Ottawa Area Sub-Region Integrated Regional Resource Plan Appendices

July 31, 2025

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Appendix A – Overview of the Regional Planning Process

In Ontario, meeting the electricity needs of customers at a regional level is achieved through regional planning. This comprehensive process starts with an assessment of the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in the development of a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as-needed basis in Ontario for many years. Most recently, planning activities to address regional electricity needs were the responsibility of the former Ontario Power Authority (OPA), now the Independent Electricity System Operator (IESO), which conducted joint regional planning studies with distributors, transmitters, and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the 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 it to lead two out of four phases of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence became the responsibility of the IESO.

The regional planning process begins with a needs assessment process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO conducts a scoping assessment to determine what type of planning is required for a region. A scoping assessment explores the need for a comprehensive IRRP, which considers conservation, generation, transmission, and distribution solutions, or whether a more limited "wires" solution is the preferable option, in which case a transmission- and distribution-focused regional infrastructure plan (RIP) can be undertaken instead. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the scoping assessment, the IESO produces a report that includes the results of the needs assessment process and a preliminary terms of reference. 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 a minimum of every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a 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, electricity Demand Side Management (eDSM), 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:

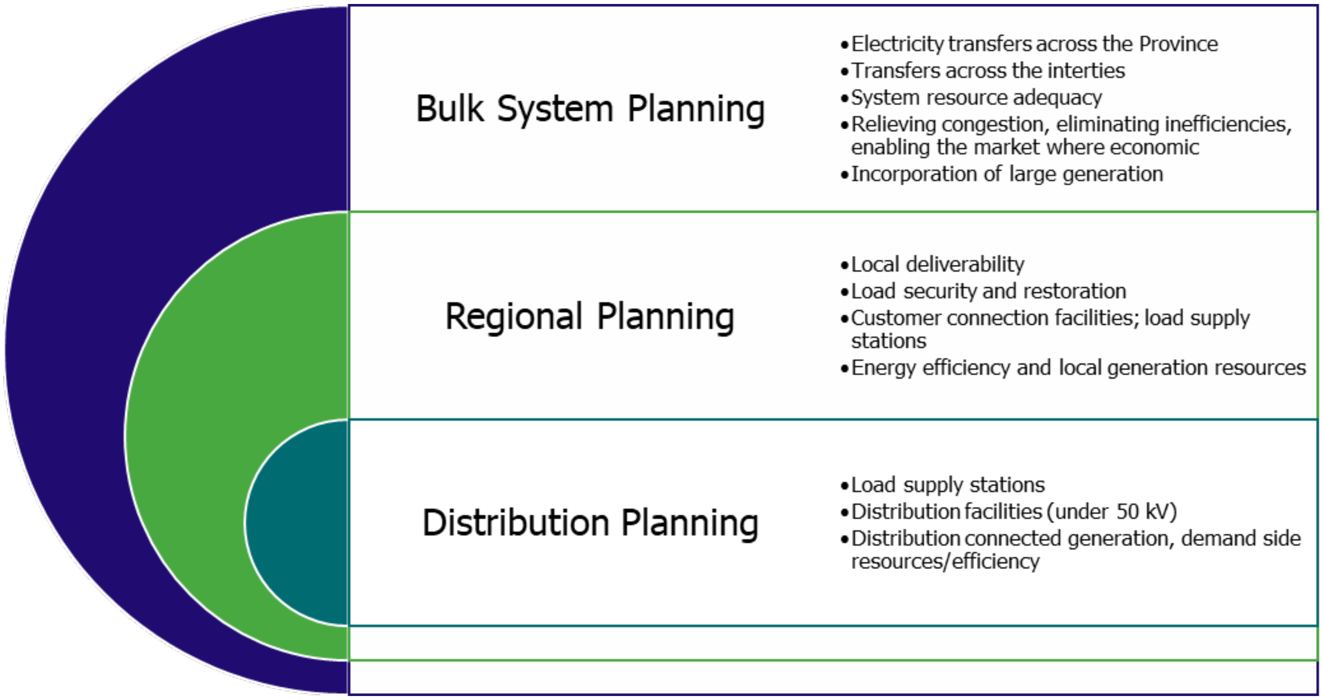
- Bulk system planning
- Regional system planning
- Distribution system planning

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. This type of planning is typically carried out by the IESO pursuant to government policy. Distribution planning, which is carried out by 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.

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 additional eDSM, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

Figure 1 | Levels of Electricity System Planning



Appendix B – Peak Demand Forecast

B.1 Method for Accounting for Weather Impact on Demand

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

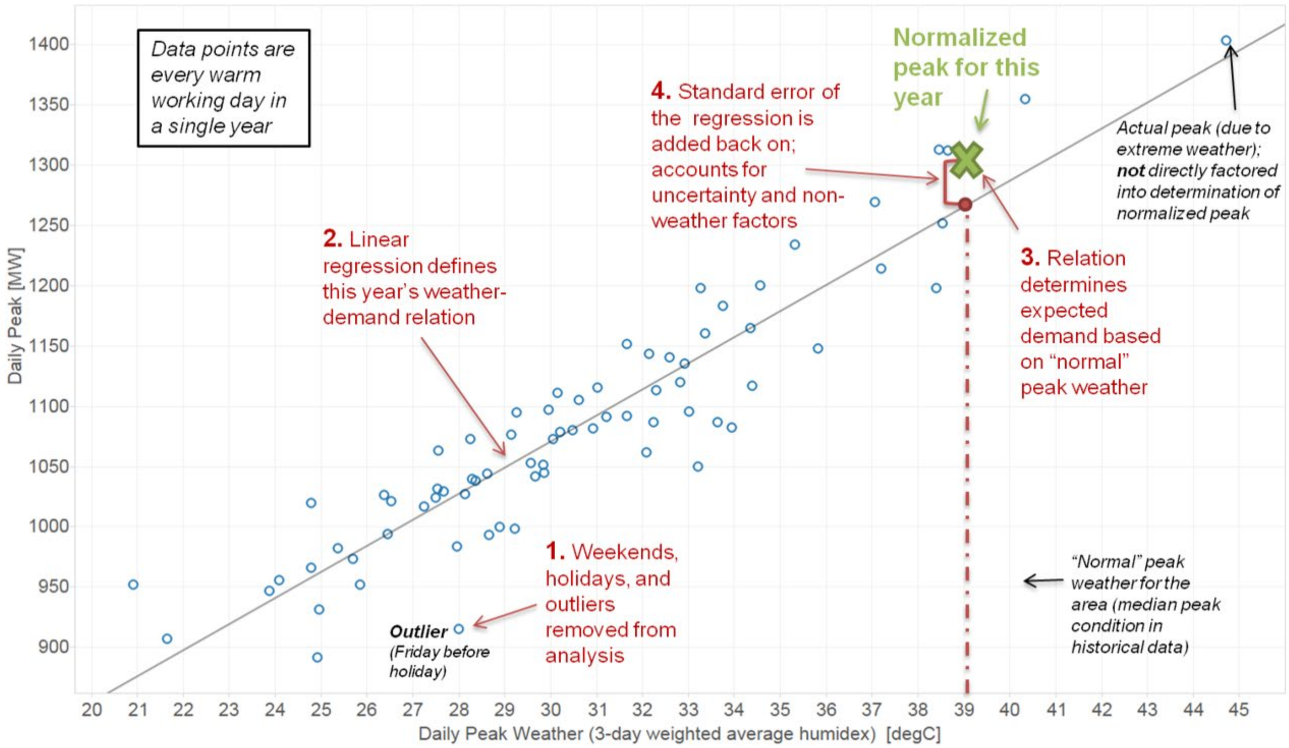
First, the historical loads were adjusted to reflect the median peak weather conditions for each transformer station in the area for the forecast base year (in this case 2022). Median peak refers to what peak demand would be expected if the "normal", or 50th percentile, weather conditions were observed. The 50th percentile is determined from a data set of the hottest day of each year for 30 historical years. This means that in any given year there is an estimated 50% chance of exceeding this peak, and a 50% chance of not meeting this peak. The methodological steps are described in Figure 2.

The 2022 median weather peak on a station and local distribution company (LDC) load basis was provided to each LDC. This data was used as a starting point from which to develop 20-year demand forecasts, using the LDCs forecasting methodology of choice (described in the proceeding sections). The effects of DG were added to the starting points before sending them out to the LDCs, so that a gross forecast may be provided back to the IESO.

Once the 20-year horizon, median peak demand forecasts were returned to the IESO, the normal weather forecast was adjusted to reflect the impact of extreme weather conditions on electricity demand. To find extreme weather, the same process shown in Figure 2 is completed. However, instead of using 50th percentile, the temperature of the hottest day in 30 years of historical data is used. The factors between the median peak and the extreme peak are recorded for the starting point years and averaged. This value is then used to convert the forecast to extreme weather conditions.

Subsequently, the impacts of estimated electricity Demand-Side Management (eDSM) savings and Distributed Generation (DG) output were netted out of the forecast to create the final planning forecast. The studies used to assess the adequacy and reliability of the electric power system generally require studies to be based on extreme weather demand, or, expected demand under the hottest weather conditions that can be reasonably expected to occur. Peaks that occur during extreme weather (e.g. summer heat waves) are generally when the electricity system infrastructure is most stressed.

Figure 2 | Method for Determining the Weather-Normalized Peak



B.2 Hydro Ottawa Forecast Methodology

B.2.1 Methodology

Hydro Ottawa engaged a consultant to develop scenarios for modeling future decarbonization system loads. To forecast and assess the impact of decarbonization initiatives on the service territory and distribution system, the consultant considered known and anticipated policy drivers and trends, as well as existing decarbonization and emissions reduction studies.

The scenarios used the 2022 weather-normalized summer coincident peak at the system level as the baseline. The residential and commercial customer segment baseload was developed by using population growth rates from the Medium Projection scenario in the City of Ottawa's *New Official Plan*, while federal and large customer growth rates were based on decarbonization and sustainability plans.

New electrification loads were developed across the following five categories: transportation electrification, residential electrification, commercial electrification, federal building electrification, and large customer electrification. Each category was projected using a decarbonization curve and additional assumptions about the technology employed to meet specific needs such as space heating or water heating.

Three decarbonization scenarios were investigated:

1. **Policy Guided**: this scenario adheres to policy-driven decarbonization; total compliance to Canadas 2030 Emissions Reduction Plan, Electric Vehicle Availability Standard, and the Canadian Net-Zero Emissions Accountability Act.
2. **Reference**: this scenario incorporates known trends into the policy-driven decarbonization; observed trends in load growth and electrification were paired with short-term planning projections to temper the pace of decarbonization in the near-term while still meeting Canada's 2030 Emissions Reduction Plan and Canada's 2050 decarbonization goals.
3. **Dual Fuel**: This scenario assumes hybrid space heating using low-carbon gas when temperature fall below -10°C.

The electric vehicle, transit and electrified heating targets for each decarbonization scenario are outlined in Table 1 below.

Table 1 | Hydro Ottawa Decarbonization Scenarios

Scenario	Electric Vehicles	Transit	Electrified Heating
Policy Guided	EV adoption meets federal targets	Electric buses meet Ottawa targets	Complete electrification
Reference	EV adoption meets federal targets	Electric buses meet Ottawa targets	Partial electrification with moderate heat pump adoption
	Adoption of rate incentive		Remaining pipeline gas assumed as low-carbon fuels
Dual Fuel	EV adoption meets federal targets	Electric buses meet Ottawa targets	Partial electrification with moderate heat pump adoption
	Adoption of rate incentive		Dual-fuel heating assumptions below -10°C
			Remaining pipeline gas assumed as low-carbon fuels

The IESO considers two scenarios for the IRRP demand forecast: a Base Forecast and a High Electrification Forecast.

Hydro Ottawa's Reference scenario was used for the IRRP's Base Forecast and the Policy Guided Scenario was used for the IRRPs High Electrification Forecast. For sensitivity analysis the Dual Fuel Scenario was also shared with the IRRP working group.

B.2.2 Assumptions

B.2.2.1 EV Assumptions

Hydro Ottawa's EV projections rely on the Government of Canada's (GOC) *Electric Vehicle Availability Standard*. All three scenarios align with the GOC's sales targets for new light-duty vehicles (LDV) of 60% by 2030 and 100% by 2035, with medium-duty vehicles (MDV) and heavy-duty vehicles (HDV) projected as 10% of LDV sales by 2050.

The Reference and Dual Fuel scenario assume 75% of EV drivers adopt the Ontario Government's ultra-low overnight (ULO) rate incentive until 2030 and a new rate incentive optimized to flatten future system-level load curves applied beyond 2030. The Policy Guided scenario does not assume EV load shifting as a result of rate incentives.

B.2.2.2 Electrified Heating Assumptions

Residential electrification included load from space heating and water heating. NRCan data was used to quantify energy consumption by end use and fuel type. Space heating and water heating were electrified based on expected technology share (heat pumps or electric resistance). A blended coefficient of performance was employed to convert the amount of energy used by natural gas to electricity or low carbon fuels such as hydrogen or Renewable Natural Gas.

Historical weather data in Ottawa was used to project electrified heating space heating load curves over the course of a year. For water heating, efficiency metrics were applied to known energy demand from natural gas-fired residential water heating and known load profiles from regions with similar climates to create annual hourly load projections. Blended efficiency metrics for both space heating and water heating were reduced in all scenarios for hours at or below -10°C based on historical weather data. This was to account for the assumed diminished efficiency of air-source heat pump technology in temperatures experienced in Ottawa's climate.

Electrification for commercial, federal and large customers included potential electrification load from space heating, water heating, space cooling, and auxiliary equipment. Space heating, space cooling, and water heating were electrified based on fuel share (electric vs low carbon gas). A blended coefficient of performance was employed to convert the amount of energy used by natural gas to electricity. Like the residential sector, blended efficiency metrics for both space heating and water heating were reduced in all scenarios for hours at or below -10°C based on historical weather data.

B.2.2.3 Transit Assumptions

Electric bus projections were based on the Zero Emissions by 2040 forecast in the City of Ottawa's Energy Evolution Strategy, which projects full electrification of the bus fleet by 2040.

B.2.3 References

The following plans were referenced to define the scenarios described in Section B.2:

- 2030 Emissions Reduction Plan – Canada's Next Steps for Clean Air and a Strong Economy, Environment and Climate Change Canada
- Canada's Action Plan for Clean On-Road Transportation, Government of Canada

- Climate Change Master Plan, City of Ottawa
- Community Energy Transition Strategy, City of Ottawa
- Electric Vehicle Availability Standard, Government of Canada
- Energy Evolution, City of Ottawa
- Green Energy Act, City of Ottawa
- Net Zero 2050, Ontario Energy Association
- Official Plans & Community Energy Plans, City of Ottawa
- Pathway Study on Transportation in Ottawa, Sustainability Solutions Group
- Pathways to Decarbonization, IESO
- Pathways to Net-Zero Emissions for Ontario, Enbridge
- Zero Emissions Bus Program, OC Transpo

B.3 Hydro One Forecast Methodology

B.3.1 Methodology

Hydro One employed both econometric and end-use approaches to develop forecasts for the Ottawa Area Sub-region IRRP. These forecasts were derived by leveraging provincial load forecasts, which were adjusted for stations in Ottawa based on their historical relationship. Additionally, local information, including Municipal Energy Plans, Official Plans and local and regional demographic and economic factors, was incorporated to the forecast and ensure its alignment with local and regional conditions.

B.3.2 Assumptions

B.3.2.1 GDP and Housing Assumptions

Hydro One used different Ontario's GDP annual growth rates and Ontario housing growths for Reference Case and High Electrification Forecast which are outlined in Table 2 below.

Table 2 | Ontario GDP Annual Growth Rate and Housing

Scenario		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base Forecast	Ontario GDP Annual Growth Rates (%)	0.3	1.8	2.4	2.6	2.4	2.0	2.0	1.7	1.8	1.8
	Ontario Housing (thousands)	85,879	81,110	55,603	55,430	55,436	55,533	56,922	60,424	62,191	62,857

High Electrification Forecast	Ontario GDP Annual Growth Rates (%)	0.5	2.0	2.6	2.8	2.6	2.5	2.5	2.2	2.3	2.3
	Ontario Housing (thousands)	88,879	84,110	83,603	70,430	70,436	70,533	71,922	75,424	77,191	77,857

Scenario		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Base Forecast	Ontario GDP Annual Growth Rates (%)	1.8	1.6	1.8	1.7	1.7	1.8	1.7	1.7	1.6	1.6
	Ontario Housing (thousands)	63,524	64,191	64,857	65,524	66,191	66,857	67,524	68,191	68,857	69,524
High Electrification Forecast	Ontario GDP Annual Growth Rates (%)	2.3	2.1	2.3	2.2	2.2	2.3	2.2	2.2	2.1	2.1
	Ontario Housing (thousands)	78,524	79,191	79,857	80,524	81,191	81,857	82,524	83,191	83,857	84,524

B.3.2.2 EV, Heat Pump, and Electrification of Transit Assumptions

EVs and electrification assumptions are based on latest government mandates and initiatives in this regard. Hydro One has an aggregate forecast of electrification, which includes heat pumps, alternative use of electricity for heating load and the transit system.

The aggregate forecast helps to have a consistent forecast for a variety of heating options. For example, if natural gas combined with hydrogen is used in place of a heat pump, then electricity used for making the hydrogen is counted for in the aggregate in place of electricity usage of heat pumps.

B.3.2.3 Other Drivers of Load Growth

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, were also considered.

A review of the community energy plans indicated that they are consistent with Canada's decarbonization policy. In addition to the Ottawa plan that relates to all communities/suburbs of Ottawa and corresponding stations, the community energy plans reviewed included those for Cumberland County that relates to Cumberland DS and Bilberry Creek TS; Greely Community for Greely DS, and Township of Russell for Russell DS.

B.3.3 References

The following plans were referenced to define the forecasts, as described in Section 2.2.3:

- Energy Evolution, City of Ottawa

- Cumberland Energy Authority Energy Plans
- Greely Community Design Plan
- Township of Russell Strategic Plan

B.4 Electricity Demand Side Management (eDSM) Assumptions

Electricity demand side management (eDSM) measures can reduce the electricity demand, and their impact can be separated into the two main categories: Building Codes & Equipment Standards, and eDSM programs. The assumptions used for the Ottawa IRRP forecast are consistent with the eDSM 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 forecasted residential, commercial, and industrial gross demands. A top-down approach was used to estimate peak demand savings from the provincial level to the Ottawa transmission zone and then allocated to the study region. This section describes the process and methodology used to estimate eDSM savings for the Ottawa sub-region of the study and provides more details on how the savings for the two categories were developed.

B.4.1 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 study region, the associated peak demand savings for codes and standards by sector were estimated for the Ottawa zone and compared with the gross peak demand forecast for the zone. From this comparison, annual peak reduction ratios were developed for the purpose of allocating the associated savings to each station in the region. The analyses were done for summer and winter separately and seasonal peak reduction ratios were estimated.

First, summer peak demand savings were estimated from summer gross demand forecast. New peak demand savings from codes and standards were estimated from 2024 to 2043. The residential summer peak reduction ratios of each year were applied to the forecasted residential summer peak demand at each station to develop an estimate of summer peak demand impacts from codes and standards. By 2043, the residential sector in the region is expected to see about 7.6% summer peak demand savings through codes and standards. The same is done for the commercial sector, which will see about 3.7% summer peak demand savings through codes and standards by 2043. No codes and standards saving was assumed for the industrial sector. The sum of the savings associated with the two sectors is the total summer peak demand impact from codes and standards.

The process was repeated for winter peak demand forecasts. By 2043, the residential sector and commercial sector in the region are expected to see about 6.3% and 2% respectively winter peak reductions through codes and standards.

B.4.2 Estimated Savings from Demand Side Management Programs

In addition to codes and standards, the delivery of eDSM programs reduces electricity demand. The impact of existing and planned eDSM programs were analyzed, which include the 2021-2024

Conservation and Demand Management Framework, the existing federal programs, and the assumed continuation of provincial programs beyond 2024 at savings levels consistent with the 2021-2024 framework (the current framework at time of demand forecast development) 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 Ottawa transmission zone, and finally to the stations in the study Ottawa sub-region. Persistence of the peak demand savings from eDSM programs were considered over the forecast period.

Similar to the estimation of peak demand savings from codes and standards, summer and winter peak demand reduction ratios from program savings were developed by sector. The sectoral peak reduction ratios were derived by comparing the forecasted peak demand savings with the corresponding gross forecasts in the Ottawa transmission zone. They were then applied to the sectoral gross peak forecast of each station in the study region. By 2043, the residential sector in the region is expected to see about 0.4% summer peak demand savings through programs, while commercial sector and industrial sector will see about 3.9% and 15.5% summer peak reduction respectively. Winter peak reductions by 2043 were estimated as 0.5%, 2.9%, and 14.3% from residential, commercial and industrial programs.

B.4.3 Total eDSM 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.

See Table 1 and Table 2 in the Ottawa Area Sub-Region IRRP Appendix Excel file for the eDSM Forecasts for winter and summer.

B.5 Installed Distributed Generation and Contribution Factor Assumptions

See Table 3 and Table 4 in the Ottawa Area Sub-Region IRRP Appendix Excel file for the Distributed Generation Contribution Factor Assumptions in winter and summer.

See Table 5 and Table 6 in the Ottawa Area Sub-Region IRRP Appendix Excel file for the Installed Distribution Generation Output Assumptions in winter and summer.

B.6 Final Peak Forecast by Station

After taking the median weather forecast provided by the LDCs and applying eDSM and DG assumptions above, forecasts were adjusted to extreme weather. The final peak demand forecasts, by station, are provided in Table 7 and Table 8 in the Ottawa Area Sub-Region IRRP Appendix Excel file in winter and summer.

B.7 High Forecast Scenario

See Table 9 and Table 10 in the Ottawa Area Sub-Region IRRP Appendix Excel file for the High Forecast Scenarios in winter and summer.

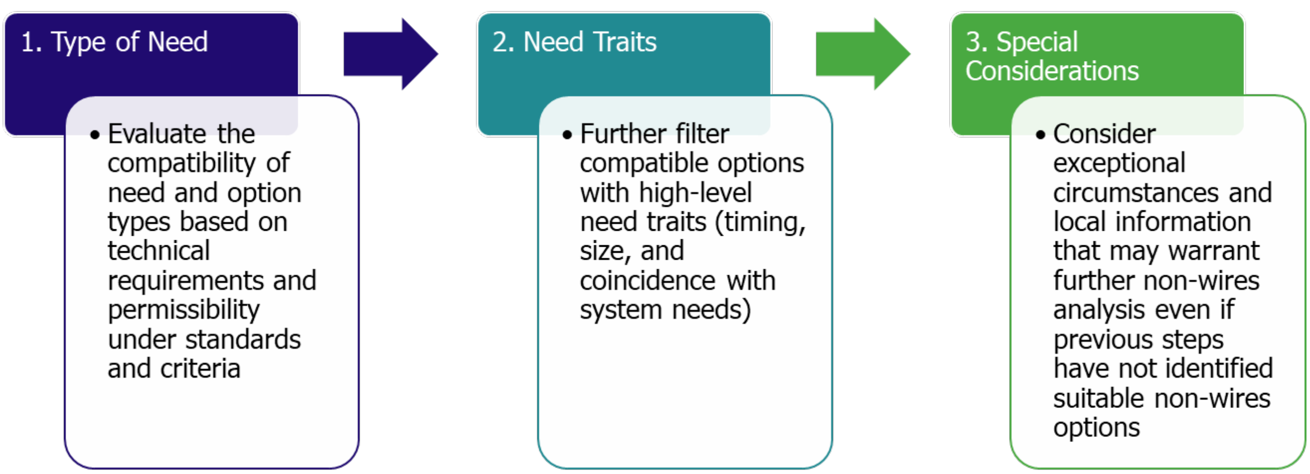
Appendix C – IRRP Screening Mechanism

The IESO developed a guide to the current general approach for evaluating non-wires alternatives (NWAs) 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, eDSM, distributed generation, and demand response. Table 3 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 4.

Table 3 | 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
eDSM	Yes	Yes	Yes	No	No
Distributed generation	Yes	Yes	Yes	No	Yes
Demand response	Yes	Yes	Yes	No	No

Table 4 | 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
eDSM	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 Ottawa Area Sub-Region IRRP, hourly load forecasting was completed on a subsystem basis, focusing on groups of stations where there was a 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 the Kanata-Stittsville and Core East subsystems (Pocket 1 and Pocket 2) as shown in the IRRP. Kanata-Stittsville consists of 230 kV stations Nepean TS, Kanata MTS, and South March TS. Core East Pocket 1 consists of the 115 kV stations Nepean Epworth MTS, Carling TS, and Lisgar TS. Core East Pocket 2 is all other 115 kV stations in the Core East downtown region. These three regions were identified as candidates for non wires through initial screening.

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.

First, a density-based clustering algorithm is used for filtering the historical data for outliers (including fluctuations possibly caused 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, 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 4 | Summary of the Hourly Forecasting Methodology for IRRPs

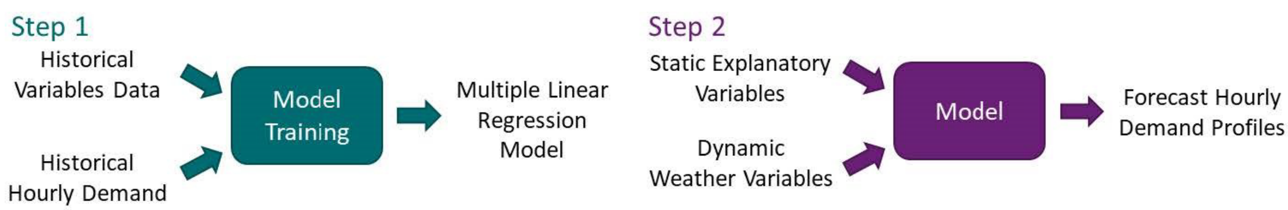
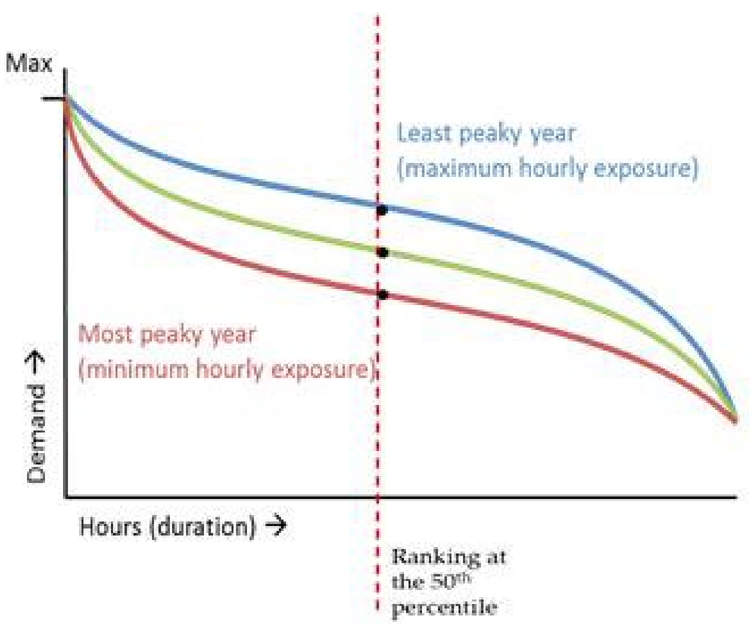


Figure 5 | Illustrative Example: Ranking Hourly Load Profiles by Energy



For this IRRP, LDC hourly load profiles were also an input into the IRRP hourly load forecasts. In the case where an LDC had their own internal set of hourly load profiles that accounted for electrification for a group of stations, those profiles were extended and interpolated so that they covered the entire forecast horizon and then scaled to the forecast peak. The total annual energy of the LDC forecasts was compared to the total annual energy from the traditional linear regression model outputs to ensure that they were similar.

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.

D.2 Subsystem Capacity Need

Figure 6 through Figure 11 show monthly and hourly heat maps produced for Kanata-Stittsville, and Core East Pocket 1 and Pocket 2 to illustrate some of the capacity need characteristics in 2030 (mid-term). 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.

D.2.1 Kanata-Stittsville Subsystem Capacity Need

To read the heat maps, it is estimated that loading in the Kanata-Stittsville Subsystem area exceeds the LMC by 13 MW for roughly 40% of total hours in January 2030, as indicated in the Figure 6. Load levels are estimated to infrequently exceed the LMC by 13 MW mostly in the winter season (December to March). From an hourly perspective, high magnitude needs greater than 80 MW will likely occur during the evening hours, 6 PM – 11 PM, as shown in Figure 7. However, there is a significant need across all hours of the day.

Figure 6 | Monthly Heat Map of Kanata-Stittsville Need Magnitudes in 2030

MW Range		Month											
		1	2	3	4	5	6	7	8	9	10	11	12
	120	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	106.6667	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	93.33333	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	80	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	66.66667	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	53.33333	12%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	40	16%	6%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	26.66667	24%	10%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%
	13.33333	40%	16%	1%	0%	0%	0%	0%	0%	0%	0%	0%	5%
	0	57%	28%	2%	0%	0%	0%	0%	0%	0%	0%	0%	12%

Figure 7 | Hourly Heat Map of Kanata-Stittsville Need Magnitudes in 2030

MW Range		Hour																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	120	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	106.667	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	93.3333	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	80	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	66.6667	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%
	53.3333	0%	0%	0%	0%	0%	0%	0%	2%	2%	3%	2%	1%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%
	40	0%	0%	0%	0%	0%	0%	0%	3%	4%	4%	3%	2%	1%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	0%
	26.6667	1%	0%	0%	0%	0%	0%	2%	4%	5%	5%	4%	2%	1%	0%	0%	0%	0%	1%	3%	2%	1%	2%	2%	0%
	13.3333	2%	1%	1%	1%	1%	2%	4%	7%	7%	6%	4%	2%	1%	1%	0%	0%	0%	4%	5%	4%	2%	2%	3%	0%
	0	3%	2%	2%	2%	2%	4%	6%	7%	7%	7%	5%	3%	3%	3%	3%	2%	3%	7%	9%	6%	5%	4%	3%	0%

D.2.2 Core East Subsystem Pocket 1 Capacity Need

For the Core East Subsystem Pocket 1 area, it is estimated that its loading exceeds the LMC by 15 MW for roughly 37% of total hours in January 2030, as indicated in Figure 8. Similar to Kanata-Stittsville area, this area exceeds the LMC in winter months of: December, January, February, and March. From an hourly perspective, high magnitude needs greater than approximately 50 MW will likely occur during the morning hours, 9 AM – 12 PM, as shown in Figure 9. However, there is a significant need across all hours of the day.

Figure 8 | Monthly Heat Map of Core East Pocket 1 Need Magnitudes in 2030

MW Range		Month 1	2	3	4	5	6	7	8	9	10	11	12
	70	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	62.22222	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	54.44444	6%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	46.66667	9%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	38.88889	13%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	31.11111	15%	6%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	23.33333	21%	8%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%
	15.55556	37%	12%	1%	0%	0%	0%	0%	0%	0%	0%	0%	2%
	7.777778	49%	17%	2%	0%	0%	0%	0%	0%	0%	0%	0%	3%
	0	63%	29%	4%	0%	0%	0%	0%	0%	0%	0%	0%	4%

Figure 9 | Hourly Heat Map of Core East Pocket 1 Need Magnitudes in 2030

MW Range		Hour 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	70	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	62.2222	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	54.4444	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	46.6667	0%	0%	0%	0%	0%	0%	0%	1%	2%	2%	2%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	38.8889	0%	0%	0%	0%	0%	0%	0%	2%	3%	3%	2%	1%	1%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%
	31.1111	0%	0%	0%	0%	0%	0%	1%	3%	4%	4%	3%	1%	1%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%
	23.3333	0%	0%	0%	0%	0%	0%	2%	4%	5%	5%	3%	2%	1%	1%	0%	0%	0%	1%	1%	1%	1%	1%	1%	0%
	15.5556	1%	1%	1%	1%	1%	1%	3%	6%	6%	5%	4%	3%	2%	2%	1%	1%	1%	2%	2%	1%	1%	2%	2%	0%
	7.77778	2%	2%	1%	1%	2%	3%	5%	6%	7%	6%	5%	3%	3%	3%	2%	2%	2%	3%	4%	2%	1%	2%	2%	0%
	0	3%	3%	3%	3%	3%	4%	6%	7%	7%	7%	6%	5%	5%	4%	4%	3%	4%	5%	5%	4%	2%	2%	2%	0%

D.2.3 Core East Subsystem Pocket 2 Capacity Need

For Core East Subsystem Pocket 2 area, it is estimated that its loading exceeds the LMC by 22 MW for roughly 51% of total hours in January, as indicated in Figure 10. Similar to two previous areas, this area exceeds the LMC in winter months of: December, January, February, and March. From an hourly perspective, the high magnitude needs greater than approximately 70 MW will likely occur during the morning hours, 9 AM – 12 PM, as shown in Figure 11. However, there is a significant need across all hours of the day.

Figure 10 | Monthly Heat Map of Core East Pocket 2 Need Magnitudes in 2030

MW Range	100	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	88.88889	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	77.77778	6%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	66.66667	16%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	55.55556	26%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	44.44444	33%	6%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	33.33333	41%	12%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	22.22222	51%	15%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	11.11111	56%	23%	2%	0%	0%	0%	0%	0%	0%	0%	0%	1%
	0	68%	27%	2%	0%	0%	0%	0%	0%	0%	0%	0%	2%
		1	2	3	4	5	6	7	8	9	10	11	12
		Month											

Figure 11 | Hourly Heat Map of Core East Pocket 2 Need Magnitudes in 2030

MW Range	100	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	88.8889	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	77.7778	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	66.6667	0%	0%	0%	0%	0%	0%	0%	0%	5%	5%	3%	1%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%
	55.5556	0%	0%	0%	0%	0%	0%	0%	1%	7%	6%	6%	3%	1%	1%	0%	0%	0%	1%	2%	1%	1%	1%	0%	0%
	44.4444	0%	0%	0%	0%	0%	0%	0%	2%	7%	8%	8%	4%	2%	1%	1%	1%	1%	1%	2%	1%	1%	1%	0%	0%
	33.3333	0%	0%	0%	0%	0%	0%	0%	5%	11%	12%	8%	5%	2%	2%	1%	1%	1%	1%	2%	2%	1%	1%	1%	0%
	22.2222	0%	0%	0%	0%	0%	0%	0%	8%	13%	14%	10%	5%	2%	2%	1%	1%	1%	1%	2%	2%	1%	1%	2%	0%
	11.1111	0%	0%	0%	0%	0%	0%	2%	11%	16%	15%	12%	6%	2%	2%	1%	1%	1%	1%	2%	2%	2%	1%	2%	0%
	0	1%	1%	1%	0%	0%	1%	5%	13%	19%	18%	13%	6%	2%	2%	1%	1%	1%	1%	2%	4%	2%	3%	3%	0%
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
		Hour																							

Appendix E – Electricity Demand Side Management

E.1 Achievable Potential Studies

Electricity Demand-Side Management (eDSM) is a low-cost resource that offers significant benefits to individuals, businesses, and the electricity system as a whole. Targeting additional eDSM 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 eDSM in a local area, data and assumptions can be leveraged from provincial eDSM 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 potential (for both electricity and natural gas), 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 EDSM 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 eDSM 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, eDSM 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 forecasted savings that are expected to come from existing provincial and federal eDSM programs, the forecasted savings that are expected to come from future anticipated eDSM programs, as well as savings from codes and standards, were netted out and the remaining achievable savings potential were identified. The remaining potential provides an estimate of the amount of incremental eDSM savings potential that could help address emerging local needs in the Ottawa Area Sub-Region.

E.2 Local Achievable Potential Study

To further enhance and supplement the standard consideration of eDSM in regional planning work underway for Ottawa, the IESO is conducting a Local Achievable Potential Study (LAPS) to identify potential for behind-the-meter distributed energy resources (DERs), demand response, and energy efficiency programs. The study will identify and quantify electricity energy savings potential, peak demand savings potential and associated costs attainable through energy efficiency, demand response, and behind-the-meter DERs over a 20-year period of 2025 to 2045. Study results are expected to be published in Q3 2025. The IESO is working in collaboration with Hydro Ottawa to help leverage the local insights and relationships.

The APS will use two local load forecasts that are aligned with the Ottawa IRRP's reference and high forecast scenarios. For each scenario, the study will use a bottom-up approach to determine the energy savings potential from a technical, economic and achievable perspective:

- Technical Potential is the savings resulting from the implementation of all technically feasible measures.
- Economic Potential is the savings resulting from the implementation of all technically feasible measures that pass the cost-effectiveness test (PAC).
- Achievable Potential is the savings that can cost-effectively and realistically be acquired once considered adoption dynamics and real-world barriers.

These savings are simulated at the building level (using a digital twin of residential and commercial and institutional building stock) and aggregated to the station level for each scenario. Measures in scope include:

- Behind the Meter DER including battery storage, solar and thermal storage
- Energy Efficiency measures including heat pumps, HVAC, lighting, appliances, weatherization, and hot water
- Demand Response including EV charging, HVAC equipment, and water heaters

The final APS will include a presentation of technical, economic and achievable savings, and the associated costs over the 20-year period for both the reference and high electrification forecasts at the station level. A detailed description of the methods, data sources, input assumptions, and data tables will be published. For more information on the scenarios, methodology and data inputs please refer to the study's technical approach document.

E.3 Incremental Energy Savings Forecasts for the Ottawa Area Sub-Region

Figure 12 to Figure 14 are obtained by applying the zonal rates of savings potential from the last provincial APS to the demand forecasts to determine the achievable eDSM savings for the stations in the Ottawa Area Sub-Region. Through the screening process (refer to Table 4), only following subsystems were applicable for eDSM savings: summer eDSM savings for Kanata-Stittsville Subsystem and Core East Subsystem pocket 1 and winter eDSM savings for Core East Subsystem pocket 2.

At the Kanata-Stittsville Subsystem, shown in Figure 12, about 57 MW of incremental eDSM savings potential is estimated to be achievable in 2042. The estimated cost to deliver these savings is $136 million dollars over the forecast period based on APS cost assumptions.

At the Core East Subsystem pocket 1, shown in Figure 13, approximately 47 MW of incremental eDSM savings potential is estimated to be achievable in 2042. The estimated cost to deliver these savings is $129 million dollars over the forecast period.

At the Core East Subsystem pocket 2, shown in Figure 14, approximately 193 MW of incremental e DSM savings potential is estimated to be achievable in 2042. The estimated cost to deliver these savings is $613 million dollars over the forecast period.

Figure 12 | Incremental eDSM Potential at Kanata-Stittsville Subsystem

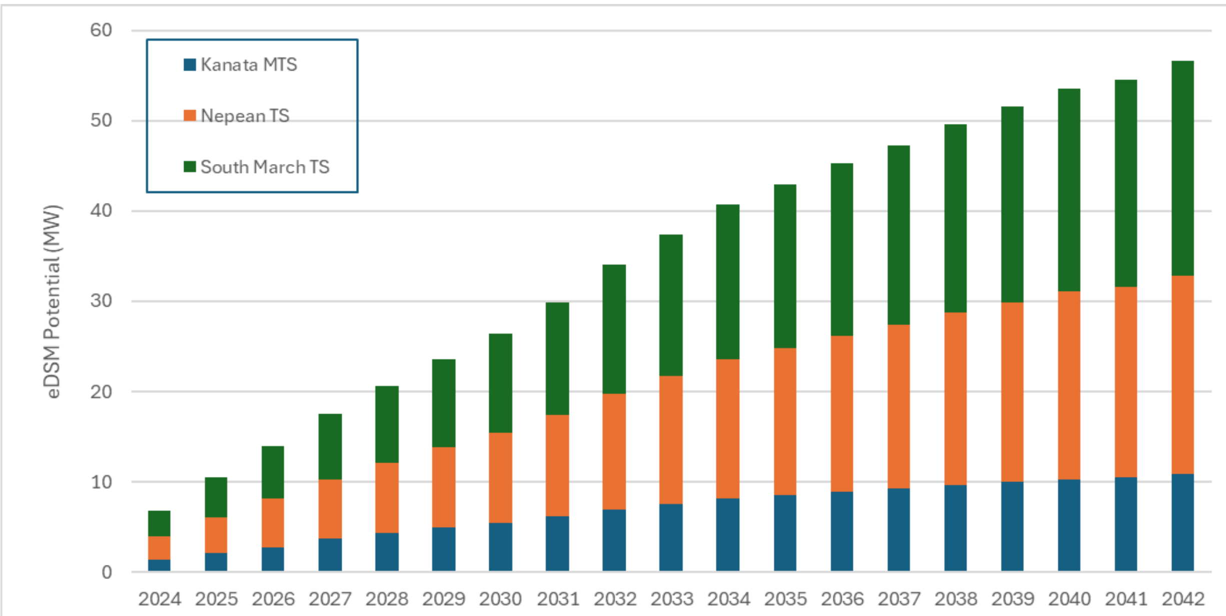


Figure 13 | Incremental eDSM Potential at Core East Subsystem Pocket 1

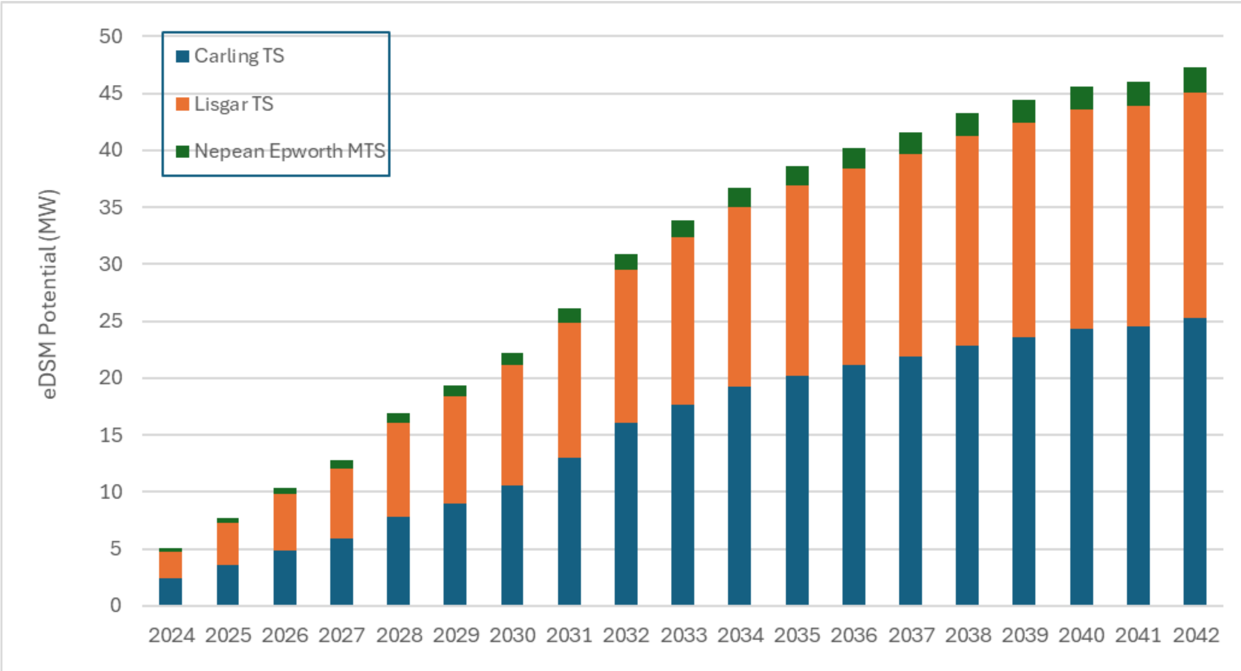
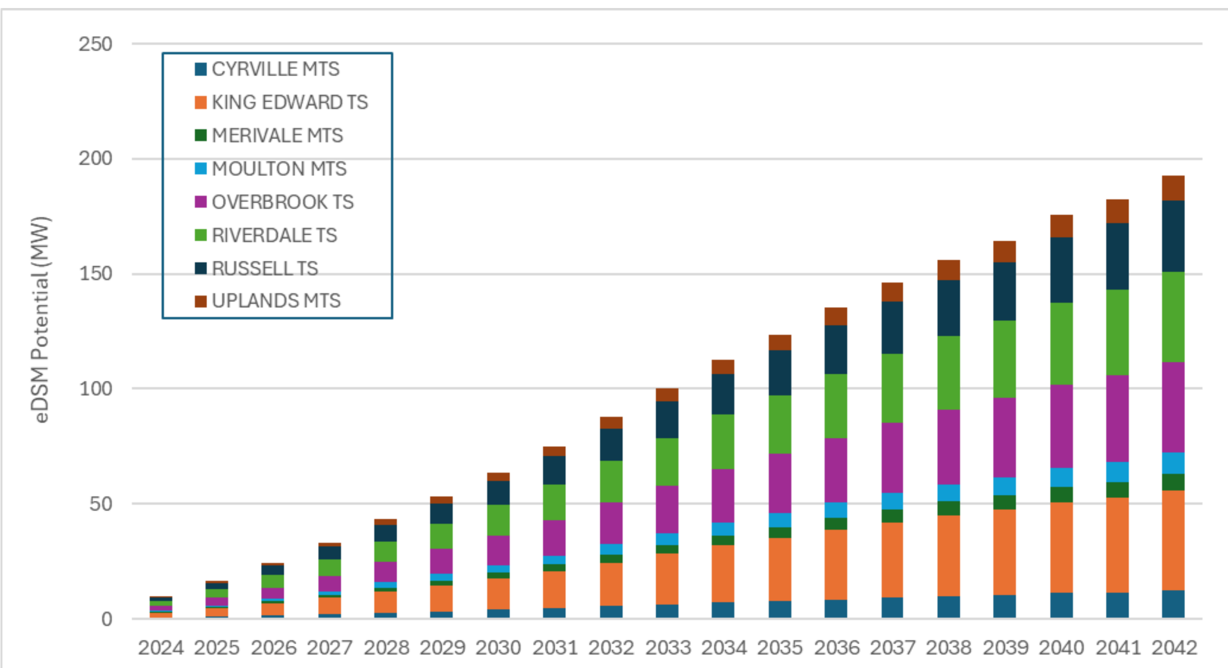


Figure 14 | Incremental eDSM Potential at Core East Subsystem Pocket 2



Appendix F – Economic Assumptions

The following subsections provide a list of the assumptions made in the economic analysis for options addressing needs.

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 0.75 for the study period.
- The NPV analysis was conducted using a 4% real social discount rate. An annual inflation rate of 2% is assumed. Note that only NWA solutions are presented in terms of NPV and Transmission solutions are presented in terms of capital cost estimates.
- The NPV study period for the options analysis started the year that the option could feasibly come into service, and goes to the end of 2101, the point at which 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.
- The life of station assets were assumed to be 45 years; the life of transmission line assets were assumed to be 70 years.

F.3 Resource Assumptions

- Overnight capital costs and operating costs for wind, solar and BESS are based on the 2024 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) Workbook publication, and accounts for the impact of the Clean Investment Tax Credit.
- Plexos capacity expansion model is used to develop the non-emitting resources required to meet the identified hourly needs. Plexos production cost model of 99.5% of load served, confirmed by

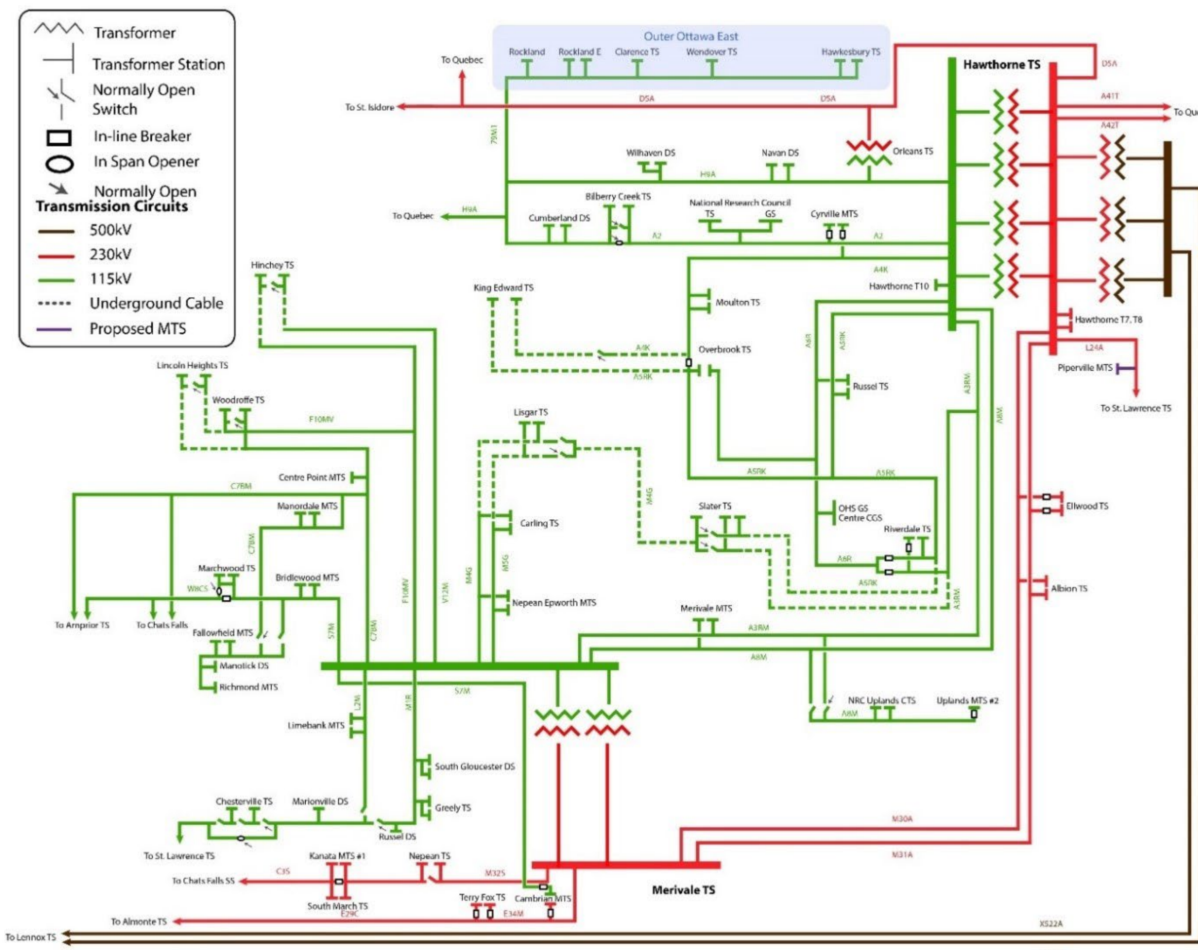
Plexos production cost model, was considered necessary in the peak need year for the NWA to be considered a feasible option.

Appendix G – Planning Study Report

G.1 Introduction

This Planning Study Report documents the results of the power system studies used to determine the planned performance of the electricity system for the Ottawa Area Sub-Region. The results of this planning study were used to inform the development of planning recommendations in the 2025 Ottawa IRRP.

Figure 15 | Single Line Diagram of Ottawa Area Sub-Region



G.2 Planning Performance Criteria

The study adheres to the planning criteria in accordance with events and performance as detailed by:

- North American Electric Reliability Corporation (NERC) TPL-001 “Transmission System Planning Performance Requirements”;
- Northeast Power Coordinating Council (NPCC) Regional Reliability Reference Directory #1 “Design and Operation of the Bulk Power System”; and

- IESO ORTAC.

Table 5 below shows the types of contingencies assessed and how they map to applicable standards. The table also specifies the thermal loading criteria and amount of load rejection/curtailment permitted by ORTAC.

Table 5 | Mapping of Planning Scenarios to NERC / NPCC Standards and ORTAC Criteria

Pre-Contingency	Contingency[1]	Type	Mapping to TPL/D1 Event	Rating[2]	Maximum Allowable Load Loss
All elements in-service	None	N-0	P0	Continuous	None
	Single	N-1	P1, P2	LTE	150 MW by-configuration
	Double	N-2	P7, P4, P5	STE, reduced to LTE	150 MW lost by curtailment / rejection; 600 MW total
Transmission element out-of-service, followed by system adjustments	Single	N-1-1	P6	STE, reduced to LTE	150 MW lost by curtailment / rejection; 600 MW total
	Double	N-1-2	Cat II	STE, reduced to LTE	N/A

In addition to thermal criteria pre- and post-contingency minimum and maximum voltages and voltage change criteria must be adhered to for all scenarios as per **Table 6**.

Table 6 | Mapping of Planning Scenarios to NERC / NPCC Standards and ORTAC Criteria

Applicable Limit	Nominal Bus Voltage (kV)		
	500	230	115
Post-contingency Maximum Voltage	550	250	127
Post-contingency Minimum Voltage	470	207	108

[1] 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.

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

Applicable Limit	Nominal Bus Voltage (kV)		
	500	230	115
Post-contingency Maximum deviation	10%	10%	10%

The system must be shown to be stable if the most critical parameter is increased by 10%, for the following conditions:

- a pre-contingency power transfer (point a) that is 10% lower than the voltage instability point of the pre-contingency P-V curve, and
- a pre-contingency transfer that results in a post-contingency power flow (point b) that is 5% lower than the voltage instability point of the post-contingency curve
- 10% margin on transient instability

Once load is lost either by configuration or by actions such as planned load rejection via a RAS or manual load rejection following a contingency to reduce loading to the LTE ratings, load must be restored in accordance with the following:

- Any load lost must be restored in under 8 hours.
- Any amount of load lost in excess of 150 MW must be restored in 4 hours.
- Any amount of load lost in excess of 250 MW must be restored in 30 minutes.

Load Supply Capacity

Load Supply Capacity assess the need for additional step-down transformer station capacity; the demand outlook was compared to the 10-day limited time rating (LTR) on a station-by-station basis. To account for the possible loss of the companion step-down transformer, the LTR of each transformer station is defined by the most restrictive step-down transformer 10-day LTR rating. No station-to-station or intra-station (bus-to-bus) load transfers were assumed in this assessment. Station load is equal to the sum of all bus loads supplied by the station. For the purposes of station capacity assessments, if low-voltage capacitor banks are installed at the particular station, a load power factor corrected to 0.95 lagging is assumed. If no low-voltage capacity banks are installed, a load power factor of 0.9 lagging is assumed.

Load Security

In accordance with Section 7.1 of ORTAC, following the loss of any element as a result of credible design contingencies, thermal loading must be reduced to within LTE ratings in the time afforded by STE ratings and the total amount of load allowed to be interrupted by configuration, load rejection, and/or curtailment must not exceed 150 MW. In addition to the post-contingency thermal loading, which is forecast to exceed STE, the following post contingency thermal loading is forecast to exceed LTE. Loadings under the 2037 forecast year are reported.

Load Restoration

In accordance with Section 7.2 of ORTAC, following design criteria contingencies on the transmission system, all affected loads must be restored within eight hours, with loads in excess of 150 MW within four hours, and loads in excess of 250 MW within 30 minutes. Loadings under the 2043 forecast year are reported, with the collaboration of the Working Group.

G.3 Demand Assumptions (Study Area)

The planning study used the IRRP planning forecast shown in Appendix B. In 2021, a study was carried out to determine historical power factors for loads of interest and to assess power factor assumptions used in transmission planning studies. The results from the study are used in the Planning Study. Due to the lack of generation in Ottawa, the area is prone to voltage decline problems during outage and contingency scenarios. For this reason, utilizing a power factor of 0.9 (ORTAC minimum requirement) is not preferable.

G.4 Supply Assumptions

According to the ORTAC, a planning study shall assume a level of output for run-of-river hydroelectric generation that is available 98% of the time. This results in an output level of approximately 100 MW for these generators.

G.5 Transmission Assumptions

In addition to existing transmission facilities, transmission facilities that are currently being implemented, or under development or construction, are assumed to be in-service by their estimated completion date. These facilities are summarized in **Table 7.**

Table 7 | New Facilities Assumed in Assessment

Facility	Description	Assumed In-Service Date
Piperville MTS	The proposed Piperville MTS will connect onto 230 kV circuit L24A.	2026
Orleans Area Reconfiguration	The Orleans Area Reconfiguration involves: 1) New 230 kV circuit from Hawthorne TS to Orleans JCT 2) Decommissioning of Bilberry Creek TS 3) New supply station in the Orleans area supplied from D5A and the new 230 kV circuit 4) Upgrade Orleans TS replacing the existing 115 kV supply from H9A to a 230 kV supply from the new 230 kV circuit 5) Existing 115kV transmission circuits in the area will be maintained	2029

Facility	Description	Assumed In-Service Date
Merivale TS: T22 Auto-transformer replacement (2025)	The nearing EOL 230-115 kV auto-transformer is being replaced like-for-like, however the current standard will result in a higher LTR comparable with the existing T21.	2025
Hawthorne TS: T3 Auto-Transformer Replacement	Auto-transformer T3 at Hawthorne TS is scheduled for replacement due to failure.	2024

G.6 Study Results

Load Supply Capacity

The following table (**Table 8**) shows the capacity shortfall between the planning forecast and the station limited time rating (LTR) for the Ottawa Area Sub-Region stations where the planning forecast exceeds the LTR at some point in the forecast period.

Table 8 | Summary of Station Capacity Needs in the Ottawa Area Sub-Region

Time Horizon	Station	Subsystem	Emerging Year Summer	Emerging Year Winter	2043 Need Summer (MW)	2043 Need Winter (MW)
Near Term	Carling TS	Core East – Pocket 1	2028	2029	40	130
	Lisgar TS	Core East – Pocket 1	2025	2027	30	120
	Nepean Epworth MTS	Core East – Pocket 1	2031	2028	1	10
	Cyrville MTS	Core East – Pocket 2	-	2029	0	40
	King Edward TS	Core East – Pocket 2	2037	2026	10	160
	Moulton MTS	Core East – Pocket 2	2028	2028	3	30
	Riverdale TS	Core East – Pocket 2	2038	2028	8	110
	Ellwood MTS	Core East – Pocket 2	2024	2027	60	5
	Bridlewood MTS	Core West – Pocket 1	2032	2029	1	20
	Fallowfield MTS	Core West – Pocket 1	2024	2030	7	40

Time Horizon	Station	Subsystem	Emerging Year Summer	Emerging Year Winter	2043 Need Summer (MW)	2043 Need Winter (MW)
	Marchwood MTS	Core West – Pocket 1	2025	2024	8	40
	Centrepoint MTS	Core West – Pocket 2	2024	2026	2	20
	Manordale MTS	Core West – Pocket 2	2024	2025	3	20
	Greely DS	Core South	2024	2024	10	10
	Limebank MTS	Core South	-	2030	0	50
	Marionville DS	Core South	2026	2026	10	10
	Kanata MTS	Kanata-Stittsville	2024	2026	20	40
	South March TS	Kanata-Stittsville	2027	2027	20	100
Medium Term	Overbrook TS	Core East – Pocket 2	-	2032	0	90
	Hawthorne TS	Core East – Pocket 2	-	2031	0	60
	Hinchey TS	Core West – Pocket 2	-	2033	0	60
	Nepean TS	Kanata-Stittsville	-	2031	0	100
Long Term	Merivale MTS	Core East – Pocket 2	-	2039	0	7
	Uplands MTS	Core East – Pocket 2	-	2041	0	5
	Albion TS	Core East – Pocket 2	-	2035	0	40
	Cambrian MTS	Core West – Pocket 1	-	2038	0	20
	Richmond South MTS	Core West – Pocket 1	-	2037	0	10
	Terry Fox MTS	Core West – Pocket 1	-	2037	0	30
	Lincoln Heights TS	Core West – Pocket 2	-	2040	0	10
	Woodroffe TS	Core West – Pocket 2	-	2040	0	10

The Kanata-Stittsville subsystem was found to be limited by voltage stability issues due to the loss of either M32S or C3S, where M32S is more limiting. With M32S on outage it was found that the next most impactful contingency is the loss of C27P which results in an LMC of 315 MW for the subsystem.

The Core West subsystem was found to be limited by thermal overloads on C7BM and F10MV. The loss of either circuit transfers the entirety of the load from Woodroffe TS and Lincoln Heights TS onto the remaining circuit. The loss of F10MV was found to be more limiting causing a thermal overload on sections of C7BM at combined station loads of 230 MW. Further, an E34M contingency leads to thermal overloads on sections of S7M due to the Fast Transfer Scheme that transfers Cambrian MTS onto S7M. This occurs at combined station loads of 250 MW.

The Core East subsystem was found to be limited by thermal overloads on M5G and M4G when the companion circuit is lost as both Lisgar TS and Carling TS would fully be supplied by the remaining circuit. It was found that a contingency to M5G was more limiting leading to an LMC of 223 MW. The Core East subsystem Pocket 2 has a combined station LTR of approximately 600 MW which is not exceeded in the summer forecast but is greatly exceeded in the winter forecast. Under the current system the winter forecast cannot be accommodated without experiencing voltage stability issue. However, the winter forecast is not certain and the work required to improve the 115kV system involves the plan to recommend expansions and several stations as interim measures while the TWG continues to develop long-term plans for the area.

The Core South subsystem is limited by a load security need followed by thermal overload and L2M at a load of 140 MW in the summer and 165 MW in the winter amongst the five stations in the subsystem. The limit is only exceeded in the winter forecast.

Load Security

Kanata-Stittsville Area:

With respect to single contingency assessment, Nepean TS winter load growth is forecasted to exceed 150 MW by 2029. Since M32S is the sole supply to the Nepean TS, an outage or contingency to M32S would lead to the loss of 150 MW or more. Furthermore, when both M32S and C3S are lost, all stations supplied by the circuits will lose more than 600 MW in the 20-year winter forecast, which is a load security violation.

Core South Area:

With respect to one contingency event, which causes both L2M and M1R to go on outage, the maximum allowable load to be lost by configuration is 150 MW. The Core South area exceeds this limit in 2031 in the winter, and does not exceed this limit in the 20-year summer forecast.