given Beck GS #1 re-dispatch maneuverability as stated in Section G.2.2, this overload can be reduced below LTE.
- Load loss criteria violation: Q26M+Q28A double contingency triggers the Allanburg Load Rejection Scheme, which trips A6C and A7C circuits. The amount of load loss from this scheme is greater than the maximum of 150 MW permitted from curtailment by 30 MW in 2022 (base year), and grows thereafter to the exceed limit by 75 MW in 2041. This load security violation is expected to grow to the end of the IRRP planning horizon, and is summarized below.

Table 24 | A6C/A7C Load Security Need

Limiting Contingency	ORTAC Limit (MW)	2022 Load (MW)	2026 Load (MW)	2031 Load (MW)	2041 Load (MW)
Q26M+Q28A	150	180	205	215	225

G.5.3 Local Generation Out of Service – Loss of Single Contingency

The following was seen with Thorold GS out of service for loss of a single contingency:

- Q28A-Beck section exceeds the LTE and STE ratings[19] for the loss of Beck 1 E-bus by 2% in 2026 and 6% in 2041. Beck GS #1 re-dispatch maneuverability as stated in Section G.2.2 provides no help for this case. Lower overloads are seen for the loss of Q26M, Q30M, or Q35M at 5%, 4% and 4% respectively on the 2041 case – but given Beck GS #1 re-dispatch capability, these overloads can be reduced below LTE.

G.5.4 Local Generation Out of Service – Loss of Double Contingency

The following was seen with Thorold GS out of service for loss of a double contingency:

- Allanburg T3 transformer exceeds the LTE rating for the loss of Q26M+Q35M by 1% in 2023, 12% in 2026, 16% in 2031, and 34% in 2041. However, given Beck GS #1 re-dispatch maneuverability as stated in Section G.2.2, these overloads can be reduced below LTE. This double contingency also results in T3 exceeding the STE rating by 5% on 2041, but with Beck GS #1 re-dispatch, the pre-contingency conditions can be assumed to be different such that there is no STE violation post-contingency. Note that this is not the most limiting condition causing T3 overload; more details on this are discussed in subsequent subsections.

Lower overloads on T3 are seen as well for the loss of Q26M+Q28A (from the 2026 case onwards). However, this particular double contingency triggers the Allanburg Load Rejection Scheme, which provides sufficient relief.

- Allanburg T1 transformer exceeds the LTE rating for the loss of Q30M+Q35M by 8% in 2041. However, with Beck GS #1 re-dispatch, this overload can be reduced below LTE.
- Q28A-Beck section exceeds the LTE and STE ratings for the loss of Q26M+Q35M by 16% in 2023, 25% in 2026, 27% in 2031, and 39% in 2041. However, with Beck GS #1 re-dispatch, this overload can be reduced below LTE/STE for each of the stated years – except for 2041 where it still would fall short by 40 MW (e.g., it needs a 115 kV net load reduction of 40 MW via decrease load or increase local generation to reduce the overload below LTE/STE).

Similar (only very slightly lower) overloads on the Q28A-Beck section are seen as well for the loss of Q30M+Q35M.

Very mild overloads are seen for the loss of Q25BM+Q26M and Q25BM+Q30M, at 5% and 4% respectively on the 2041 case. With Beck GS #1 re-dispatch, these overloads can be reduced below LTE/STE.

G.5.5 Q28A Outage – Loss of Double Contingency

With Q28A out of service, the following was seen for loss of a double contingency:

- Allanburg T3 exceeds the LTE rating for the loss of Q26M+Q35M by 62% in 2022 (base year), 64% in 2023, 80% in 2026, 95% in 2031, and 139% in 2041. With Beck GS #1 re-dispatch, there is still a violation by 9 MW in 2022, 15 MW in 2023, 59 MW in 2026, 101 MW in 2031, and 223

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[19] LTE and STE ratings are the same for this circuit section.

MW in 2041 (i.e., require a 115 kV net load reduction of 9 MW to reduce the overload below LTE in 2022). A load rejection scheme of up to 150 MW could provide sufficient relief up to a year between 2031 and 2041. It is also seen that due to this double contingency, T3 exceeds the STE ratings by 26% in 2022 (base year), 27% in 2023, 40% in 2026, 52% in 2031, and 86% in 2041. However, with Beck GS #1 re-dispatch, the pre-contingency conditions can be assumed to be different such that there is no STE violation post-contingency for each of the stated years except for 2031 and 2041, where it falls short by 22MW and 143MW respectively (i.e., require a 115 kV net load reduction of 22 MW to reduce the overload below STE in 2031).

A smaller LTE overload is seen for the loss of Q25BM+Q26M at 17% on the 2041 case, which can be mitigated by Beck GS #1 re-dispatch.

- Allanburg T1 transformer exceeds the LTE rating for the loss of Q30M+Q35M by 29% in 2022 (base year), 30% in 2023, 42% in 2026, 53% in 2031, and 85th percentile in 2041. T1 exceeds the STE ratings by 5% in 2022 (base year), 6% in 2023, 15% in 2026, 24% in 2031, and 51% in 2041. These overloads have a similar nature as those seen for T3, but are smaller (not the most limiting) and can be addressed by the same solution provided for T3.

G.5.6 Q28A Outage – Loss of Single Contingency

With Q28A out of service, the following was seen for loss of a single contingency:

- Allanburg T3 exceeds the LTE rating for the loss of Q26M, Q35M, and Beck 1 E-bus by 17%, 15%, and 14% respectively in 2041.

G.5.7 Q30M Outage – Loss of Double Contingency

With Q30M out of service, the following were seen for a double contingency:

- Allanburg T4 exceeds the LTE rating for the loss of Q26M+Q28A by 23% in 2022 (base year), 24% in 2023, 36% in 2026, 48% in 2031, and 81% in 2041. However, this particular double contingency triggers the Allanburg Load Rejection Scheme, which provides sufficient relief in all study years except 2041 (the overload is reduced to 17%). Nevertheless, given Beck GS #1 re-dispatch maneuverability, this remaining overload can be reduced below LTE. Similarly, this double contingency results in T4 exceeding the STE ratings by 8% in 2022 (base year), 9% in 2023, 20% in 2026, 30% in 2031, and 60% in 2041. This double contingency also triggers the Allanburg Load Rejection Scheme, which provides sufficient relief except in 2041 where the overload is reduced to 4%. That said, with Beck GS #1 re-dispatch as stated in Section G.2.2, the pre-contingency conditions can be assumed to be different such that there is no STE violation post-contingency. Note that these overloads are similar in nature as those seen for T3 in the previous section, but are comparatively less severe (i.e., T4 is not the most limiting bank) and can be addressed by (or benefit from) the same solution provided to address T3 limitation.
- Allanburg T2 exceeds the LTE rating for the loss of Q26M+Q35M by 22% in 2022 (base year), 23% in 2023, 35% in 2026, 46% in 2031, and 80% in 2041. T2 also exceeds the STE ratings by 8% in 2022 (base year), 9% in 2023, 19% in 2026, 29% in 2031, and 59% in 2041. These overloads are similar in nature as those seen for T3 on a previous section, but are less severe (i.e., T2 is not the most limiting bank) and can be addressed by (or benefit from) the same solution provided to address T3 limitation.

- Q28A-Beck section exceeds the LTE and STE ratings for the loss of Q26M+Q35M by 23% in 2023, 36% in 2026, 48% in 2031, and 84% in 2041. However, with Beck GS #1 re-dispatch, this overload can be reduced below LTE/STE for each of the stated years – except for 2041 where it still would fall short by 100 MW (i.e., require a 115 kV net load reduction of 100 MW). However, this section is more limiting under local generation outage conditions (as described previously). Thus the solution provided under that scenario would inherently address this overload.
- Q28A-Allanburg section exceeds the LTE and STE ratings[20] for the loss of Q26M+Q35M by 26% in 2022 (base year), 27% in 2023, 41% in 2026, 53% in 2031, and 91% in 2041. However, given Beck GS #1 re-dispatch, this overload can be reduced below LTE/STE for each of the stated years – except for 2041 where it still would fall short by 125 MW (i.e., require a 115 kV net load reduction of 125 MW). This limitation is under outage conditions and can benefit from the same 150 MW of load rejection relief that may be implemented to address the T3 limitation under Q28A outage conditions (mentioned previously), as they are both triggered by the same double contingency. Alternative solutions like reconductoring or tensioning of the section could be considered.

G.5.8 Q26M Outage – Loss of Double Contingency

With Q26M out of service, the following was seen for loss of a double contingency:

- Allanburg T2 exceeds the LTE rating for the loss of Q30M+Q35M by 35% in 2026, 46% in 2031, and 80% in 2041. Similarly, T2 exceeds the STE ratings by 19% in 2026, 29% in 2031, and 59% in 2041. These are similar in nature as the T2 overloads due to the loss of Q26M+Q35M under Q30M outage (thus, 2022 and 2023 were not studied but similar results were expected).
- Q28A-Beck section exceeds the LTE and STE ratings for the loss of Q30M+Q35M by 36% in 2026, 48% in 2031, and 84% in 2041. These are similar in nature as the Q28A-Beck section overloads due to the loss of Q26M+Q35M under Q30M outage (thus 2023 was not studied but similar results were expected).
- Q28A-Allanburg section exceeds the LTE and STE ratings for the loss of Q30M+Q35M by 41% in 2026, 53% in 2031, and 91% in 2041. These are similar in nature as the Q28A-Allanburg section overloads due to the loss of Q26M+Q35M under Q30M outage (thus 2022 and 2023 were not studied but similar results were expected).
- Allanburg T3 transformer exceeds the LTE rating for the loss of Q28A+Q29HM by 17% in 2041.

G.5.9 Q26M Outage – Loss of Single Contingency

With Q26M out of service, the following was seen for loss of a single contingency:

- Allanburg T3 exceeds the LTE rating for the loss of Q35M, Q28A, and Beck GS #1 E-bus by 17%, 17%, and 20% respectively in 2041. Allanburg T3 exceeds the LTE rating for the loss of Beck GS #1 E-bus by 2% in 2031.
- Q28A-Beck section exceeds the LTE and STE ratings for the loss of Thorold GS by 2% in 2041.

[20] LTE and STE ratings are the same for this circuit section.

G.5.10 Q26M Outage – Pre-contingency

- Dunnville 115 kV (Q2AH) and Beamsville 115 kV (Q2AH) exceed the pre-contingency bus voltage limits at 112 kV for both stations in 2041.

G.5.11 Q35M Outage – Loss of Double Contingency

With Q35M out of service, the following was seen for loss of a double contingency:

- Allanburg T3 exceeds the LTE rating for the loss of Q26M+Q28A by 95% in 2031, and 139% in 2041. Similarly, due to this double contingency, T3 exceeds the STE ratings by 52% in 2031, and 86% in 2041. These are similar in nature as the T3 overloads due to the loss of Q26M+Q35M under Q28A outage (thus 2022, 2023, and 2026 were not studied but similar results were expected). This particular Q26M+Q28A double contingency triggers the Allanburg Load Rejection Scheme, which provides relief (T3 LTE overload is reduced to 17% and 55% for 2031 and 2041 respectively).
- Allanburg T3 exceeds the LTE rating for the loss of Q28A+Q29HM and Q25BM+Q26M by 15% and 16% respectively in 2041.

G.5.12 Q35M Outage – Loss of Single Contingency

With Q35M out of service, the following was seen for loss of a single contingency:

- Allanburg T3 exceeds the LTE rating for the loss of Q26M, Q28A, and Beck GS #1 E-bus by 17%, 15%, and 15% respectively in 2041.

G.5.13 Q24HM or Q29HM Outage – Loss of Double Contingency

With Q24HM or Q29HM out of service, the following was seen for loss of a double contingency:

- Allanburg T3 exceeds the LTE rating for the loss of Q26M+Q35M and Q26M+Q28A by 17% and 18% respectively in 2041.

G.5.14 Q23BM or Q25BM Outage – Loss of Double Contingency

With Q23BM or Q25BM out of service, the following was seen for loss of a double contingency:

- Allanburg T3 exceeds the LTE rating for the loss of Q26M+Q35M and Q26M+Q28A by 17% and 18% respectively in 2041.

G.5.15 D3A Outage – Loss of Single Contingency

With D3A out of service, the following was seen for loss of a single contingency:

- D1A-(Fibre_J to Gibson_J) section and D1A-(Fibre_J to Holland_RDJ) section exceed the LTE and STE ratings[21] for the loss of Beck GS #1 E-bus by 4% in 2026, 14% in 2031, and 65% in 2041.

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[21] LTE and STE ratings are the same for this circuit section.

- D1A-(Allanburg_DH to Holland_RDJ) section exceeds the LTE and STE ratings[22] for the loss of Beck GS #1 E-bus by 4% in 2031 and 50% in 2041.
- D1A-(Gibson_J to St_John_VJ) section and D1A-(St_John_VJ to Hoopers_J) section exceed the LTE and STE ratings[23] for the loss of Beck GS #1 E-bus by 0.3% in 2031 and 50% in 2041.
- Vansickle 115 kV (Q11S/Q12S), Carlton 115 kV (Q11S/Q12S), Glendale 115 kV (Q11S/Q12S), Bunting 115 kV (Q11S), and NOTL MTS #2 115 kV (Q11S) exceed the post-contingency bus voltage limits for the loss of Beck GS #1 E-bus at 107 kV, 106 kV, 105 kV, 104 kV, and 104 kV respectively in 2041.

G.5.16 D1A Outage – Loss of Single Contingency

With D1A out of service, the following was seen for loss of a single contingency:

- D3A-(Allanburg_DH to Fibre_J) section, D3A-(Decew_Fls to Hoopers_J) section and D3A-(Gibson_J to St_John_VJ) section exceed the LTE and STE ratings[24] for the loss of Beck GS #1 E-bus by 43%, 31% and 31% in 2041. No further assessments were done on remaining snapshot years.

G.5.17 A36N Outage – Loss of Single Contingency

With A36N out of service, the following was seen for loss of a single contingency:

- A37N-(Allanburg to Kalar_J) section exceeds the LTE and STE ratings[25] for the loss of Beck GS #1 E-bus by 4.5% in 2031 and 17% in 2041.

G.5.18 Q12S Outage – Loss of Single Contingency

With Q12S out of service, the following was seen for loss of a single contingency:

- D10S-(Vansickle to Louth J) section exceeds the LTE and STE ratings[26] for the loss of Beck GS #1 E-bus by 26% in 2041.

G.5.19 Q11S Outage – Loss of Single Contingency

With Q11S out of service, the following was seen for loss of a single contingency:

- D9HS-(Vansickle to Louth J) section exceeds the LTE and STE ratings[27] for the loss of Beck GS #1 E-bus by 17% in 2041.

G.5.20 D9HS Outage – Loss of Single Contingency

With D9HS out of service, the following was seen for loss of a single contingency:

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[22] LTE and STE ratings are the same for this circuit section.
[23] LTE and STE ratings are the same for this circuit section.
[24] LTE and STE ratings are the same for this circuit section.
[25] LTE and STE ratings are the same for this circuit section.
[26] LTE and STE ratings are the same for this circuit section.
[27] LTE and STE ratings are the same for this circuit section.

- D10S-(Vansickle to Louth J) section exceeds the LTE and STE ratings for the loss of Beck GS #1 E-bus by 27% in 2022 (base year), 28% in 2023, 34% in 2026, 46% in 2031, and 101% in 2041. However, with the Q11S/Q12S Undervoltage Protection Scheme at Glendale TS along with the Bunting split control action, these thermal overloads are relieved for 2022 and 2023, and reduced to 2% in 2026, 10% in 2031, and 44% in 2041.
- D10S-(Decew_Fls to Hoopers_J) section, D10S-(Vansickle to Hoopers_J) and D10S-(Glendale to Louth J) exceeds the LTE and STE ratings[28] for the loss of Beck GS #1 E-bus by 32%, 32%, and 34% respectively in 2041. However, with the Q11S/Q12S Undervoltage Protection Scheme at Glendale TS along with the Bunting split control action, these thermal overloads are relieved.
- Glendale 115 kV (Q12S), Bunting 115 kV (Q12S) and NOTL MTS #1 115 kV (Q12S) exceed the post-contingency bus voltage limits for the loss of Beck GS #1 E-bus at 106 kV in 2022 (base year) worsening thereafter in each snapshot year. However, with the Q11S/Q12S Undervoltage Protection Scheme at Glendale TS, these voltage violations are mitigated.

G.5.21 D10S Outage – Loss of Single Contingency

With D10S out of service, the following was seen for loss of a single contingency:

- D9HS-(Vansickle to Louth J) section exceeds the LTE and STE ratings for the loss of Beck GS #1 E-bus by 29% in 2022(base year), 30% in 2023, 37% in 2026, 51% in 2031 and undefined% (diverging) in 2041. However, with the Q11S/Q12S Undervoltage Protection Scheme at Glendale TS and the Bunting split control action, these thermal overloads are relieved for all years except 2041, where it is reduced to 31%.
- D9HS-(Glendale to Louth J) exceeds the LTE and STE ratings[29] for the loss of Beck GS #1 E-bus by 2% in 2031 and undefined % (diverging) in 2041. However, with the Q11S/Q12S Undervoltage Protection Scheme at Glendale TS and the Bunting split control action, these thermal overloads are relieved.
- Glendale 115 kV (Q11S), Bunting 115 kV (Q11S) and NOTL MTS #2 115 kV (Q11S) exceed the post-contingency bus voltage limits for the loss of Beck GS #1 E-bus at 105kV in 2022(base year) worsening thereafter on each snapshot year. However, with the Q11S/Q12S Undervoltage Protection Scheme at Glendale TS, these voltage violations are mitigated.

G.5.22 A6C, A7C, Q4N Outage – Loss of Single Contingency

No issues were identified.

G.6 115 kV Sub-System Supply Capacity Need with Reinforcements

The study results in Section G.5 show that a supply capacity need arises on the 115 kV sub-system. The limiting phenomena are summarized again in the tables below for the existing transmission system, as well as according to different reinforcement scenarios. Note that these results are specific to the forecast specified in Section G.2.1 and generation dispatch according to Section G.2.2.

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[28] LTE and STE ratings are the same for this circuit section.

[29] LTE and STE ratings are the same for this circuit section.

Table 25 | 115 kV Sub-System Supply Capacity Need – No Reinforcement

Outage Condition	Limiting Contingency	Limiting Phenomenon	Permissible Load Growth on the 115 kV Sub-System with Respect to 2022 Load Levels (MW)	
			With No Load Rejection	With 150 MW of Load Rejection
Thorold GS	Beck GS #1 E-bus	Q28A (Beck section)	53	Not Permissible
Thorold GS	Q26M+Q35M	Q28A (Beck section)	73	Not Permissible
Q30M	Q26M+Q35M	Q28A (Allanburg section)	78	228
Q28A	Q26M+Q35M	Allanburg T3	-9	141

Table 26 | 115 kV Sub-System Supply Capacity Need – Crowland 230 kV Reinforcement

Outage Condition	Limiting Contingency	Limiting Phenomenon	Permissible Load Growth on the 115 kV Sub-System with Respect to 2022 Load Levels (MW)	
			With No Load Rejection	With 150 MW of Load Rejection
Thorold GS OS	Beck GS #1 E-bus	Q28A (Beck section)	152	Not Permissible
Thorold GS OS	Q26M+Q35M	Q28A (Beck section)	168	Not Permissible
Q30M	Q26M+Q35M	Q28A (Allanburg section)	170	320
Q28A	Q26M+Q35M	Allanburg T3	85	232

Table 27 below contains study results for a sensitivity scenario: omission of the 150 MW new transmission-connected customer (supplied from Q10P) that is included in the IRRP reference forecast. Under this scenario, the results indicate that the thermal overload of Q28A (Beck section) is no longer one of the most limiting phenomena for overall Niagara 115 kV supply.

Table 27 | 115 kV Sub-System Supply Capacity Need – Crowland 230 kV Reinforcement, No Large New Industrial Customer

Outage Condition	Limiting Contingency	Limiting Phenomenon	Permissible Load Growth with Respect to 2022 Load Levels (MW)	
			With No Load Rejection	**With 150 MW of Load Rejection**
Thorold GS OS	Beck GS #1 E-bus	Allanburg T3	376	Not Permissible
Thorold GS OS	Q26M+Q35M	Allanburg T3	312	Not Permissible
Q30M	Q26M+Q35M	Q28A (Allanburg section)	169	319
Q30M	Q26M+Q28A	Allanburg T4	179	329
Q30M	Q26M+Q35M	Allanburg T2	179	329
Q28A	Q26M+Q35M	Allanburg T3	85	235

Table 28 | 115 kV Sub-System Supply Capacity Need – Allanburg 230 kV Bus Reinforcement

Outage Condition	Limiting Contingency	Limiting Phenomenon	Permissible Load Growth on the 115 kV Sub-System with Respect to 2022 Load Levels (MW)	
			With No Load Rejection	**With 150 MW of Load Rejection**
Thorold GS OS	Beck GS #1 E-bus	Q28A (Beck section)	349	Not Permissible
Thorold GS OS	Q30M+Q35M	Q28A (Beck section)	169	Not Permissible
Q30M	Q26M+Q35M	Q28A (Allanburg section)	41	191
Q28A	Beck GS #1 E-bus	Allanburg T3	347	497
T1	Beck GS #1 E-bus	Allanburg T3	71	221

Table 29 | 115 kV Sub-System Supply Capacity Need – Allanburg 230/115 kV Extra Transformer Reinforcement (Tapping on Q24HM)

Outage Condition	Limiting Contingency	Limiting Phenomenon	Permissible Load Growth on the 115 kV Sub-System with Respect to 2022 Load Levels (MW)	
			With No Load Rejection	With 150 MW of Load Rejection
Thorold GS OS	Beck GS #1 E-bus	Q28A (Beck section)	288	Not Permissible
Thorold GS OS	Q26M+Q35M	Q28A (Beck section)	296	Not Permissible
Q30M	MaxOut	N/A	401	551
Q28A	Q26M+Q35M	Allanburg T3	254	404
Q28A	Beck GS #1 E-bus	Allanburg T3	284	434