Burlington to Nanticoke Integrated Regional Resource Plan

Appendices

March 10, 2026

Disclaimer

This document and the information contained herein is provided for informational purposes only. The IESO has prepared this document based on information currently available to the IESO and reasonable assumptions associated therewith, including relating to electricity supply and demand. The information, statements and conclusions contained in this document are subject to risks, uncertainties and other factors that could cause actual results or circumstances to differ materially from the information, statements and assumptions contained herein. The IESO provides no guarantee, representation, or warranty, express or implied, with respect to any statement or information contained herein and disclaims any liability in connection therewith. Readers are cautioned not to place undue reliance on forward-looking information contained in this document, as actual results could differ materially from the plans, expectations, estimates, intentions and statements expressed herein. The IESO undertakes no obligation to revise or update any information contained in this document as a result of new information, future events or otherwise. In the event there is any conflict or inconsistency between this document and the IESO market rules, any IESO contract, any legislation or regulation, or any request for proposals or other procurement document, the terms in the market rules, or the subject contract, legislation, regulation, or procurement document, as applicable, govern.

Table of Contents

List of Figures

List of Tables

List of Acronyms

Acronym	Definition
BESS	Battery Energy Storage System
CDM	Conservation and Demand Management
DESN	Dual-Element Spot Network
DG	Distributed Generation
DLT	Distribution-level Load Transfers
DR	Demand Response
DS	Distribution Station
DVS	Dynamic Voltage Support
FIT	Feed-in-Tariff
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
NPV	Net-present value
MTS	Municipal Transformer Station
MVA	Megavolt ampere
Mvar	Megavolt ampere reactive
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TG	Transmission-connected Generation
TS	Transformer Station
TWG	Technical Working Group

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. In the past, 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.

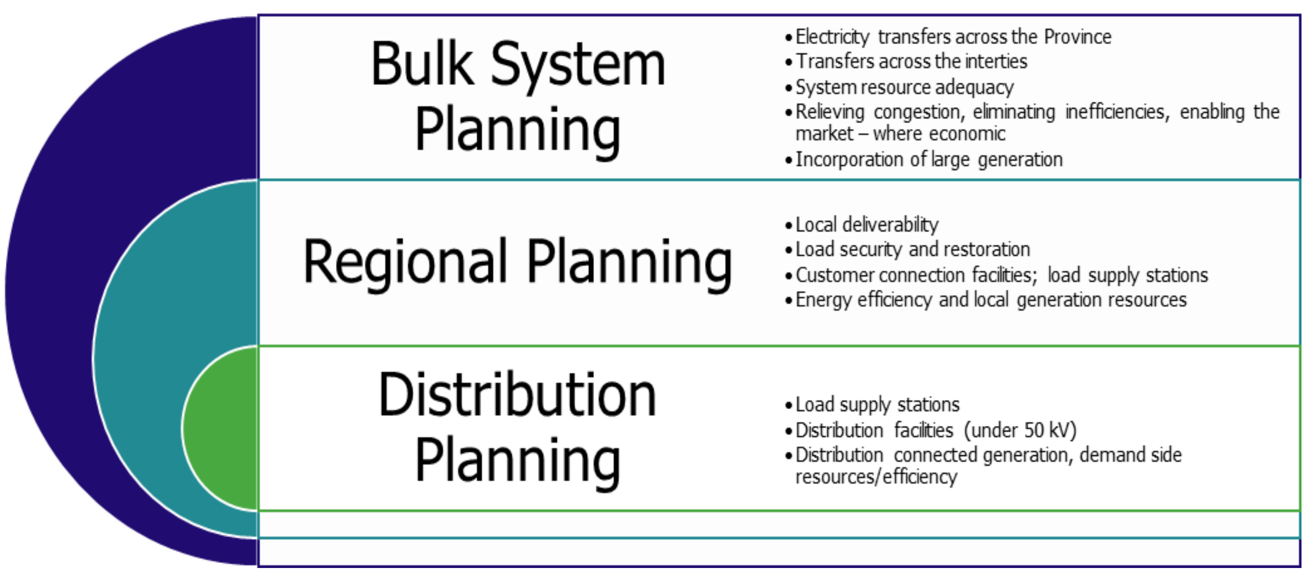
The final Needs Assessment Reports, Scoping Assessment Outcome Reports, IRRPs, and RIPs are posted on the IESO's and the relevant transmitter's websites, and may be referenced and submitted to the OEB as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments.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

This appendix describes the methodologies used to develop the peak demand forecast for the Burlington to Nanticoke 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 Forecast Starting Point Creation

The forecast starting point is the historical demand for a representative reference year (2022 for the Burlington to Nanticoke IRRP) on which LDCs build their gross demand forecasts.

A gross forecast means that existing and new DG, and new CDM savings are not accounted for in the forecast. Once DG and CDM are accounted for, they will reduce the gross forecast to produce a net demand forecast: the forecasted demand to be experienced by electricity system infrastructure. LDCs are asked to produce gross forecasts, because the IESO produces the DG and CDM forecasts. The DG forecast includes existing DG facilities up until their contracts expire, at which point they are removed from the forecast.

To produce the forecast starting point for LDCs, the IESO must first unbundle existing DG impacts from measured historical net demand, to produce historical gross demand, and then weather-normalize the historical gross demand. To produce historical gross demand, the historical hourly output of existing DG facilities[1] is added back onto the measured historical net demand of stations. The weather-normalization methodology is discussed in the next Section. For more information on producing the forecast starting point, please see Section 6.1 of the Load Forecast Guideline for regional planning, published by the Ontario Energy Board through the Regional Planning Process Advisory Group.

B.2 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., 2022 for the Burlington to Nanticoke 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

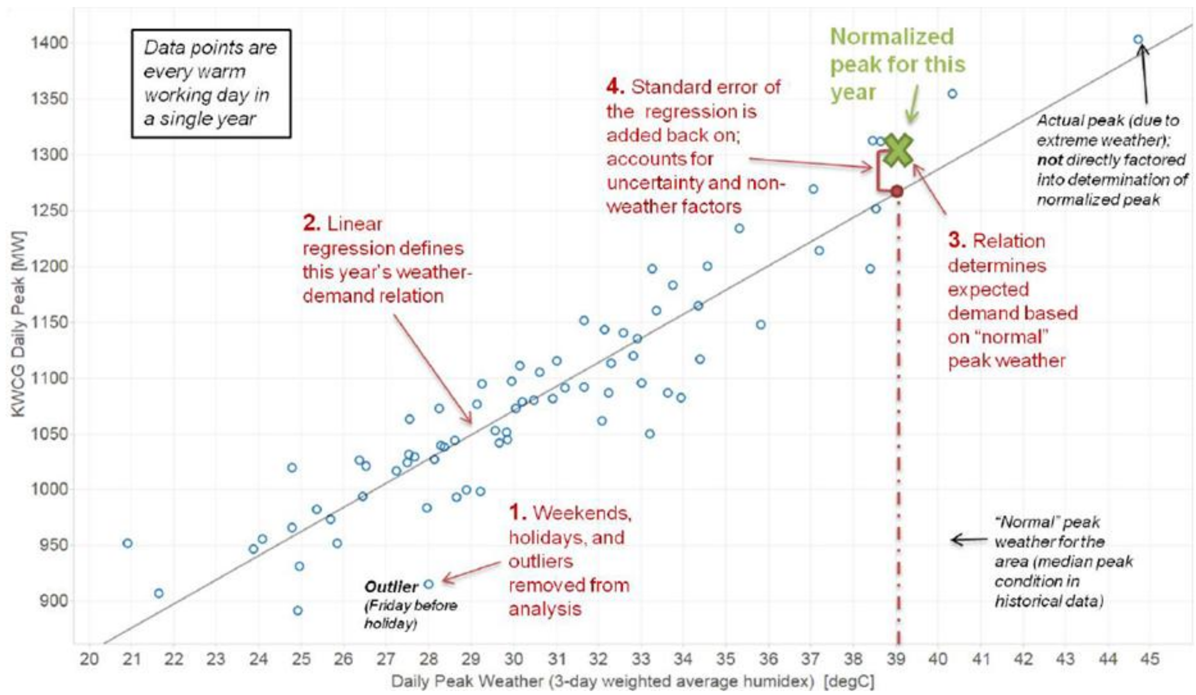
[1] When available, the measured hourly output of DG facilities is used; but if unavailable, the hourly output is estimated using the measured hourly capacity factors of aggregated facilities, and the installed capacity of the specific facility.

estimated 50% chance of exceeding this peak, and a 50% chance of not meeting this peak. The methodological steps are described in Figure 2.

The station-level 2022 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 – the 97th percentile. Peaks that occur during extreme weather (i.e., summer heat waves in southern Ontario) are generally when the electricity system infrastructure is most stressed.

Figure 2 | Method for Determining the Weather-Normalized Peak (Illustrative)



B.3 Alectra Utilities Corporation Forecast Methodology

Alectra Utilities Corporation supplies power to a portion of the Region through the following stations (in part or in whole): Beach TS, Birmingham TS, Dundas 1 TS, Dundas 2 TS, Elgin TS, Gage TS, Horning TS, Kenilworth TS, Lake TS, Mohawk TS, Nebo TS, Newton TS, Stirton TS, and Winona TS.

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.

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.

Electrification of Transportation

Alectra Utilities continues to monitor the uptake of electric vehicles (EV) and projects related to electrification of transportation to better understand and determine the impact on local electricity needs. Alectra Utilities uses the available information on EV adoption and evaluates the impact of the EV’s 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.4 GrandBridge Energy Inc. Forecast Methodology

GrandBridge Energy Inc. supplies power to a portion of the Region through the following stations (in part or in whole): Brant TS, Brantford TS, and Powerline MTS.

Expected residential housing development is a primary driving factor along with larger industrial development. These sectors have shown interest and purchased property both within Brantford and Brant County. With the annexation of 2,720 hectares of land from Brant County to the City of Brantford, there is an expectation of intense development in the north of Brantford.

Lump loads which included known residential subdivisions and planned permanent load transfers were used to forecast 2023-2026. Following that a historically assumed load growth rate of 1.2% was used until 2029. From 2030 onwards, a load growth rate of 4% is used to take into consideration the government's net zero/electrification targets.

B.5 Hydro One Networks Inc. (Distribution) Forecast Methodology

Hydro One Distribution supplies power to a portion of the Region through the following stations (in part or in whole): Bloomsburg DS, Brant TS, Caledonia TS, Dundas 1 TS, Dundas 2 TS, Jarvis TS, Nebo TS, and Norfolk TS.

Factors that Affect Electricity Demand

Hydro One Distribution serves the rural areas outside the major cities such as Burlington. The demand growth in the Hydro One Distribution service area is largely driven by the economic activities in these large communities and is expected to be modest as the population moves from the urban centers to the rural areas.

Forecast Methodology and Assumptions

The reference level forecast is developed using macro-economic analysis, which takes into account the growth of demographic and economic factors. The forecast corresponds to the expected weather impact on peak load under average weather conditions, known as weather normality. Furthermore, the forecast is unbiased such that there is an equal chance of the actual peak load being above or below the forecast. In addition, local knowledge, and information regarding the loading and developments in the area are utilized in developing the load forecast.

Hydro One Distribution used both econometric and end-use forecasting to develop the load forecast provided to the IESO. The main forecast drivers are Ontario GDP and housing starts. Load growth in the area relative to provincial trends and local information, including community/municipal energy plans from the City of Brantford, the County of Brant, the County of Norfolk, and the City of Hamilton, were also taken into account. Review of community energy plans indicated that they are consistent with Canada decarbonization policy. Electric vehicle and electrification assumptions are based on latest government mandates and initiatives.

B.6 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 Burlington to Nanticoke IRRP forecast are consistent with the energy efficiency assumptions in the IESO's 2024 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 Southwest IESO transmission zone and then allocated to the Burlington to Nanticoke Region. This section describes the process and methodology used to estimate energy efficiency savings for the Burlington to Nanticoke Region and provides more detail on how the savings for the two categories were developed.

B.6.1 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 Southwest 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, 2023 was used as the base year. New peak-demand savings from codes and standards were estimated from 2024 to 2042. 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 2042, the residential sector in the Region is expected to see about 6.1% peak-demand savings through codes and standards. The same is done for the commercial sector, which will see about 3.5% peak-demand savings through codes and standards by 2042. No codes and standards saving was assumed for the industrial sector. The sum of the savings associated with the two sectors is the total peak demand impact from codes and standards.

B.6.2 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. A top-down approach was used to estimate the peak demand reduction due to the delivery of these programs from the province to the Southwest zone, and finally to the stations in the Burlington to Nanticoke 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 the Southwest zone. They were then applied to the sectoral gross peak forecast of each station in the region. By 2042, the residential sector in the region is expected to see about 0.9% peak-demand savings through programs, while commercial sector and industrial sector will see about 9.4% and 3.6% peak reduction respectively.

B.6.3 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.

The CDM Forecast is provided in the Burlington to Nanticoke IRRP Appendix Excel as:

Table 1 | CDM (Codes and Standards + Energy Efficiency) Forecast, SUMMER

B.7 Installed Distributed Generation and Contribution Factor Assumptions

DG assumptions are provided in the Burlington to Nanticoke IRRP Appendix Excel as:

Table 2 Distributed Generation Contribution Factor Assumptions, SUMMER

Table 3 Total Contracted Distributed Generation (DG) Contribution to Peak, SUMMER

B.8 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 the Burlington to Nanticoke IRRP Appendix Excel as:

Table 4 Coincident Extreme Weather Net Station Peak Demand, SUMMER

Table 5 Non-Coincident Extreme Weather Net Station Peak Demand, SUMMER

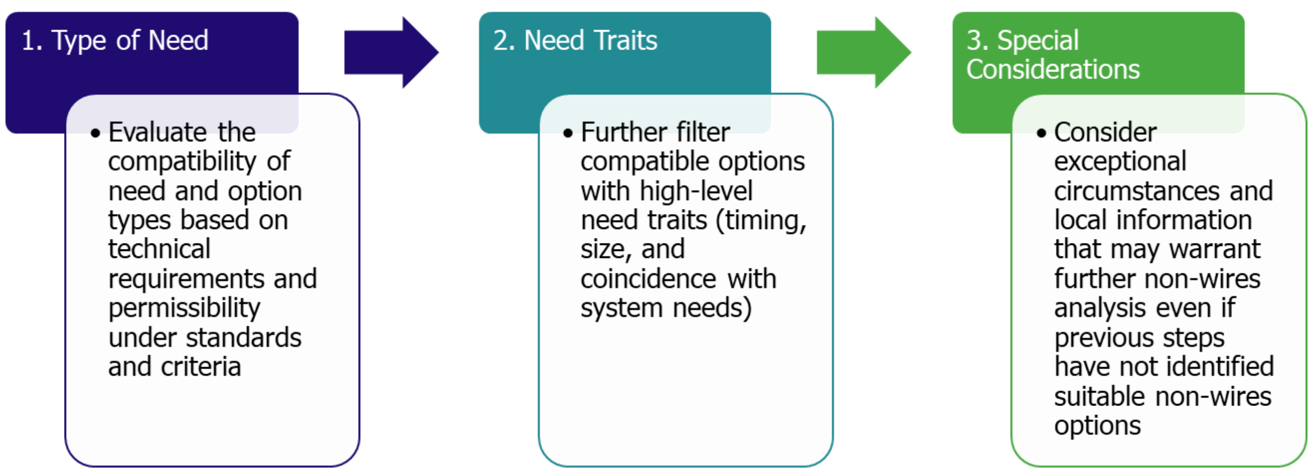
Appendix C IRRP NWA Screening Mechanism

The IESO developed a Guide to Assessing Non-Wires Alternatives (NWA), which is the current general approach used during IRRPs. This guide summarizes various recent improvements made to better consider NWAs when developing an IRRP, including the process flow diagram, screening mechanism, hourly needs characterization, development of options, and economic evaluation methodology. Planning participants and stakeholders can refer to this guide to better understand what key activities to expect during the IRRP.

An NWA screening step is carried out early in the IRRP development process after local reliability needs have been quantified but before options analysis begins. The screening mechanism provides a framework to identify suitable option types for the unique needs of each IRRP while improving transparency in the Technical Working Group's decision-making process, driving more consistency between different IRRPs, and focusing options analysis efforts on NWAs that are most likely to be feasible and cost-effective. The screening mechanism results in a shortlist of NWAs requiring further investigation. This list informs which local reliability needs require detailed hourly needs characterization, and maps candidate options to each need.

The screening mechanism is intended to be a guide rather than a strict set of criteria. It comprises three general steps that are summarized in Figure 3.

Figure 3 | IRRP NWAs Screening Mechanism



The first step in the screening mechanism is a general suitability filter that considers the type of need and the suitability of options according to its technical characteristics and permissibility under applicable planning criteria, such as the Ontario Resource and Transmission Assessment Criteria (ORTAC), North American Electric Reliability Corporation (NERC) TPL-001-4, and Northeast Power Coordinating Council (NPCC) Directory #1.

There are typically five types of needs identified through an IRRP: station capacity needs, supply capacity needs, asset replacement needs, load security needs, and load restoration needs. On the other hand, there are four categories of NWAs differentiated by operating characteristics (e.g. dispatchable vs. non-dispatchable), scalability, and treatment in current planning criteria. These include: transmission-connected generation or energy storage, CDM, distributed generation, and demand response. Table 6 is the matrix used for the first step in the screening. After a shortlist of the need type/option type combinations has been produced, the second step of the screening mechanism further reduces this shortlist by considering the need's high-level characteristics, such as the size of the need and the coincidence with system peak. Step 2 is summarized in Table 7.

Table 6 | Screening Step 1: Suitability by Need and Option Type

Option \ Need	Supply Capacity	Station Capacity	Asset Replacement	Load Security	Load Restoration
Transmission-connected Resources	Yes	No	Yes	No	Yes
CDM	Yes	Yes	Yes	No	No
Distributed generation	Yes	Yes	Yes	No	Yes
Demand response	Yes	Yes	Yes	No	No

Table 7 | Screening Step 2: Narrow Down Options Based on High-Level Need Traits

Option	Size of Need	Coincidence of the Need with System Peak
Transmission-connected Resources	Not applicable – always screened in	Always screened in – generation can likely provide system value during provincial peaks even if local need is not coincident
CDM	Screened in if need is less than 2% of the load forecast in each year	Screened in only if coincident with system peaks
Distributed generation	Screened in if need is less than the available distributed generation connection space	Always screened in – generation can likely provide system value during provincial peaks even if local need is not coincident
Demand response	Screened in if need is proportional to the historically offered amount of demand response in the capacity auction	Screened in only if coincident with system peaks

The third and final step of the screening mechanism does not include a set of criteria – rather, it is to recognize the flexibility in IRRPs for exceptional circumstances and the uniqueness of each region. In some cases, special considerations could warrant further NWAs analysis regardless of the screening steps and outcomes described above. To account for the uniqueness of each region, the Technical Working Group considers factors such as:

- Government policy or stakeholder support;
- Local preferences around solutions that the community will host;
- Unique load characteristics;
- Opportunities to explore a novel technology or operating model;
- Demand forecast uncertainty;
- Opportunities for integrated solutions; and,
- Availability of inexpensive and simple wires options that maximize the use of existing infrastructure.

Appendix D Hourly Demand Forecast

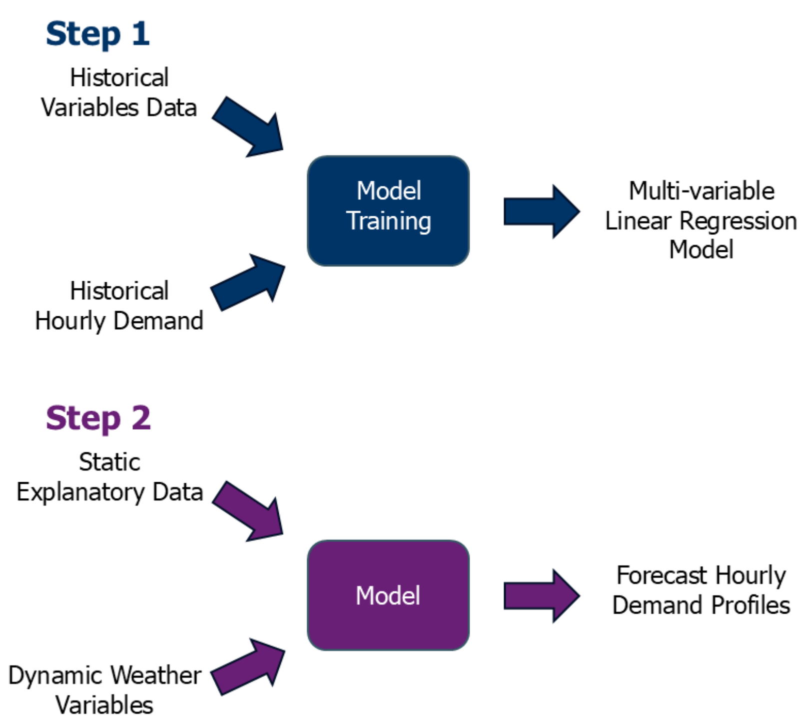
D.1 General Methodology

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 Burlington to Nanticoke IRRP, hourly load forecasting was completed on a station-level for stations with capacity needs, or for stations with upstream supply capacity needs, that were screened in from the IRRP NWA screening mechanism in Appendix C. This consisted of Bloomsburg DS and Norfolk TS.

Forecasting was completed using a multi-variable linear regression with approximately five years' worth of historical hourly load data. The two-step approach to hourly forecasting in IRRPs is summarized in Figure 4, and described further below.

Figure 4 | Summary of the Hourly Forecasting Methodology for IRRPs



First, a density-based clustering algorithm was used to filter the historical data for outliers (including fluctuations possibly caused by load transfers, outages, or infrastructure changes). Subsequently, the historical hourly data is combined with select predictor variables to perform a multi-variable linear regression and model the station's hourly load profile. The predictor variables are:

- Weather factors (temperature, cloud cover, humidity, and wind chill);

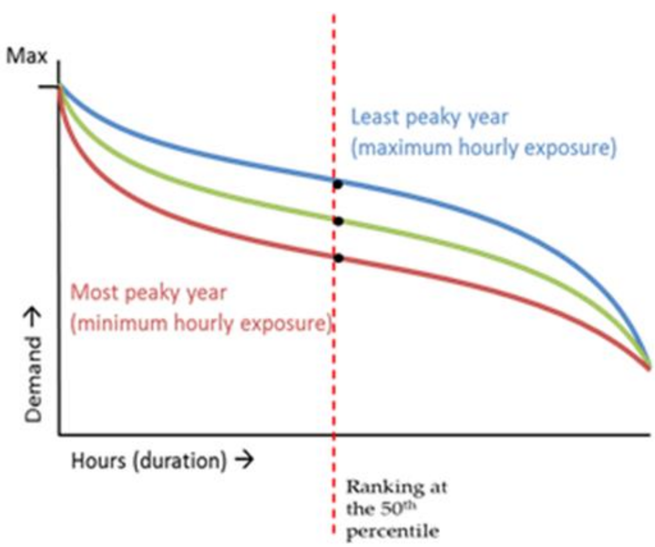
- Global horizontal irradiance;
- Econometric factors (population, employment);
- COVID-19 impacts; and,
- Calendar factors (holidays and days of the week).

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

To assess the impact that different weather sequences can have against the other non-weather variables (in particular, the calendar), a set of several possible future hourly weather forecasts is produced. To start, the historical hourly weather data from the past 31 years is recorded, producing 31 annual hourly profiles (each profile consists of 8760 hours, covering 1 year). Then, each of these 31 profiles is shifted both ahead and behind by up to seven days. This process generates an additional 14 new profiles from each of the previous 31 profiles. This approach ultimately leads to 465 (31 + 14x31) possible hourly weather forecasts for each future year. For example, the set of possible weather on June 2nd 2025 consists of the historical weather that occurred from every May 26th to June 9th over 1993 to 2023.

Subsequently, the set of 465 weather forecasts (together with the forecast of non-weather variables) are used to produce 465 load forecasts, which are ranked in ascending order based on their annual energy values. Load duration curves which illustrate this ranking can be seen in Figure 5. The forecast in the 50th percentile is the "Median Peak" (median profile, green curve), and is scaled so that its maximum matches the peak demand forecast.

Figure 5 | Illustrative Example: Ranking Hourly Load Profiles by Energy



Hourly forecasts are a direct input for further NWAs assessments when combined with the relevant local transmission limits. The shape of the forecasted load that exceeds transmission limits is referred to as the need profile, or energy-not-served. Need profiles help identify key characteristics – the magnitude, frequency, and duration of possible need events, and how they could be dispersed over the days, months, and years in the 20-year planning horizon.

Figure 6 and Figure 7 show monthly and hourly heat maps produced for Norfolk-Bloomsburg Area, Bloomsburg DS, and Norfolk TS to illustrate some of the capacity need characteristics in 2024. Each cell in the heat map indicates the expected frequency (percentage of time) of a capacity need (demand in excess of the LMC) according to the month or hour. Detailed information for these heat maps can be found in the Burlington to Nanticoke IRRP Appendix Excel file as:

Table 8 | Hourly Load Profiles and Hourly Need Profiles in 2042

To read the heat maps, for instance, it is estimated that loading in the Norfolk-Bloomsburg Area exceeds the LMC by 20 MW for roughly 41% of total hours in August 2042, as indicated in the top chart of Figure 6. Conversely, load levels are estimated to infrequently exceed the LMC by 20 MW in shoulder season months such as March, April, and May. This heat map also shows a significant need across all months of the year, with a need above 0 MW for at least 15%, and up to 87%, of hours in any month. From an hourly perspective, high magnitude needs greater than 20 MW will likely occur during the afternoon through evening hours, 2 PM – 10 PM, as shown in the top chart Figure 7. However, there is a significant need across all hours of the day, with a need above 0 MW for at least 17%, and up to 94%, of the time for any hour of the day.

For the Bloomsburg DS, it is estimated that its loading exceeds the LMC by 6 MW for roughly 11% of total hours in August 2042, as indicated in the middle chart of Figure 6. Conversely, load levels are estimated not to exceed the LMC by 3 MW outside of the summer months of: June, July, August, and September. This heat map also shows a significant need across the summer months of the year, with a need above 0 MW for at least 7%, and up to 29%, of hours in the summer months. From an hourly perspective, high magnitude needs greater than 6 MW will likely occur during the evening hours, 6 PM – 9 PM, as shown in the middle chart of Figure 7. However, there is a significant need across the evening hours, with a need above 0 MW for at least 18%, and up to 24%, of the time during the evening hours.

For Norfolk TS, it is estimated that its loading exceeds the LMC by 6 MW for roughly 2% of total hours in August 2042, as indicated in the bottom chart of Figure 6. Conversely, load levels are estimated not to exceed the LMC by 3 MW outside of the summer months of: July, August, and September. From an hourly perspective, needs will likely occur during the evening hours, 6 PM – 9 PM, as shown in the bottom chart of Figure 7.

Figure 6 | Monthly Heat Map of Norfolk-Bloomsburg Need Magnitudes in 2042

	Need (MW)	1	2	3	4	5	6	7	8	9	10	11	12
Norfolk-Bloomsburg Supply Capacity Need (MW)	70	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%
	60	0%	0%	0%	0%	0%	0%	1%	4%	0%	0%	0%	0%
	50	0%	0%	0%	0%	0%	1%	2%	9%	2%	0%	0%	0%
	40	1%	0%	0%	0%	0%	3%	6%	17%	6%	0%	0%	0%
	30	7%	2%	0%	0%	1%	7%	16%	28%	13%	0%	2%	1%
	20	22%	9%	2%	0%	2%	11%	28%	41%	23%	2%	9%	8%
	10	44%	26%	12%	3%	6%	19%	42%	63%	42%	15%	25%	26%
	0	74%	54%	35%	15%	15%	34%	62%	87%	72%	35%	49%	50%
Bloomsburg Station Capacity Need (MW)	15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	12	0%	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%
	9	0%	0%	0%	0%	0%	0%	1%	5%	1%	0%	0%	0%
	6	0%	0%	0%	0%	0%	1%	3%	11%	3%	0%	0%	0%
	3	0%	0%	0%	0%	0%	4%	7%	17%	6%	0%	0%	0%
	0	2%	0%	0%	0%	1%	7%	17%	29%	13%	0%	0%	0%
Norfolk Station Capacity Need (MW)	15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	12	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%
	9	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%
	6	0%	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%
	3	0%	0%	0%	0%	0%	0%	1%	4%	0%	0%	0%	0%
	0	2%	0%	0%	0%	0%	0%	1%	6%	1%	0%	0%	0%

Month

Figure 7 | Hourly Heat Map of Norfolk-Bloomsburg Need Magnitudes in 2042

	Need (MW)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Norfolk-Bloomsburg Supply Capacity Need (MW)	70	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%
	60	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	3%	2%	1%	0%	0%
	50	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	5%	8%	8%	6%	2%	0%	0%
	40	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	4%	10%	14%	15%	12%	7%	2%	0%
	30	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	2%	1%	1%	2%	3%	5%	10%	18%	32%	29%	24%	15%	7%	2%
	20	0%	0%	0%	0%	0%	0%	3%	7%	8%	6%	4%	5%	5%	8%	10%	16%	37%	53%	55%	40%	30%	17%	8%	1%
	10	10%	7%	4%	3%	3%	4%	7%	21%	32%	27%	19%	15%	15%	13%	18%	22%	34%	60%	73%	77%	68%	56%	39%	23%
	0	32%	25%	20%	17%	18%	21%	29%	53%	62%	56%	45%	35%	32%	29%	35%	41%	58%	80%	89%	94%	92%	85%	68%	51%
Bloomsburg Station Capacity Need (MW)	15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%
	12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	2%	1%	0%	0%	0%
	9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	4%	5%	3%	1%	0%	0%
	6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	6%	8%	10%	7%	3%	1%	0%
	3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	5%	10%	13%	16%	12%	8%	2%	0%
	0	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	2%	3%	5%	10%	18%	24%	24%	22%	14%	7%	2%
Norfolk Station Capacity Need (MW)	15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%
	9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%
	6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	2%	1%	0%	0%	0%
	3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	3%	2%	1%	0%	0%
	0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	5%	3%	1%	0%	0%

Hour

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 resources or transmission, 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.

The results of the 2019 APS were updated with the 2022 Achievable Potential Study ("2022 APS"). The 2022 APS shows that under the maximum achievable potential scenario, CDM measures have the potential to reduce summer electricity peak demand by up to 3,500 MW in the province over the 20-year forecast period and can produce up to 28 TWh of energy savings over the same period.

After scaling this level of forecasted maximum achievable savings potential to the local area, the forecast savings that are expected to come from existing provincial and federal CDM programs, the forecasted savings that are expected to come from future anticipated CDM programs, as well as from codes and standards, were netted out and the remaining achievable savings potential is identified. This remaining potential provides an estimate of the amount of incremental CDM savings potential that is available to help address emerging local needs in the Burlington to Nanticoke region.

E.1 Incremental Energy for the Burlington to Nanticoke Region

Based on the 2022 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 Southwest 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. Over time, new opportunities emerge with savings potential available across all sectors in this zone. Figure 8 illustrates the total maximum achievable savings potential in the Southwest zone according to segmentation (residential, commercial, and industrial).

Figure 9 to Figure 12 are obtained by applying these rates of savings potential to the demand forecasts for the stations in the Burlington to Nanticoke Region.

At Bloomsburg DS and Norfolk TS, shown in Figure 9, about 9.5 MW of CDM savings are available among customers connected to these stations in 2042. This 9.5 MW is also the magnitude of CDM savings available for the Norfolk-Bloomsburg Area (supplied by circuits C9+C12), since this area consists of these two stations. The estimated cost to deliver these savings is $35 million dollars over the forecast period based on APS cost assumptions.

At the Caledonia TS, shown in Figure 10, approximately 8.0 MW of uncommitted CDM savings potential is estimated to be achievable in 2042. The estimated cost to deliver these savings is $29 million dollars over the forecast period.

At the Brant TS and Powerline MTS, shown in Figure 11, approximately 18 MW of uncommitted CDM savings potential is estimated to be achievable in 2042. The estimated cost to deliver these savings is $68 million dollars over the forecast period.

For the Brant 115 kV Extended Area, shown in Figure 12, approximately 72 MW of uncommitted CDM savings potential is estimated to be achievable in 2042. The estimated cost to deliver these savings is $268 million dollars over the forecast period.

Figure 8 | Cumulative Maximum Achievable CDM in Southwest Transmission Zone as Share of Consumption

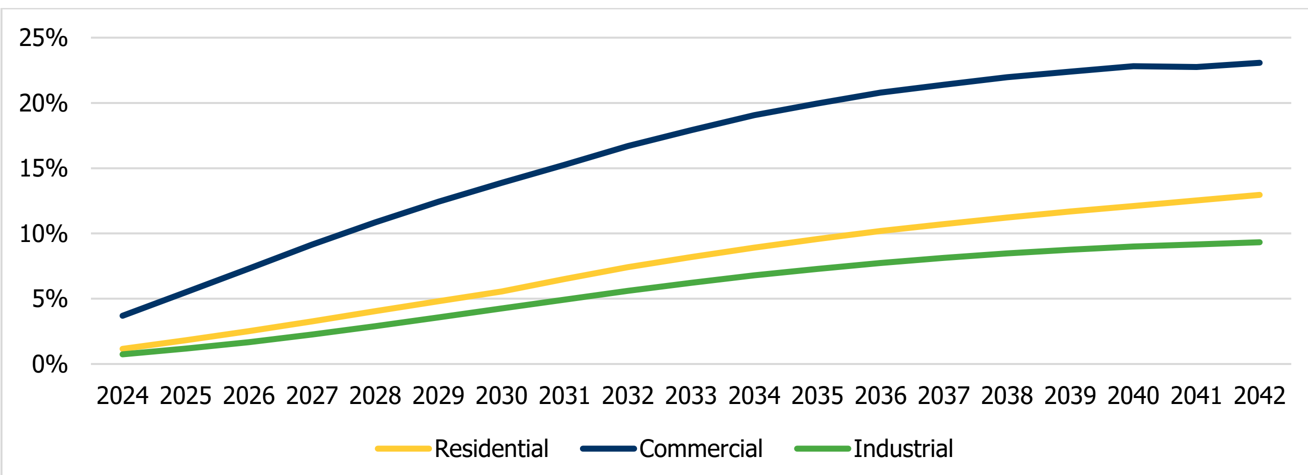


Figure 9 | CDM Potential at Bloomsburg DS and Norfolk TS

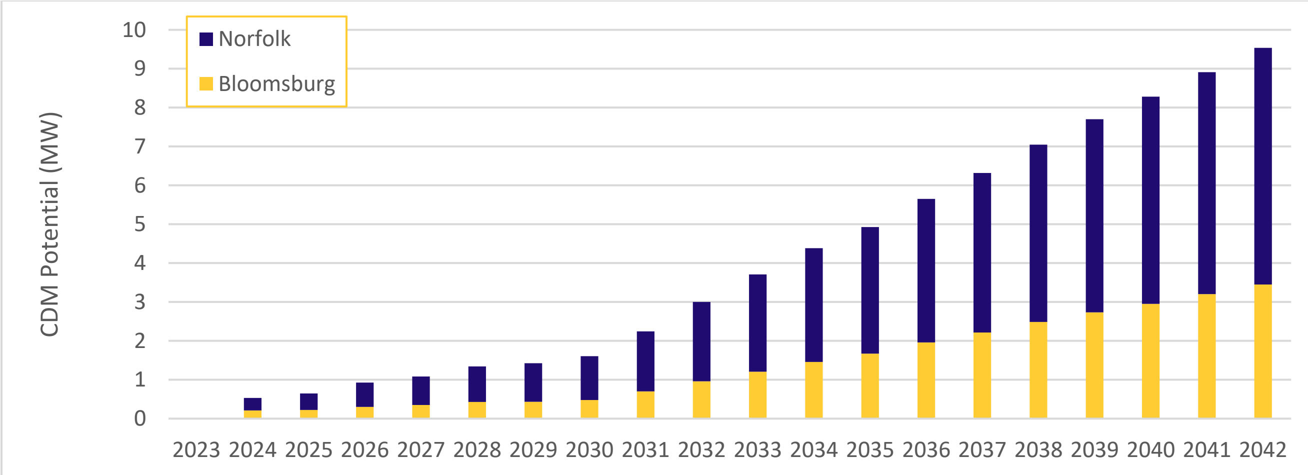


Figure 10 | CDM Potential at Caledonia TS

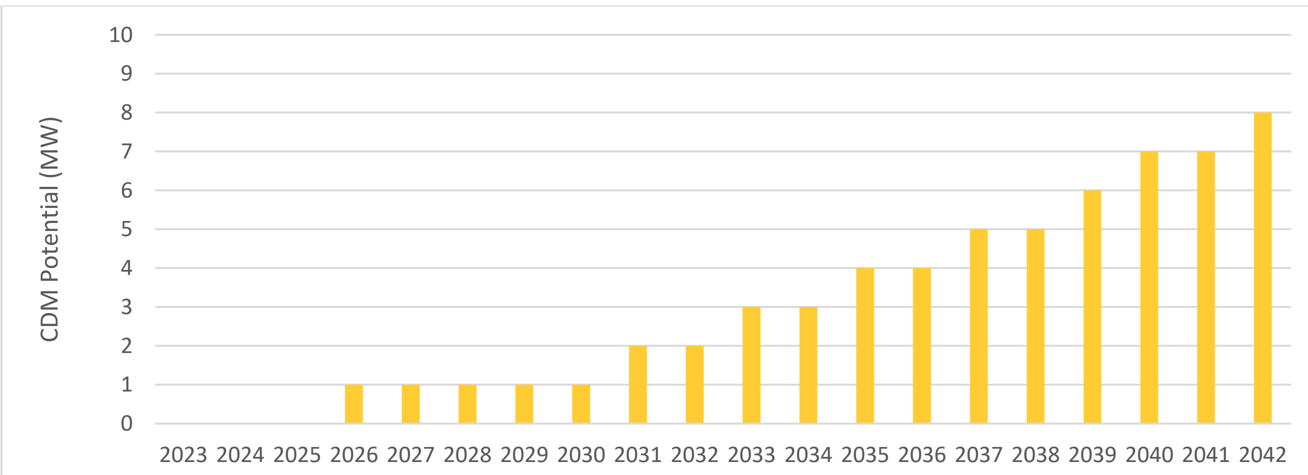


Figure 11 | CDM Potential at Brant TS and Powerline MTS

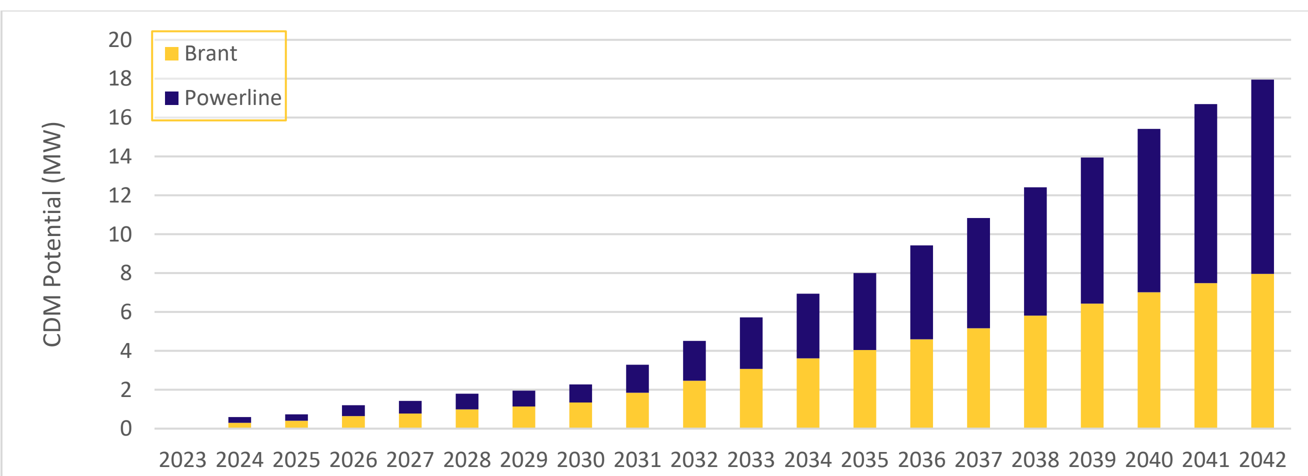
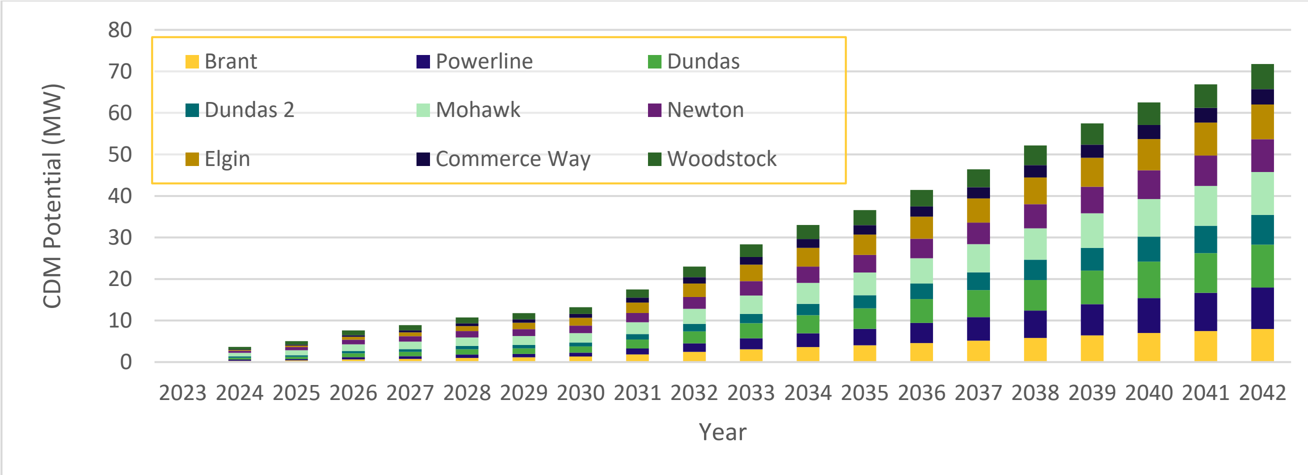


Figure 12 | CDM Potential in the Brant 115 kV Extended Area



Appendix F Economic Assumptions

The following subsections provide a list of the assumptions made in the economic analysis for options addressing needs. The overnight cost of capital was used when non-wires alternatives were found to be infeasible to address needs following the IRRP NWA Screening Mechanism described in Appendix C (e.g., in the Brant 115 kV Extended area).

F.1 General Assumptions

- The net present value (NPV) of the cash flows is expressed in 2024 CAD.
- The USD/CAD exchange rate was assumed to be 0.76 for the study period.
- The NPV analysis was conducted using a 4% real social discount rate. An annual inflation rate of 2% is assumed.
- The NPV study period for the long-term options analysis term extended from the start of 2035, the year that the solution would be in-service (worst case), to the end of 2104, when a transmission asset replacement decision would be required.
- 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.

F.2 Transmission Assumptions

- Capital costs for the transmission options were determined based on estimates of: $6-8M/km to either install a new double circuit 230 kV line or upgrade an existing double circuit 115 kV line to 230 kV; $5M/km to uprate existing 115 kV lines to higher ampacity lines; $30-50M/DESN for new 27.6 kV substation DESNs, and $60M per dynamic voltage support device (SVC, STATCOM, condenser). This was informed by cost estimates in the Leave to Construct application evidence on file with the Ontario Energy Board, benchmark transmission costs, as well as the input received from Hydro One. A -50% and +100% contingency was assumed for the purpose of this analysis.
- Short circuit limitations on the transmission system, which may impact the scope of work of resource options, were not assessed. For the Norfolk-Bloomsburg Area, the proposed medium-term BESS solution is assumed to be small enough so as not to encounter short circuit limitations.
- The life of the station assets was assumed to be 45 years; the life of transmission line was assumed to be 70 years.

F.3 Resource Assumptions

- The estimated levelized cost of capital and fixed operating costs assumed is $111,000/MW-yr (2024 CAD) for solar, $130,000/MW-yr (2024 CAD) for wind, and $330,000/MW-yr (2024 CAD) for battery storage. Costs are based on the 2023 National Renewable Energy Laboratory (NREL)

Annual Technology Baseline (ATB) Workbook publication, and accounts for the impact of the Clean Investment Tax Credit.

- 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 2023 National Renewable Energy Laboratory Annual Technology Baseline.
- Sizing of the battery storage solution was evaluated using load flow studies, discussed further in Appendix H.
- The magnitude of demand growth in this area exceeds the capability of energy efficiency or demand response to cost-effectively reduce the needs, and were therefore not considered as alternatives, but is considered further through ongoing regional planning in the area.

Appendix G Brant Subregion IRRP Technical Study

G.1 Description of Study Area

Needs for Brant subregion could not be identified in isolation due to its tight connectivity with the neighboring subregions. As such, the area of study was extended to the entire 115 kV system enclosed between the Burlington and Karn 115 kV stations, called the "Brant 115 kV Extended Area".

This Brant 115 kV Extended Area consists of the Brant and Powerline stations in the Brant subregion; the Woodstock, Commerce Way, and CTS6 stations in the Woodstock subregion of the London Area; and the Dundas, Dundas 2, Mohawk, Newton, Elgin, and CTS3 stations in the Hamilton subregion.

G.2 Study Methodology

Load flow transfer studies were conducted for various scenarios using the 2D transfer capability in the PowerTech VSAT program. In the VSAT 2D transfer studies, two independent sources/sinks can be defined to sweep a 2D plane and to determine their secure region of operation for the given contingency list and specified security/reliability criteria (outlined in the next section). A dependent source/sink should also be defined to balance the system as the two independent sources/sinks change.

For the purposes of the study, 2D load flow analysis was conducted with provincial generation as the dependent source and two independent sinks: 1) loads in the combined Brant and Hamilton 115 kV subsystems, and 2) loads in the Woodstock 115 kV subsystem.

For obtaining network LMCs, fictitious loads with a power factor of 0.9 were placed at the high-voltage side of the stepdown transformers or circuit junctions which were increased in the transfer studies while maintaining the values of the existing loads with a power factor of 0.95 within their station LMCs. With this approach, the network LMCs were obtained regardless of the connection arrangement and transformer ratings of new loads.

G.3 Criteria and Standards

Table 9 below summarizes the thermal criteria and standards used for these studies. Voltage criteria and standards are the same as those outlined in Section 4.2 and 4.3 of ORTAC.

All scenarios assume peak summer load conditions, consistent with the Planning Forecast. Note that the 115 kV system of the study area is neither BES nor BPS and respecting 115 kV double-element contingencies is not required. However, these contingencies were included to cover system planning under outage conditions for which separate studies would have been required otherwise. At the time the studies were started, the area of study did not have any local resource to be considered for outage studies and there was no adjustment available to take after the first outage.

Table 9 | Thermal Criteria and Standards – All Elements In-Service

Contingency[2]	Type	TPL/Directory 1 Event	Rating[3]	Maximum Allowable Load Loss
None	N-0	P0	Continuous	None
Single	N-1	P1, P2	LTE	150 MW by-configuration
Double	N-2	P7, P4, P5	LTE	600 MW by-configuration

G.4 Load Meeting Capabilities of Existing System

The results of the 2D transfer studies for the Brant 115 kV Extended Area are summarized in Table 10. Supply capacity limitations on the 115 kV subsystems are more restrictive than station capacity limitations; as a result, the LMCs of the stations could not be obtained for the existing system. However, assuming the required system reinforcements were made to resolve the supply capacity limitations (as discussed in Section G.5.1), then the resulting station LMCs are provided in Table 11. These represent the maximum demand that could be supplied from the stations by only considering the limitations of the existing station equipment.

Please refer to Sections 6.2 and 6.3 of the Burlington to Nanticoke IRRP Report for station and supply capacity needs, respectively, for the Brant 115 kV Extended Area resulting from these LMCs. Note the LMCs provided here are for reference and obtained from offline load flow planning studies which are more stringent than real-time operation. The real-time LMCs are expected to be larger based on favorable weather conditions and applicable standards and criteria in real-time operation.

Table 10 | Network Load Meeting Capabilities for the Existing Brant 115 kV Extended Area

Area	Summer LMC (MW)	Winter LMC (MW)	Post-Contingency Limitation
Brant 115 kV Subsystem	134	143	Thermal limitation on Burlington-Brant 115 kV circuit
Brant & Hamilton 115 kV Subsystem	500	-	Thermal limitation on Burlington-Brant 115 kV circuit
Woodstock 115 kV Subsystem	85	85	Voltage decline at Karn TS

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

[3] LTE: Long-term emergency rating. 50-hr rating for circuits, 10-day rating for transformers.

Table 11 | Station Load Meeting Capabilities for the Existing Brant 115 kV Extended Area

Subsystem	Station	Summer LMC (MW)
Brant	Brant	94
	Powerline	97
Hamilton	Dundas	98
	Dundas 2	83
	Mohawk	90
	Newton	78
	Elgin	125
	CTS3	46
Woodstock	Commerce Way	100
	Woodstock	89
	CTS6	37

G.5 Options Analysis

This section outlines the different options analysed to provide a permanent solution.

G.5.1 Reinforcements to the Brant 115 kV Extended Area

Initial transfer studies indicate a large deficiency in the supply capacity and the inability of the grid to serve the total demand forecast of the area of study due to various violations in different places. Therefore, 2D transfer studies were conducted in stages to identify all the supply capacity needs for serving demand at all stations up to their capabilities (provided earlier in Table 11). The most restrictive needs were identified at each stage and resolved by uprating sections of circuits with thermal violations or adding dynamic voltage support for voltage violations until all violations were resolved.

Table 12 and Table 13 summarize the reinforcements needed to the existing Brant 115 kV Extended Area to increase demand at all stations up to their capabilities. In summary, a total of 110 km of transmission line would need to be uprated by 3 times, and four dynamic voltage support devices rated for 100-150 Mvar each would be needed. The total cost of these reinforcements is estimated to be $750-800 M.

Despite reinforcements to the Brant 115 kV Extended Area, the station LMCs are inadequate to meet the demand in the Planning Forecast, as discussed in Section 6.2 of the Burlington to Nanticoke IRRP

Report. Additional investments would be needed to first increase station capacity, and then to further reinforce the Brant 115 kV Extended Area to increase its supply capacity.

This large expenditure for the 115 kV reinforcements in addition to the fact that this plan option is not capable of thoroughly resolving the needs in the long-term would be the reasons not to recommend this option.

Table 12 | Minimum Circuit Uprating Requirements for the Brant 115 kV Extended Area

Circuit	Length (km)	Uprating Factor
B12BL/B13BL – Burlington-Brant-Newton Circuits	51	1.5-2.5
B3/B4 – Burlington-Newton Circuits	28	1.0-1.5
B2 – Brant-Commerce Way Circuit	31	2.5-3.0

Table 13 | Minimum Circuit Uprating Requirements for the Brant 115 kV Extended Area

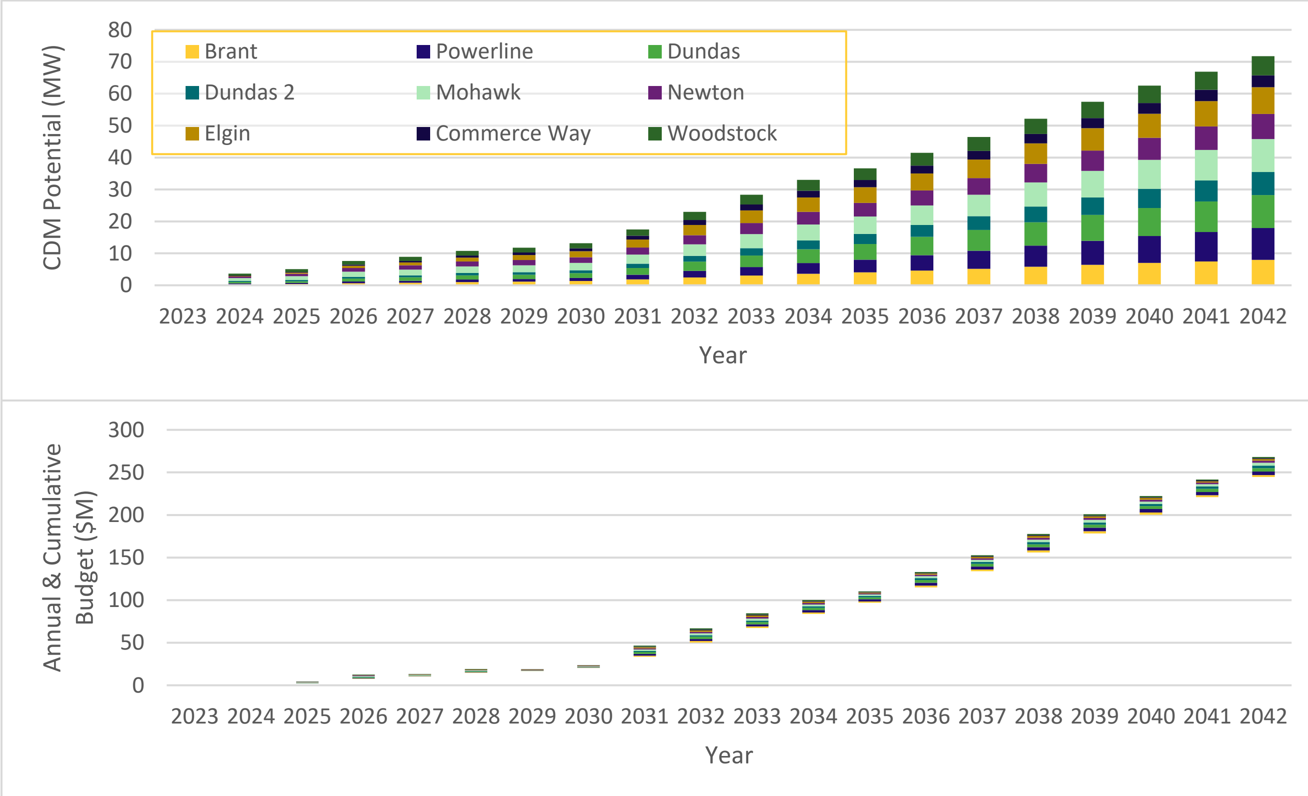
Station	Dynamic Voltage Support (Mvar)
Karn 115 kV TS[4]	2x150
Brant TS	100
Powerline MTS	100

G.5.2 Conservation and Demand Management

Figure 13 shows the potential CDM plus their annual and cumulative budgets for the Brant 115 kV extended area. Incremental CDM is not a viable option as it does not thoroughly resolve the needs or meaningfully reduce their magnitudes.

[4] Two units for dynamic voltage support were considered at Karn 115 kV TS not to lose the entire voltage support with a single outage.

Figure 13 | Uncommitted CDM Potential in the Brant 115 kV Extended Area



G.5.3 Local Resources

The optimal places to locate local resources are at the Brant and Newton stations, which are the receiving ends of the transmission system. Resources at these stations may relieve the loading on the 115 kV circuits. To identify the required generation capacities, 2D transfer studies were conducted with following assumptions.

- A pair of resources on the high-tension sides of the Brant stepdown transformers or the Newton stepdown transformers.
- The resources can continuously provide dynamic voltage support up to 33% of the rated capacity at any power output, as per Market Rules requirements.
- The loadings of the stations in the Brant and Hamilton subsystems are equal to their station capacities shown in Table 11.
- The total load in the Woodstock subsystem ranges from the 2023 load forecast (~100 MW) to its total station capacities shown in Table 6 (~225 MW).

The following is a summary of the load flow study results:

- The LMC of the Woodstock subsystem, with the voltage support from the local resources, increases to 130 MW. The limitation is thermal on B2 after the 230 kV supply from Karn TS is lost following the 230 kV double-circuit Middleport-Buchanan contingency. The local resources at Brant and Newton TS cannot resolve this limitation.
  Since the IRRP 20-year load forecast for the Woodstock subsystem does not exceed 130 MW, no

plan is required. Operational measures such as opening Brant 115 kV DB2 breaker is recommended if the subsystem net demand exceeds the limitation in real time.

- Minimum local resource requirements depend on the pre-contingency status of Brant DB2 breaker.
  - Brant DB2 breaker closed pre-contingency: local resources totaling at least 450-550 MW are required to resolve supply capacity needs of the Brant 115 kV Extended Area.
  - Brant DB2 breaker open pre-contingency: local resources totaling at least 600 MW are required to resolve supply capacity needs of the Brant and Hamilton 115 kV Subsystems.

This option is not recommended since building large, transmission-connected generation in densely populated urban areas, such as downtown Hamilton, is not feasible for the size required from non-emitting resources such as wind and solar generation. Additionally, BESSs were found infeasible due to insufficient charging capability. Due to the very limited load meeting capabilities of the system, there are times when off-peak charging of the BESS is not sufficient, resulting in the batteries being depleted for long peak periods. The demand on the Brant 115 kV Subsystem will quickly far exceed the LMC of the Subsystem, see Section I.4, leaving no capacity to sufficiently charge a large-scale BESS during off-peak hours.

G.5.4 Upgrading 115 kV System to 230 kV

This option was found to be infeasible since the 115 kV circuits pass through residential areas with a narrow right of way. Furthermore, the four-circuit tower arrangement of the 115 kV system in parts of the Hamilton area adds additional difficulties to conduct any upgrades. The cost of this option is also estimated to be prohibitively high, $1.0-1.5 billion.

G.5.5 New 230 kV Supply Connection Within the Brant 115 kV Extended Area

In this category of options, an additional 230 kV supply connection is provided to the Brant 115 kV Extended Area via new 230/115 kV autotransformers connecting within the area. The following three alternatives were studied.

- New 230/115 kV autotransformers connecting Brantford TS and the Alford junctions on B12BL & B13BL
- New 230/115 kV autotransformers connecting Brantford TS and Brant TS
- New 230/115 kV autotransformers connecting the Horning Mountain junctions on M27B & M28B (MxB) and Newton TS

Transfer studies indicate that a 230 kV supply connection would not resolve the supply capacity needs by itself and additional 115 kV or even 230 KV reinforcements would also be required, although not as extensive as those in Section G.5.1.

Nevertheless, studies indicate that none of these options are as effective as the solely reinforced 115 kV subsystem described in Section G.5.1. As such, this category of option is not recommended. The higher costs incurred for the pair of 230/115 kV autotransformers and due to the need to upgrade sections of 230 kV circuits in addition to 115 kV circuits is another reason not to recommend this type of option. The cost of this option is estimated to be $850-1,000 million.

G.5.6 Offloading the Brant 115 kV Extended Area to Existing/New 230 kV DESNs

In this category of options, the Brant 115 kV Extended Area is offloaded by transferring its loads to the existing or new 230 kV DESNs. Due to the magnitude of needs, each of the Hamilton 115 kV Subsystem and the Brant 115 kV Subsystem must be offloaded to keep demand within the Brant 115 kV Extended Area within its existing LMC. This is the recommended option.

Two alternatives were found readily available for offloading the Hamilton 115 kV Subsystem, since these 230 kV circuits pass adjacent to the Dundas stations.

- Transfer Dundas and Dundas 2 loads stations to new 230 kV DESNs connecting to Q23BM & Q25BM (QxBM) – not recommended, due to negative impact on the bulk Queenston Flow West transfer capability.
- Transfer Dundas and Dundas 2 loads stations to new 230 kV DESNs connecting to M27B & M28B (MxB) – Recommended Option, since the total forecasted load of both Dundas stations (~290 MW) can be served without the need to upgrade the 230 kV lines.

The following three alternatives were studied for offloading the Brant subsystem since these lines and the Brantford, Brant, and Powerline stations are all in the vicinity. Note that connection to M31W must be avoided, since the path is used to supply the existing loads and future growth along the path, at Ingersoll TS and the Woodstock 115 kV subsystem. Also note that with the recommended alternative, the Brant and Powerline loads would move to the KWCG region.

- Transfer Brant & Powerline loads to new 230 kV DESNs connecting to M32W & M33W (MxW) at Brantford TS – not recommended due to adverse impact on the bulk Buchanan Longwood Input/Negative Buchanan Longwood Input (BLIP/NBLIP) transfer capabilities and the need to upgrade the 230 kV circuits.
- Transfer Brant & Powerline loads to new 230 kV DESNs connecting to new junctions on MxW west of Newport Jct. – not recommended due to adverse impact on BLIP/NBLIP transfer capabilities and the need to upgrade the 230 kV circuits.
- Transfer Brant & Powerline loads to new 230 kV DESNs connecting to Galt Jct. on M20D & M21D (MxD) – Recommended Option. The ongoing KWCG regional planning will finalize this.

After the load served from the Brant, Powerline, Dundas, and Dundas 2 stations are transferred to new 230 kV DESNs, the remaining stations in the Hamilton 115 kV Subsystem (Mohawk, Newton, Elgin, and CTS3) can be loaded up to their capacities: a total of 339 MW. However, an additional 10-20 MW load increase would cause a supply capacity need to resurge.

As noted in Section 6.2 of the Burlington to Nanticoke IRRP Report, station capacity needs for the remaining stations in the Hamilton 115 kV Subsystem remain. Transferring their load to existing or new stations is required to avoid the resurgence of a supply capacity need, and consequently costly system reinforcements.

The total cost for this recommended option is estimated to be $200-300 M.

Appendix H Caledonia-Norfolk Subregion IRRP Technical Study

H.1 Description of Study Area

The Caledonia-Norfolk subregion was split into three study areas: the "Norfolk-Bloomsburg Area", the "Jarvis-CTS1 Area", and the "Nanticoke-Middleport 230 kV Path". Only the Norfolk-Bloomsburg Area had supply capacity needs identified, so it is the only study area discussed in this appendix. The Norfolk-Bloomsburg Area consists of the Norfolk and Bloomsburg stations in the Caledonia subregion.

H.2 Study Methodology

For the purposes of the study, 2D load flow analysis was conducted with provincial generation as the source and two independent sinks: 1) Norfolk TS, and 2) Bloomsburg TS. Note that the variable capacitors at Norfolk TS were taken out of service since they are used for correcting phase voltage imbalance induced on the circuits.

For obtaining network LMCs, fictitious loads with a power factor of 0.9 were placed at the high-voltage side of the stepdown transformers or circuit junctions. These were increased in the transfer studies while maintaining the values of the existing loads with a power factor of 0.95 within their station LMCs. With this approach, the network LMCs were obtained regardless of the connection arrangement and transformer ratings of new loads.

H.3 Criteria and Standards

Table 9 in Section G.3 summarizes the thermal criteria and standards also used for these studies. Voltage criteria and standards are the same as those outlined in Section 4.2 and 4.3 of ORTAC. All scenarios assume peak summer load conditions, consistent with the Planning Forecast. At the time the studies were conducted, the Norfolk-Bloomsburg Area did not have any local resource to be considered for outage studies and there was no adjustment available to take after the first outage.

H.4 Load Meeting Capabilities of Existing System

The results of the 2D transfer studies are summarized in Table 14. The supply capacity limitation on the 115 kV lines (C9+C12) is more restrictive than station capacity limitation on Norfolk TS; as a result, the LMCs of the station could not be obtained for the existing system. However, assuming the required voltage support was made to resolve the supply capacity limitation (as discussed in Section H.5.2), then the resulting Norfolk LMC is also provided in this table.

Please refer to Sections 6.2 and 6.3 of the Burlington to Nanticoke IRRP Report for station and supply capacity needs, respectively, for the Norfolk-Bloomsburg Area resulting from these LMCs.

Table 14 | Load Meeting Capabilities for the Norfolk-Bloomsburg Area

Station or Circuit(s)	Summer LMC (MW)	Winter LMC (MW)	Post-Contingency Limitation
Bloomsburg DS	37	40	Post-contingency thermal on step-down transformers
Norfolk TS	90	105	Post-contingency thermal on step-down transformers; C9+C12 LMC is limiting and must first be addressed
C9+C12	80	80	Post-contingency voltage decline on C9 or C12

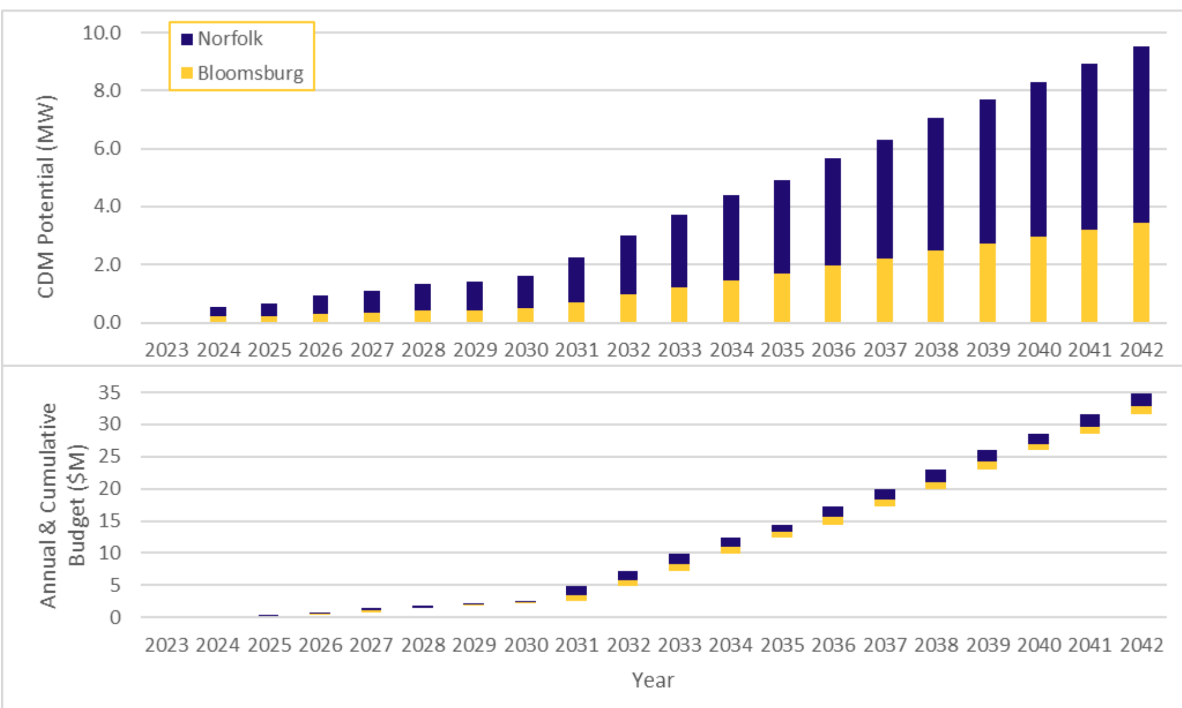
H.5 Options Analysis – Long-Term Needs

In the interim, it is recommended to open the bus-tie breakers at Bloomsburg DS and Norfolk TS, as necessary, to maintain post-contingency subsystem loads within the LMCs provided in the previous section. However, a permanent solution must be implemented as soon as possible, since this interim measure would reduce the load's reliability. This section outlines the different options analysed to provide a long-term solution.

H.5.1 Conservation and Demand Management

Figure 14 shows the potential CDM, plus the associated annual and cumulative budgets, for Norfolk TS and Bloomsburg DS. CDM is not a viable option as it does not thoroughly resolve the needs or meaningfully reduce their magnitudes. However, a combined option involving CDM is considered in Section H.5.3.

Figure 14 | Potential Conservation and Demand Management at Norfolk TS and Bloomsburg DS and the Associated Budget



H.5.2 Dynamic Voltage Support

Since the most limiting phenomenon in the Norfolk-Bloomsburg area is voltage decline/collapse at Norfolk TS, a dynamic voltage support (DVS) device (e.g. SVC, STATCOM or synchronous condenser) was added at the distribution-side at Norfolk TS to examine the largest LMC that can be achieved in the Area. Table 15 summarizes the results of the transfer studies where the dynamic voltage support device was set to provide up to 100 Mvar.

This option is not viable since it cannot thoroughly address supply capacity needs and only defers it to 2036. Also, it does not address station capacity needs. However, a combined option involving CDM is considered in the next section.

Table 15 | Load Meeting Capabilities for the Norfolk-Bloomsburg Area with New 100 Mvar Dynamic Voltage Support Device Replacing Capacitor at Norfolk TS

Station or Circuit(s)	Summer LMC (MW)	Winter LMC (MW)	Post-Contingency Limitation
Bloomsburg DS	37	40	Post-contingency thermal on step-down transformers
Norfolk TS	90	105	Post-contingency thermal on step-down transformers
C9+C12	150	150	Summer: Post-contingency thermal on C9 or C12 Winter: Post-contingency voltage decline on C9 or C12

H.5.3 Dynamic Voltage Support with CDM

The magnitude of the supply capacity need on C9+C12 can significantly be reduced with sufficient dynamic voltage support, as discussed in the previous section. The remaining need falls within the range of potential CDM values and the supply capacity need can be fully resolved.

Although the stations capacity needs would remain, their magnitudes are smaller. Transferring approximately 20 MW from the Bloomsburg and Norfolk stations to nearby stations such as Jarvis TS can resolve the station capacity needs. The cost of this option is estimated to be $100-200 M in NPV.[5]

From a technical perspective, this option meets supply and station capacity needs. However, the reliability of existing SVCs in the transmission system has been poor over the last five years. This may pose significant risk to the feasibility of this option.

Finally, although no supply capacity needs were identified for the Nanticoke-Middleport 230 kV Path, the need for capacity along this path is anticipated to support future decarbonization plans, data centre connections, and economic developments. However, capacity is bottlenecked for a highly loaded Norfolk-Bloomsburg Area, for example, a total load exceeding 50 MW for the existing system.

[5] The net-present value of each investment is needed when comparing non-wires to wires options, since non-wires options require incremental investments over time as resources are built as needed, whereas wires options require full buildout and investment up-front. The net-present value was calculated assuming a 70-year time horizon (typical life for transmission assets) and a social discount rate of 4%.

Therefore, it is reasonable to assume that in the long-term, the 115 kV Norfolk-Bloomsburg Area must be decommissioned because of its undesirable impact on the upstream 230 kV system. This would reduce the cost-effectiveness of the DVS device investments proposed in this option.

When considering the significant cost of this option, the questionable feasibility of the option (due to the reliability risk of DVS devices), and the anticipated likelihood of decommissioning the Norfolk-Bloomsburg Area in the long-term, this option is not recommended.

H.5.4 Transmission-Connected Generation – Long-Term Solution

To resolve the supply need using transmission-connected generation, a combination of solar generation, wind generation, and battery energy storage resources was considered. Due to policy considerations and decarbonization efforts, new natural gas-fired generation was not considered as a resource.

As discussed at the end of the previous section, capacity on the upstream 230 kV system is restricted for a highly loaded Norfolk-Bloomsburg Area. Because the need for capacity on the 230 kV system is anticipated in the long-term, and to better compare generation options with the wires options (that would remove all load in the Norfolk-Bloomsburg Area), this option required limiting the demand in the Norfolk-Bloomsburg Area to 50 MW.

Based on the hourly demand forecast produced (see Appendix D), 97% of hours in the year 2042 would exceed this 50 MW limit. Additionally, the excess demand would be fairly large, given a forecasted peak demand of 158 MW in 2042. Although a battery was considered in the resource mix, given the number of hours when demand would exceed the 50 MW supply limit, this battery could not be meaningfully charged by the grid (through supply circuits C9+C12). As a result, an excessive quantity of solar and wind resources would be needed to charge the battery, and a disproportionate quantity of battery storage would also be needed to reliably supply demand when intermittent resources are lacking (particularly overnight).

Given this consideration of the hourly needs of the Norfolk-Bloomsburg Area and the resulting implications on the required resources, upon further analysis through Step 3 of the NWA Screening Mechanism (see Appendix C), this option was screened out and is not recommended.

H.5.5 Upgrading 115 kV Circuits to 230 kV

Upgrading circuits C9+C12 from 115 kV to 230 kV is a feasible option, and based on the studies completed, the LMCs the 230 kV Nanticoke-Middleport Path exceed the amount of load forecasted within the next 20 years by a large margin. Note, however, that if a common-tower contingency becomes recognized because the 115 kV circuits are upgraded to a 230 kV double-circuit line, then the load meeting capability will be limited by the ORTAC load security criteria to 600 MW. The cost of this option is estimated to be $250-350 M in NPV.

Due to the higher cost, and because there is a better option to address the growth and economic developments in a wider area, described in Section H.5.8, this option is not recommended.

H.5.6 New 230 kV Double-Circuit Line – Extending NxJ to Norfolk

Extending the 230 kV NxJ circuits to the Norfolk-Bloomsburg Area was investigated as an option. However, based on the significant increase in CTS load forecasted, this option can only support demand until approximately 2030. Therefore, this option is not a viable long-term solution and is not recommended.

H.5.7 New 230 kV Circuits Tapping Off Nanticoke-Middleport Path

Building new 230 kV circuits tapping off the Nanticoke-Middleport 230 kV Path is a feasible option. Assuming circuits C9+C12 become idle following this option, this option has equivalent impacts as the earlier option presented in Section H.5.5, i.e. upgrading 115 kV circuits to 230 kV. However, this option is estimated to have a significantly lower cost than the previous option, as the tapping points can be relocated along the Nanticoke-Middleport 230 kV Path closer to the Norfolk-Bloomsburg Area. The cost of this option is estimated to be $150-200 M in NPV.

This option is not preferred in comparison to a similar alternative presented the next section. For this reason, this option is not recommended.

H.5.8 New 230 kV Double-Circuit Line from Nanticoke TS

Building a new 230 kV double-circuit line from Nanticoke TS into the Norfolk-Bloomsburg Area is a feasible option. In addition to resolving the supply and station capacity needs, this option can also support decarbonization plans, data centre connections, and economic developments in all three study areas (presented in Section H.1): the Norfolk-Bloomsburg Area, the Jarvis-CTS1 Area, and the Nanticoke-Middleport 230 kV Path. The new double-circuit line together with the existing NxJ circuits can serve up to 1,200 MW of load, including forecasted CTS expansion, without violating the ORTAC load security criteria.

The cost of this option is estimated to be $150-200 M in NPV. While the option presented in the previous section has a similar cost estimated, this option is preferred since it can address the needs for multiple areas, including possible growth due to industrial projects or AI/data centers in the vicinity of Nanticoke TS. This is the recommended option.

Note that it is imperative to offload the 115 kV C9+C12 circuits supplying the Norfolk-Bloomsburg Area. Otherwise as discussed at the end of Section H.5.3, the capability to connect new loads at Nanticoke TS or to the Middleport-Nanticoke 230 kV Path is significantly bottlenecked.

H.6 Options Analysis – Medium-Term Needs

In the interim, it is recommended to open the bus-tie breakers at the stations in the Area, as necessary, to maintain post-contingency subsystem loads within the applicable LMCs. However, a permanent solution must be implemented as soon as possible, since this interim measure would reduce the load reliability.

The previous Section recommended a permanent long-term solution; however, since the lead time of that solution is 7-10 years, a medium-term solution is needed until then. This section outlines the different options analysed to provide a medium-term solution.

There are fewer options in this section, because options must be limited to those which can be implemented in the medium-term, ahead of the recommended long-term solution. Additionally, options in this section were assessed against needs only up until 2034, since the long-term solution is expected to be in-service by 2035.

H.6.1 Dynamic Voltage Support

This option considers installing DVS devices at Norfolk TS which provide up to 100 Mvar of reactive power, similar to the long-term option considered in Section H.5.2. This would be sufficient to meet the supply capacity need up to 2034, as required for a medium-term option; however, station capacity needs would remain. Transferring approximately 20 MW from the Bloomsburg and Norfolk stations to nearby stations such as Jarvis TS can resolve the station capacity needs. The lead time of this option is estimated to be 2 years. The cost of this option is estimated to be $100-150 M in NPV.

From a technical perspective, this option meets supply and station capacity needs. However, as discussed in Section H.5.3, the reliability of existing DVS devices in the transmission system has been poor over the last 5 years, which jeopardizes the feasibility of this option.

Additionally, as discussed in Section H.5.3, it is anticipated that in the long-term the 115 kV Norfolk-Bloomsburg Area must be decommissioned because of its undesirable impact on the upstream 230 kV system. This would reduce the cost-effectiveness of the DVS device investments proposed in this option.

When considering the significant cost of this option, the questionable feasibility of the option (due to the reliability risk of DVS devices), and the anticipated likelihood of decommissioning the Norfolk-Bloomsburg Area in the long-term, this option is not recommended.

H.6.2 Battery Energy Storage System ("BESS") – Medium-Term Solution

This option considers the installation of a BESS, connected to transmission circuits C9+C12 near Norfolk TS, which also provides dynamic voltage support. This option may also include the installation of transmission-connected solar or wind generation, and/or additional CDM, if found to be more cost-effective by reducing the required BESS size. However, a BESS continuously providing dynamic support is the main component of this solution.

Similar to the previous option, this option would be sufficient to meet the supply capacity need up to 2034, as required for a medium-term option; however, station capacity needs would remain. Transferring approximately 20 MW from the Bloomsburg and Norfolk stations to nearby stations such as Jarvis TS can resolve the station capacity needs.

The IESO expects that this option is cost-competitive and potentially could be lower-cost when compared to the wires alternative; however, detailed studies are needed. This is particularly true when considering that the BESS sizing (in rated capacity (MW) and energy (MWh)) is dependent on the rated reactive power (Mvar) of the BESS. However, in order to procure this BESS to meet local needs, rather than provincial needs, the IESO may need to consider developing a new procurement process to implement this option. And to prevent biasing the project costs submitted by applicants into any future process, the IESO is unable to provide the cost range for this option.

The lead time for this option is estimated to be 4-6 years, including the potential time needed to develop a new procurement process, if required.

As an additional consideration, unlike the previous option, this option continues to provide value after the long-term solution is in place. This is because the BESS can continue to operate for the remainder of its life to meet the capacity needs of the provincial grid, even after the C9+C12 circuits are entirely offloaded. Last, feedback from Norfolk County expressed support for a resource solution to meet medium-term needs.

For these reasons supporting this option, and for the reasons against the alternative option discussed in the previous section, this option is recommended to address medium-term needs.

Appendix I Figures of Station and Supply Capacity Needs

The following graphs provide a comparison between the summer forecasts and load meeting capabilities at stations or areas/subsystems where a need was identified. The non-coincident extreme weather net peak demand forecasts are used for the stations and coincident extreme weather net peak demand forecasts for the areas/subsystems.

I.1 Station Capacity Needs in the Brant Subregion

Figure 15 | Station Capacity Need for Brant TS

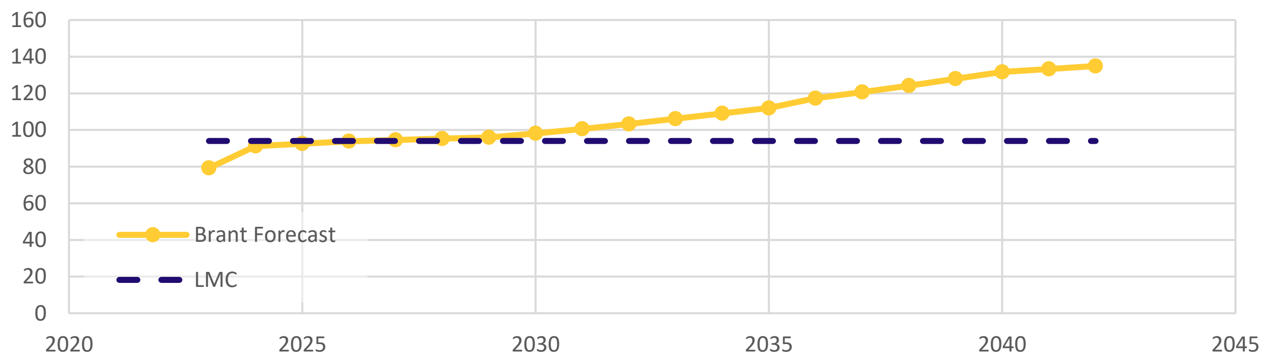


Figure 16 | Station Capacity Need for Powerline MTS

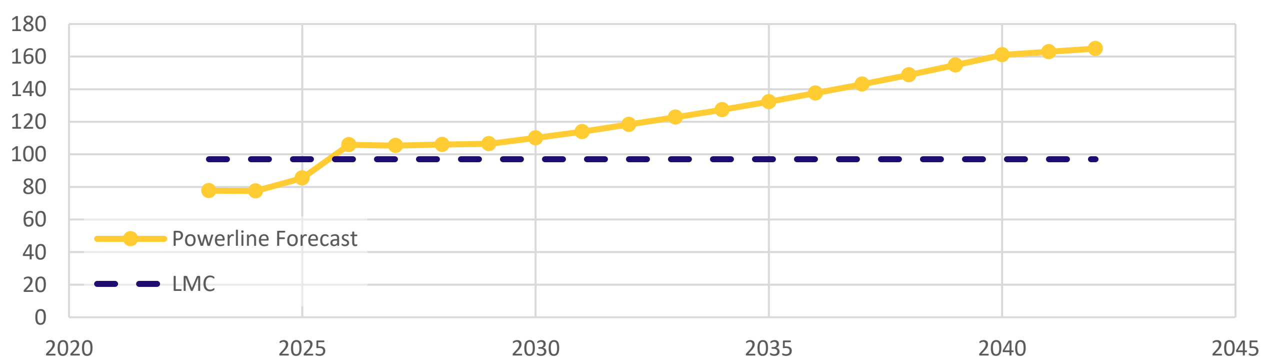
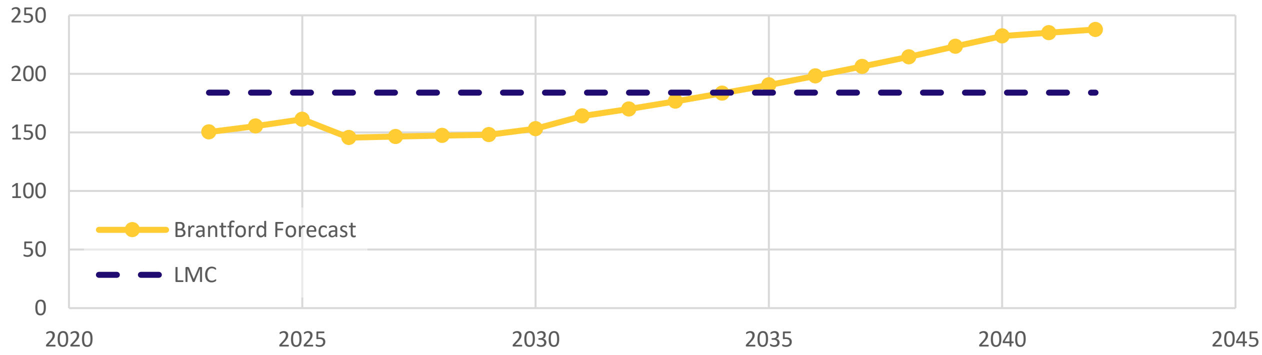


Figure 17 | Station Capacity Need for Brantford TS



I.2 Station Capacity Needs in the Caledonia-Norfolk Subregion

Figure 18 | Station Capacity Need for Norfolk TS

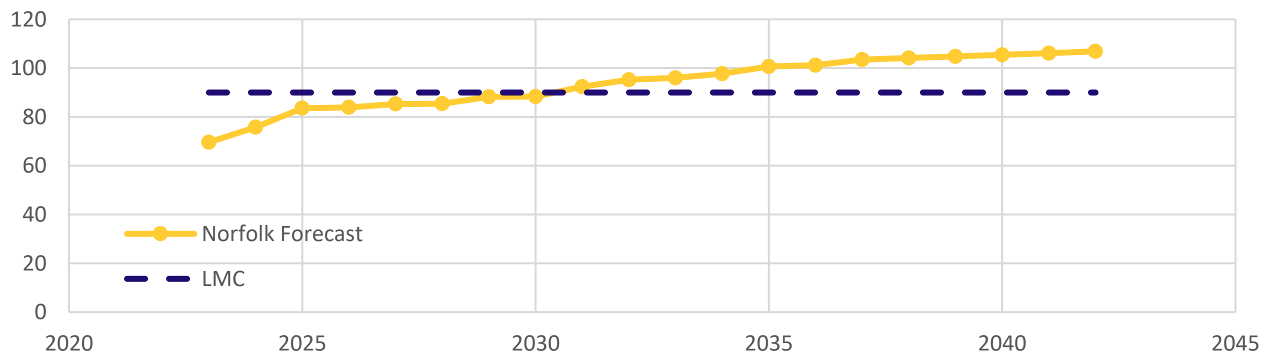


Figure 19 | Station Capacity Need for Bloomsburg DS

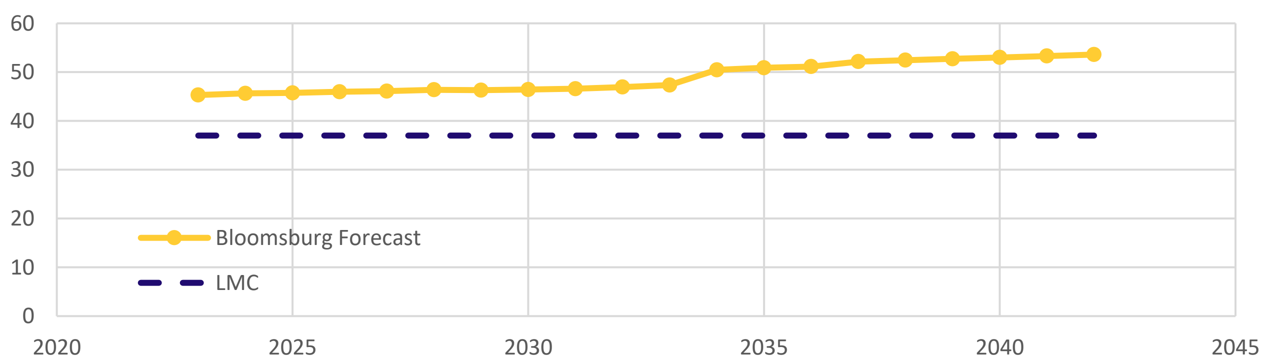
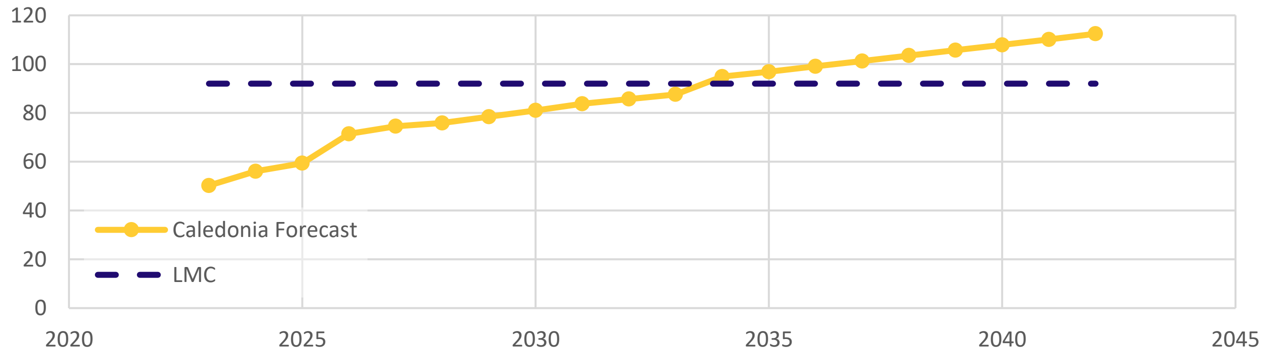


Figure 20 | Station Capacity Need for Caledonia TS



I.3 Station Capacity Needs in the Hamilton Subregion

Figure 21 | Station Capacity Need for Dundas TS

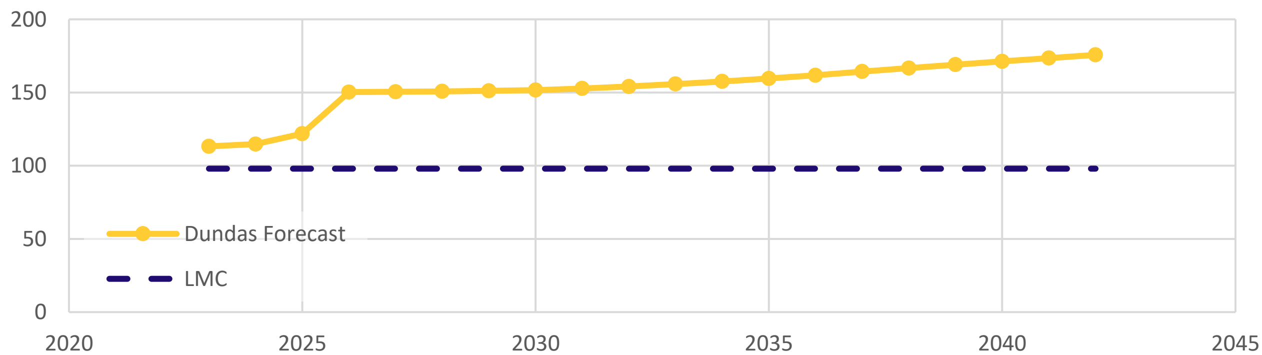


Figure 22 | Station Capacity Need for Dundas 2 TS

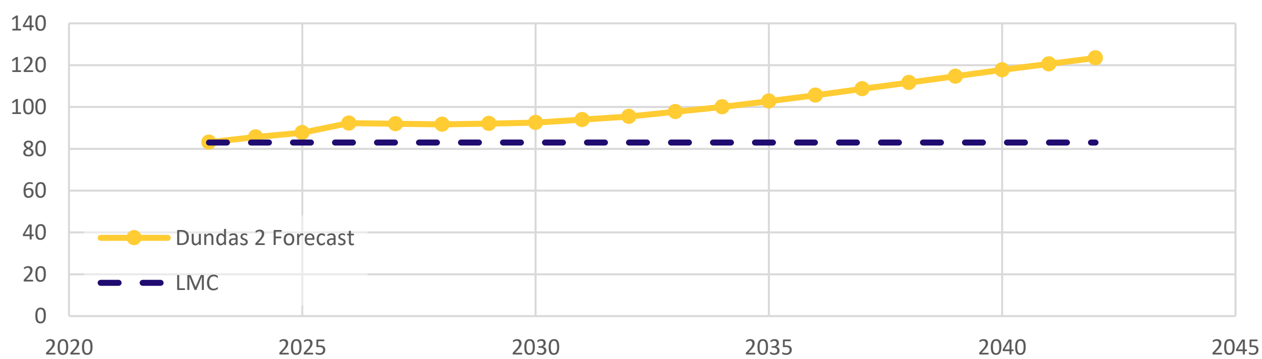


Figure 23 | Station Capacity Need for Mohawk TS

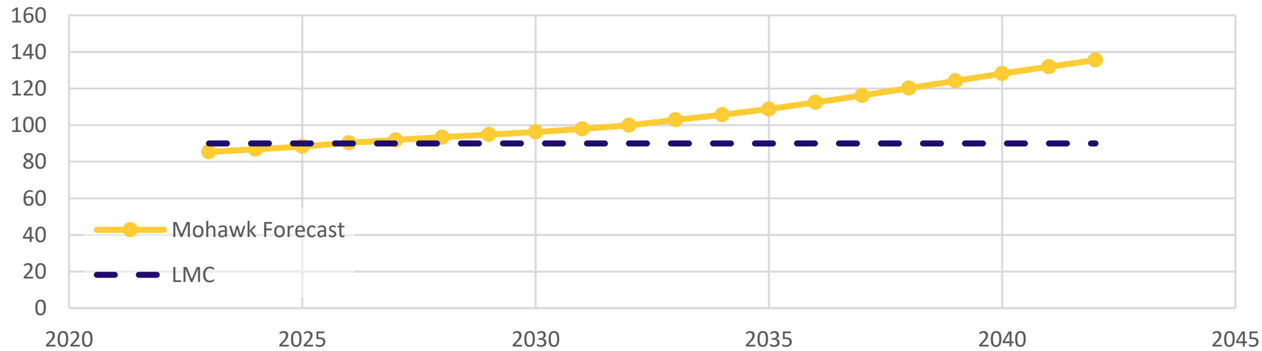


Figure 24 | Station Capacity Need for Elgin TS

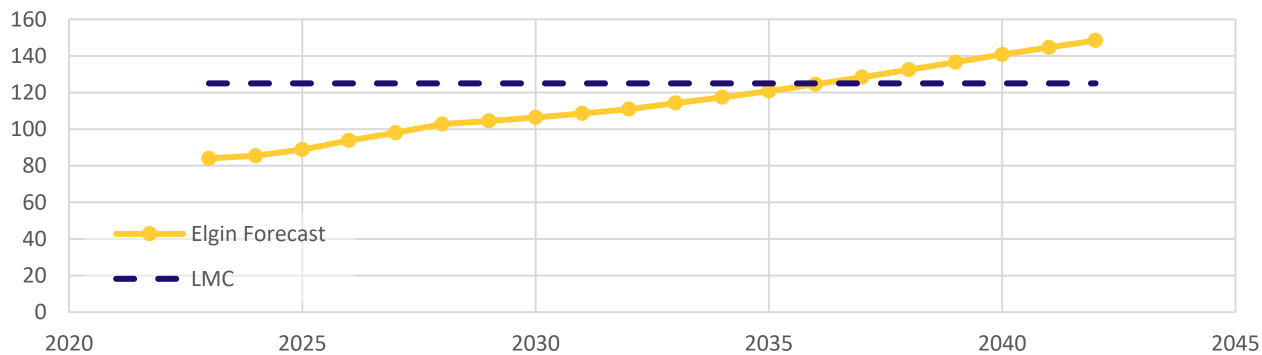


Figure 25 | Station Capacity Need for Newton TS

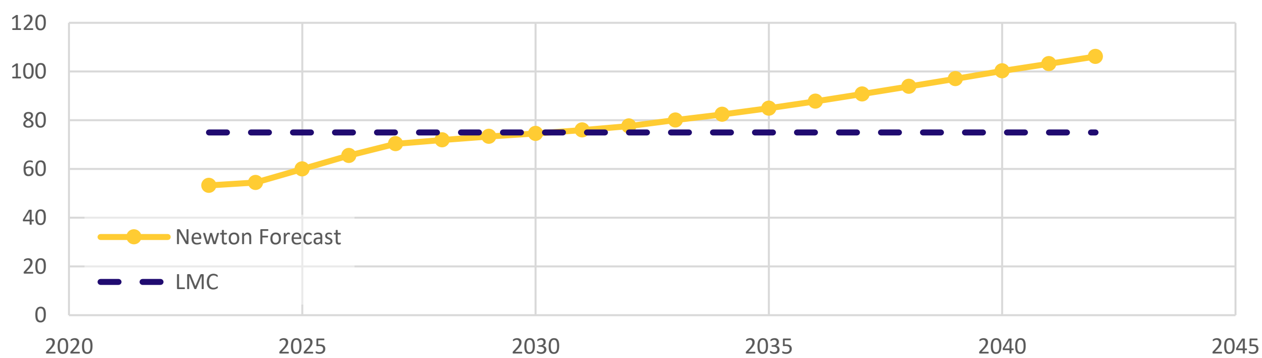


Figure 26 | Station Capacity Need for Horning TS

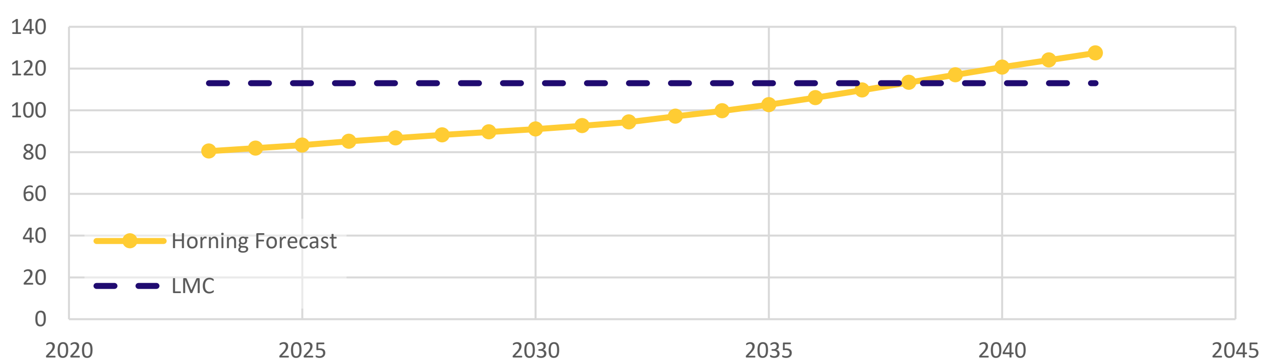


Figure 27 | Station Capacity Need for Nebo TS (T1/T2)

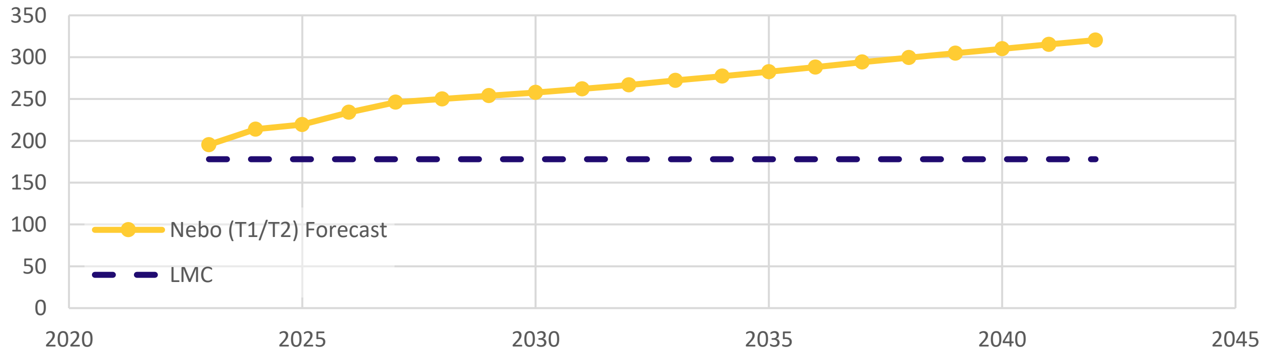


Figure 28 | Station Capacity Need for Nebo TS (T3/T4)

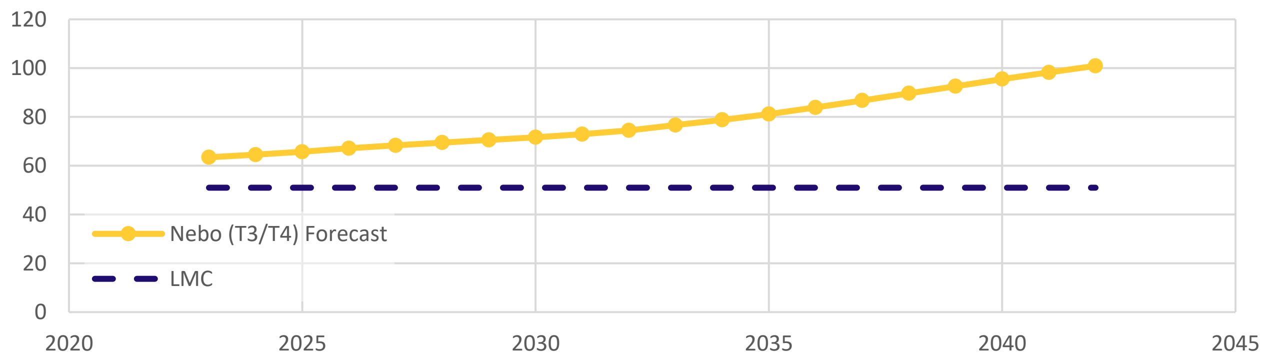


Figure 29 | Station Capacity Need for Lake TS

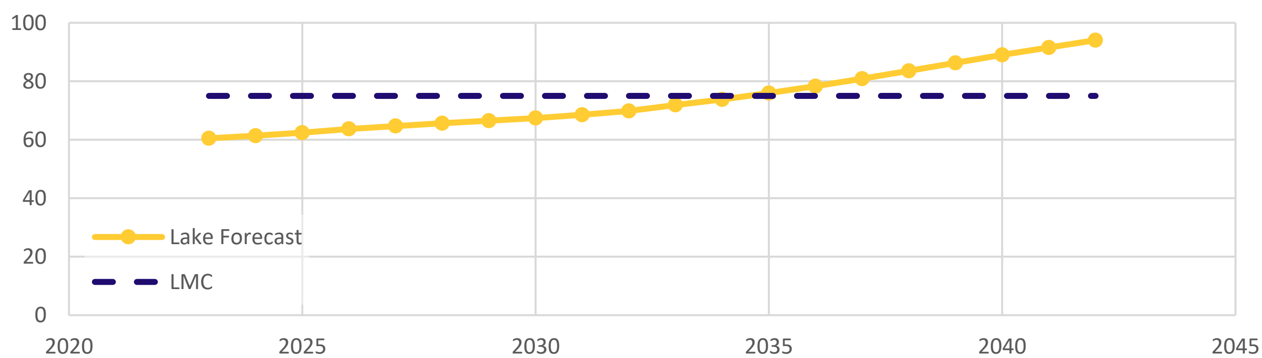


Figure 30 | Station Capacity Need for Beach TS

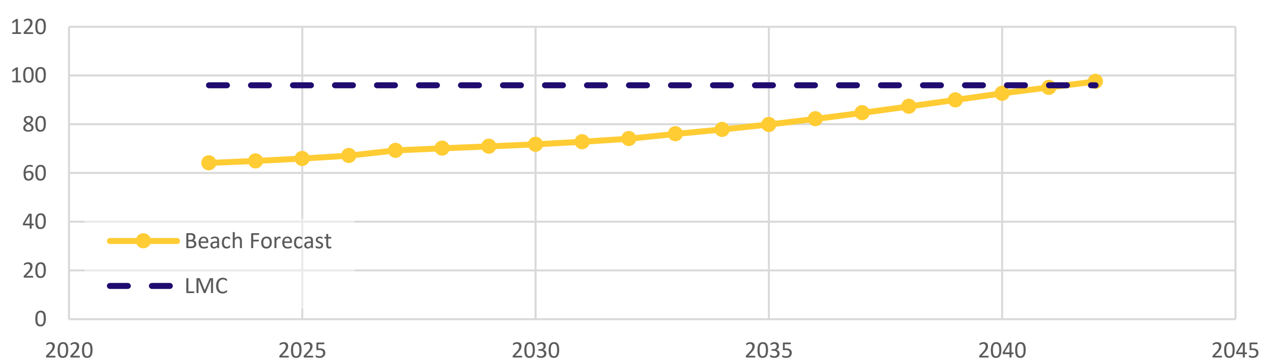
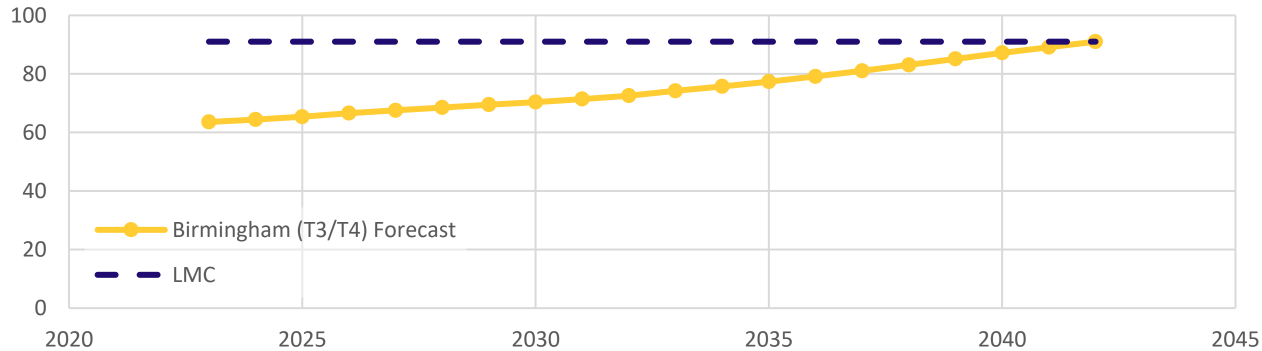


Figure 31 | Station Capacity Need for Birmingham TS (T3/T4)



I.4 Supply Capacity Needs

Figure 32 | Supply Capacity Need for the Brant 115 kV Subsystems

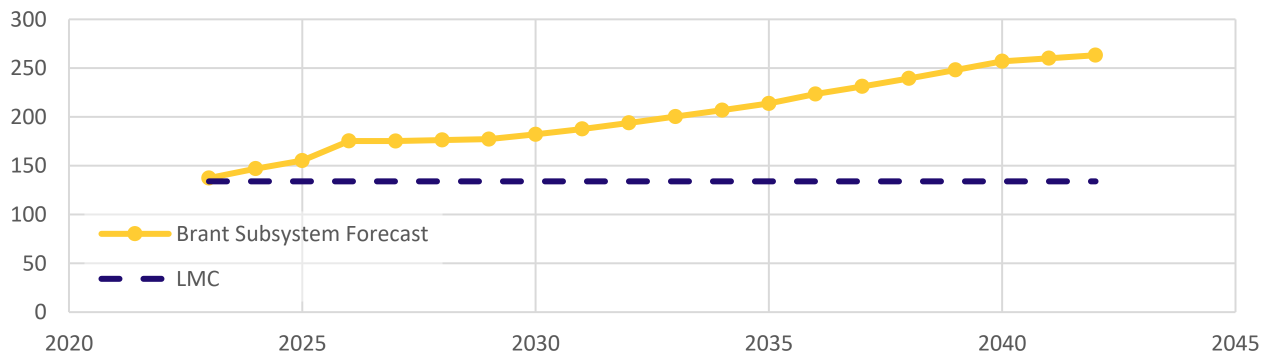


Figure 33 | Supply Capacity Need for the Combined Brant and Hamilton 115 kV Subsystems

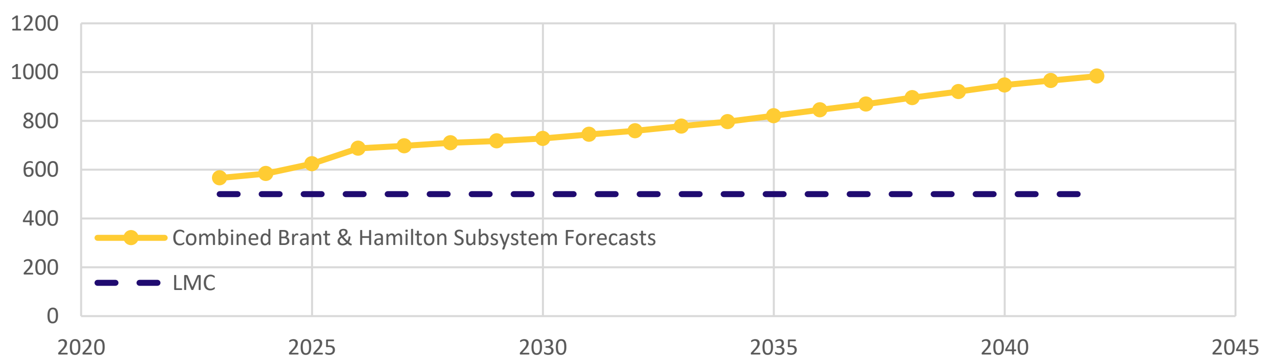


Figure 34 | Supply Capacity Need for the Woodstock 115 kV Subsystems

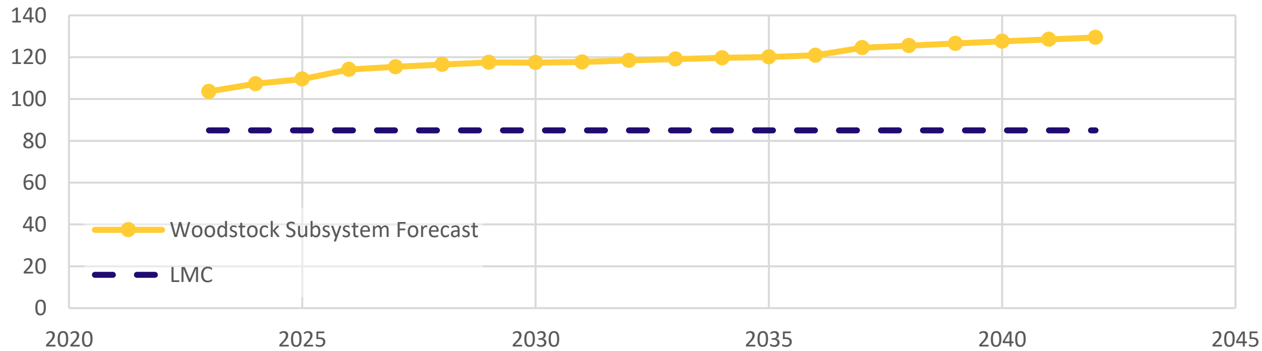
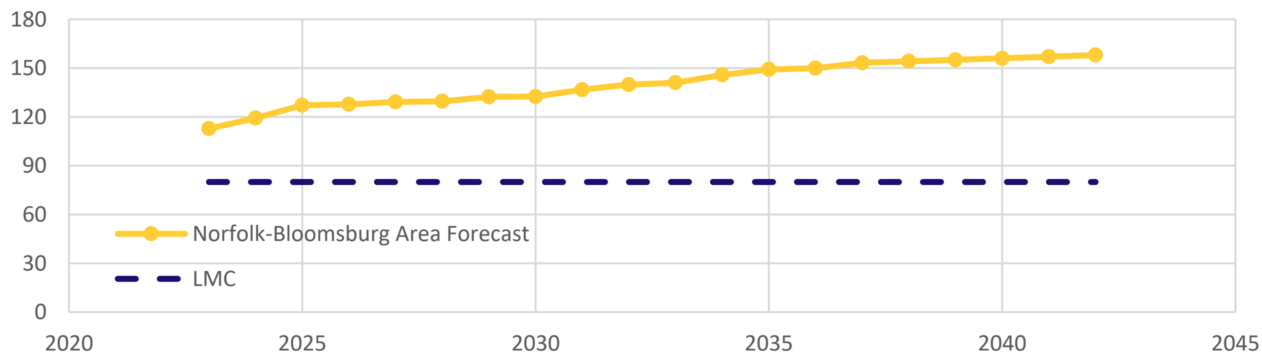


Figure 35 | Supply Capacity Need for the Norfolk-Bloomsburg Area



Appendix J Hamilton Area Addendum Scope of Work

J.1 Overview

The Hamilton Area Addendum launched on February 05, 2026 and will be completed over a 12-month period. The primary focus of the Addendum will be on addressing needs in the Hamilton sub-region, identified in the 2024 Burlington to Nanticoke IRRP. The Hamilton sub-region consists of the 115 kV supply southwest from Burlington TS and the 230 kV supply from Beach TS which service the 115 kV network in the Hamilton subregion, while 230 kV circuits between Burlington TS and Beach TS, Beach TS and Middleport TS, and Middleport TS and Burlington TS supply the Hamilton subregion's 230 kV connected load supply stations.

Figure 36 | Map of Hamilton Area Addendum

J.2 Needs to be Addressed

The Addendum will develop and recommend an integrated plan to meet the needs of the Hamilton sub-region. The plan is a joint initiative led by the IESO and completed by the members of the Technical Working Group (TWG) – Alectra Utilities Inc., Hydro One Distribution, GrandBridge Energy

Inc.[6], Hydro One Transmission, and the IESO. Burlington Hydro Inc. and Oakville Hydro Electricity Distribution Inc. supply loads within the Burlington to Nanticoke Region, but not within the Hamilton sub-region. As a result, Burlington Hydro Inc. and Oakville Hydro Electricity Distribution Inc. will be kept informed and included as optional attendees for TWG meetings.[7]

The plan will consider the demand forecast for the region, the CDM, DER uptake, transmission, and distribution system capabilities, and align with relevant community plans, bulk system developments, and policy direction as applicable.

The Hamilton Area Addendum aims to address the following needs that have currently been identified:

Table 16 | Needs to be Assessed in the Hamilton Area Addendum

Station/Circuit	Description of Need	Timeline	Priority Area
B10/B11	Supply Capacity	Near-term	Bayfront Industrial Area
Mohawk TS	Station Capacity	Near-term	
Nebo TS (T1/T2)	Station Capacity	Near-term	South of Hamilton
Nebo TS (T3/T4)	Station Capacity	Near-term	South of Hamilton
Lake TS (T1/T2)	Station Capacity	Medium-term	
McMaster TS	Station Capacity	Medium-term	
Newton TS	Station Capacity	Medium-term	Newton
Beach TS (T5/T6)	Station Capacity	Long-term	
Elgin TS	Station Capacity	Long-term	
Horning TS	Station Capacity	Long-term	

J.2.1 Priority Needs

The TWG has identified three priority need areas to be addressed first within the Addendum, corresponding to the needs identified in Table 16.

[6] Although GrandBridge Energy Inc. does not supply loads in the Hamilton sub-region, GrandBridge Energy Inc. is included in the TWG to coordinate with recommendations made for the Brant Extended Area.

[7] Needs at Bronte TS have been identified, which affect Burlington Hydro Inc. and Oakville Hydro Electricity Distribution Inc. However, solutions for Bronte TS will be assessed and recommended in the GTA West IRRP. This because there is stronger coordination between Bronte TS and the stations in the GTA West IRRP; and, because the GTA West IRRP is presently assessing solutions, which will allow for an earlier recommendation for Bronte TS if included in the GTA West IRRP.

1. **Bayfront Industrial Area**

   Hamilton's Bayfront Industrial Area is seeing a large increase in requests for new electrical demand driven by new large industrial customers, potential largescale data centres, and substantial growth from existing industrial customers. The magnitude of this load growth results in considerable station and supply capacity needs in the area. An integrated approach is necessary to address these needs and enable additional supply capacity for the area.

2. **South of Hamilton**

   Significant growth is forecast in southern Hamilton near the airport and in Ancaster, resulting in a station capacity need at Nebo TS. Coordinated solutions will be considered to address this need while alleviating constraints at Caledonia TS and Dundas/Dundas #2 TSs.

3. **Newton**

   Strong residential, commercial, and industrial growth in the northwest of urban Hamilton are resulting in station capacity needs at Newton TS. Alectra Utilities Inc. has indicated limited opportunities to transfer load to nearby stations, and financial considerations limit the feasibility of station upgrades.

J.3 Coordination with Other Plans

In parallel with the Hamilton Area Addendum, there are three electricity plans that will require close coordination. The IESO is currently undertaking the London Area IRRP and will be launching the Niagara Bulk Plan in Q1 2026. Additionally, Hydro One will be completing an addendum to the 2025 Burlington to Nanticoke Regional Infrastructure Plan ("RIP") in parallel with the Hamilton Area Addendum.

The London Area IRRP and the RIP Addendum will consider changes to the 115 kV subsystem in the Woodstock and Brant sub-regions, which form part of the Brant Extended Area. As a result, proposed changes in any of the sub-regions will be coordinated across the Hamilton Area Addendum, RIP Addendum, and London Area IRRP to ensure that recommendations across the three regional planning products are aligned.

The Niagara Bulk Study will commence in 2026 in response to strong economic development in the Niagara transmission zone. Some of the 230 kV system in the Hamilton sub-region is part of the bulk interface towards Niagara, thus any reinforcements to the 230 kV system in either the Hamilton Area Addendum or the Niagara Bulk Study will impact the other. Consequently, proposed changes across the two studies will be coordinated to ensure that recommendations are aligned.

J.4 Activities, Timeline, and Primary Accountability

Table 17 | Addendum Timelines & Activities

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. [*Pre Kick-off*] Engage key municipalities and review relevant community plans, if applicable	LDCs, key municipalities, and IESO	Relevant community plans	Q4 2025-Q1 2026
2. Finalize the planning forecast scenarios and official Addendum kick-off	All		Q1 2026
3. Complete system studies to identify needs - Include bulk system assumptions as identified in Data and Assumptions - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	IESO, Hydro One Transmission	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q2 2026
4. Reconfirm load transfer capabilities for stations in the region	LDCs	Load transfer capabilities under normal and emergency conditions	Q2 2026
5. Needs and Options Screening Webinar	IESO	Community and Stakeholder Engagement Plan Input from local municipalities and Indigenous communities	Q2 2026
a. Early engagement, including with local municipalities, Indigenous communities within study area, First Nation communities with an interest in the study area, and the Métis Nation of Ontario	All	Targeted meetings with municipal representatives and Indigenous communities with an opportunity to collect feedback	

Activity	Lead Responsibility	Deliverable(s)	Timeframe
b. Undertake community and stakeholder engagement webinar	All	Host a public webinar for all interested parties with an opportunity to collect feedback	
c. Summarize input and incorporate feedback	All	Publish the IESOs response to feedback on the dedicated engagement page	
6. Develop options and alternatives - Conduct a screening to identify wires and non-wires options - Develop screened-in wires and non-wires options, and portfolios of integrated alternatives - Conduct technical comparison and evaluation	All	Develop flexible planning options for forecast scenarios	Q2-Q4 2026
7. Options Analysis and Draft Recommendations Webinar	IESO	Community and Stakeholder Engagement Plan Input from local municipalities and Indigenous communities	Q4 2026
a. Early engagement, including with local municipalities, Indigenous communities within study area, First Nation communities with an interest in the study area, and the Métis Nation of Ontario	All	Targeted meetings with municipal representatives and Indigenous communities with an opportunity to collect feedback	
b. Undertake community and stakeholder engagement webinar	All	Host a public webinar for all interested parties with an opportunity to collect feedback	

Activity	Lead Responsibility	Deliverable(s)	Timeframe
c. Summarize input and incorporate feedback	All	Publish the IESOs response to feedback on the dedicated engagement page	
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q1 2027
9. Prepare the Addendum report detailing the recommended near-, medium-, and long-term plan for approval by TWG	IESO	Addendum Report	Q1 2027

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

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

ieso.ca

@IESO_Tweets
linkedin.com/company/IESO

Connecting Today.
Powering Tomorrow.