Ottawa Sub-Region:

Integrated Regional Resource Plan

- Appendices

Part of the Greater Ottawa Regional Planning Region

March 4, 2020

Connecting Today.
Powering Tomorrow.

Appendix A: Overview of the Regional Planning Process

A.1 THE REGIONAL PLANNING PROCESS

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

Regional planning has been conducted on an as-needed basis in Ontario for many years. 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[1], 21 electricity planning regions, a new regional planning process, and a schedule for completion of regional plans.

The regional planning process begins with a needs assessment 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 Integrated Regional Resource Plan (IRRP), which considers energy efficiency, 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.

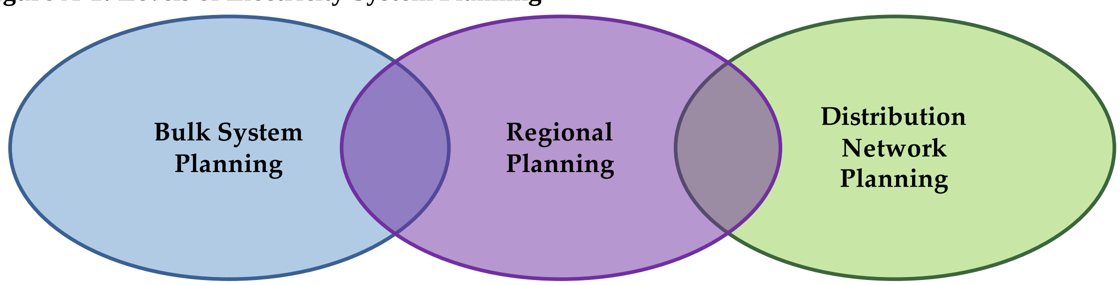
There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the scoping assessment, the IESO produces a report that includes the results of the needs assessment process and preliminary terms of reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within

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

18 months. If an RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. Draft scoping assessment outcome reports must be posted to the IESO's website for a two-week public comment period prior to finalization.

The final needs assessment report, scoping assessment report, IRRP and RIP, as applicable, are posted on the websites of the IESO and relevant transmitter(s), 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 energy efficiency 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. As shown in Figure A-1, regional planning is only one of three types of electricity system planning carried out in Ontario.

Figure A-1: Levels of Electricity System Planning



Bulk System Planning

- 500 kV & 230 kV transmission
- Interconnections
- Inter-area network transfer capabilities
- System reliability (security and adequacy) to meet NERC, NPCC, ORTAC
- Congestion and system efficiency
- System supply and demand forecasts
- Incorporation of large generation
- Typically medium- and long-term focused

Regional Planning

- 230 kV & 115 kV transmission
- 115/230 kV autotransformers and associated switchyard facilities
- Customer connections
- Load supply stations
- Regional reliability (security and adequacy) to meet NERC, NPCC & ORTAC
- ORTAC local area reliability criteria
- Regional/local area generation & CDM resources
- Typically near- and medium-term focused

Distribution Network Planning

- Transformer stations to connect to the transmission system
- Distribution network planning (e.g. new & modified DX facilities)
- Distribution system reliability (capacity and security)
- Distribution connected generation and CDM resources
- LDC demand forecasts
- Near- and medium-term focused

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 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, making it important for regional planning to be coordinated with both bulk and distribution 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 takes into account the interests of ratepayers and individual large customers. IRRPs evaluate the options available to meet the needs, including energy efficiency, generation, and "wires" solutions. Through both engagements, which are embedded into regional planning, and the subsequent publication of resulting plans, the IESO demonstrates its commitment to transparency throughout the process.

A.1.1 The IESO's Approach to Regional Planning

In assessing electricity system needs for a region over a 20-year period, IRRPs enable near-term actions to be developed in the context of a longer-term view of trends. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

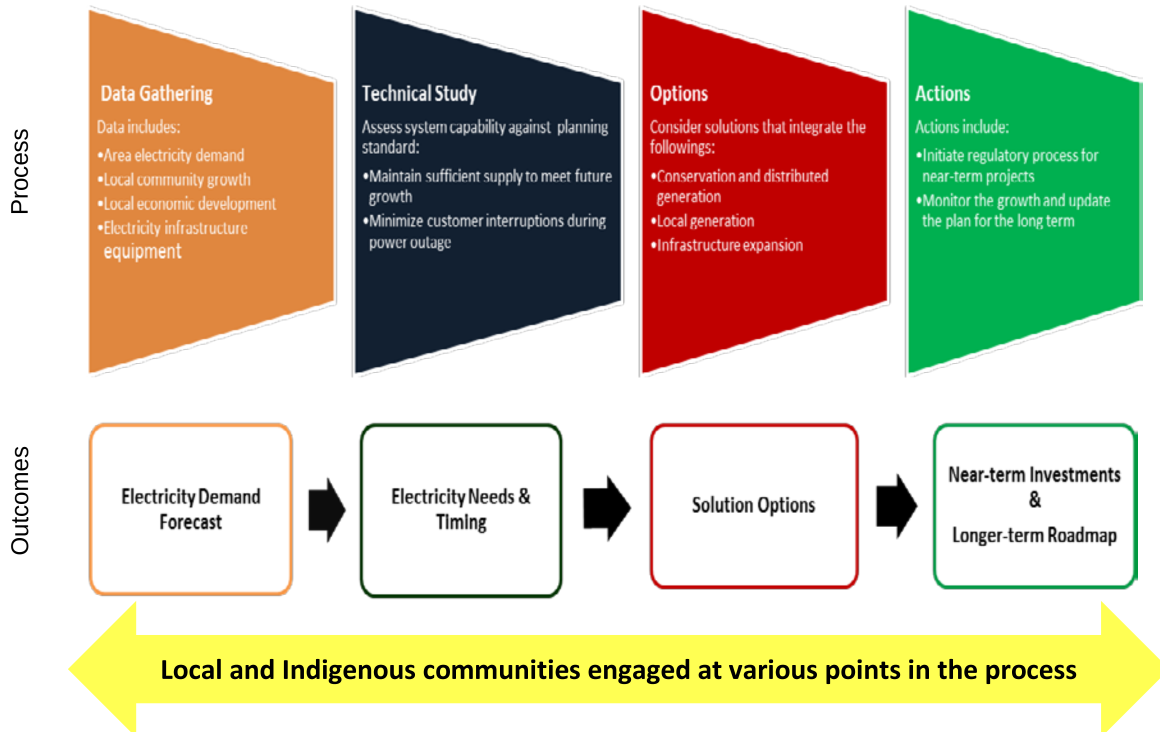
The IRRP describes the study team's recommendations for mitigating reliability and cost risks related to end-of-life asset replacement and demand forecast uncertainty associated with large load customers or due to changes in provincial energy efficiency targets. The IRRP helps ensure that recommendations to address near-term needs are implemented, while maintaining the flexibility to accommodate changing long-term conditions.

In developing an IRRP, the IESO and the study team a clearly defined series of steps (see Figure A-2), including:

- Developing electricity demand forecasts;
- Conducting technical studies to determine electricity needs and the timing of these needs;
- Considering potential options; and
- Creating a plan with recommended actions for the near and long term.

Throughout this process, engagement is carried out with stakeholders and Indigenous communities with an interest in the area.

Figure A-2: Steps in the IRRP Process



The IRRP report documents the inputs, findings and recommendations developed through this process, and outlines recommended actions for the various entities responsible for plan implementation. Where "wires" solutions are included in the recommendations, the completion of the IRRP triggers the initiation of the transmitter's RIP process to develop those options. Other recommendations in the IRRP may include: development of energy efficiency, local generation, community engagement, or information gathering to support future iterations of the regional planning process in the region or sub-region.

Appendix B: Demand Outlook and Methodology

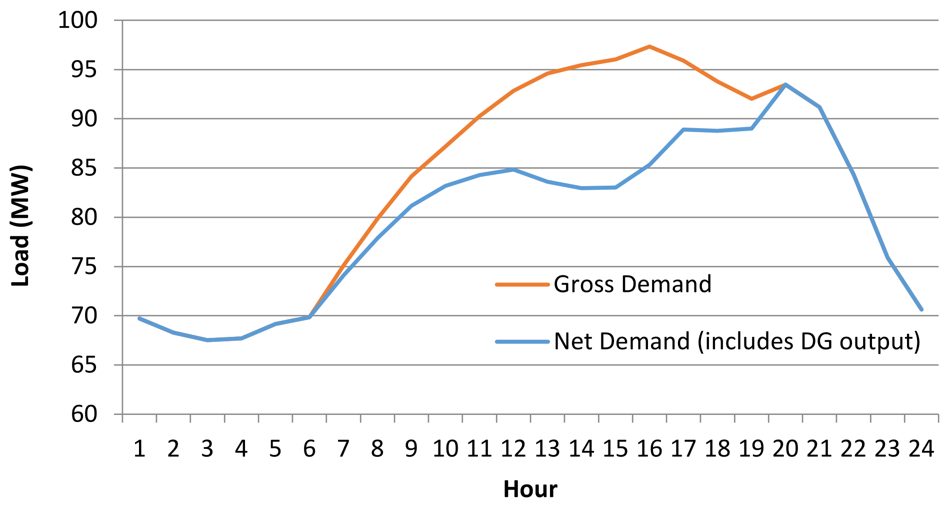
B.1 GROSS HISTORICAL LOAD

In this IRRP, the IESO determined the weather-corrected gross demand to act as a forecast starting point for the LDCs. As the metered historical data only represents net demand, the methodologies for adding the effects of distributed generation and estimating the impact of energy efficiency are described below.

B.1.1 Historical Distribution Generation Contribution

While the IESO collects hourly output data for renewable generation, this is typically for transmission-connected facilities – not distribution-connected. Therefore, to estimate the generation profile of these facilities, the output of select monitored facilities was scaled to represent *all* contracted facilities in the area. For the Ottawa Sub-Region IRRP in particular, this was done only for distribution-level solar resources, as data for hydroelectric facilities was unavailable. This assumes that within an area or region, the local weather conditions and output of the distributed generation resource are similar and comparable. As illustrated in Figure B-1, adding the estimated hourly distributed generation contribution can alter the demand profile and potentially change the time of the peak.

Figure B-1: Sample Profile Before and After Adjusting for Distributed Generation



B.1.2 Estimated Energy Efficiency Savings Impact

Historical conservation energy savings can be divided into three parts:

a) Participation in the conservation programs delivered by the LDCs

b) Estimated impact of historical codes and standard improvement

c) Estimated impact of behavioral changes due to Time-of-Use rates

Note that demand reduction resulting from the Industrial Conservation Incentive program was not included in this step. For other energy efficiency measures, the impact on local hourly demand was estimated by scaling the provincial-level savings to the region/station. For instance, peak-demand reduction from conservation program participation was allocated to the region/station by postal code mapping. On the other hand, both codes and standards and time-of-use savings had *estimated* hourly savings and were allocated from the system level to the region/station.

B.2 WEATHER CORRECTION

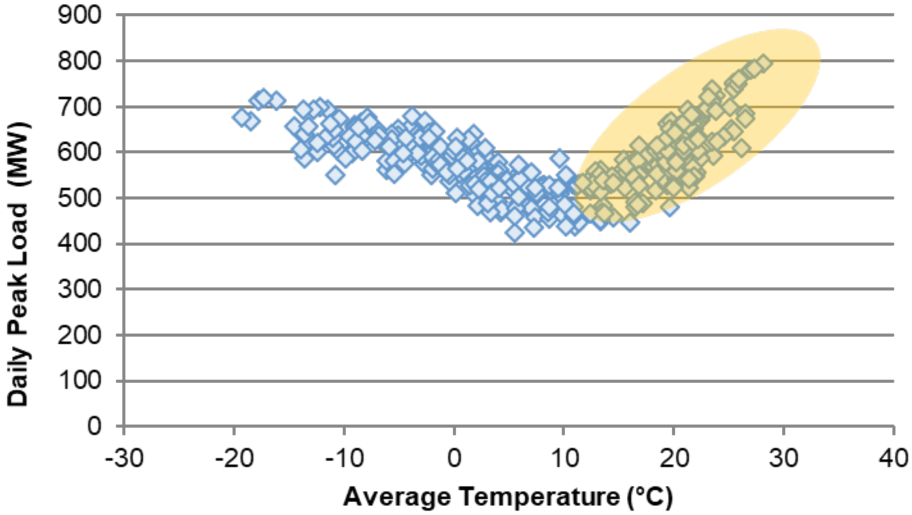
Since peak demand is sensitive to weather conditions, weather correction or normalization aims to establish the peak demand at a defined weather condition (median or extreme). Weather correction can occur at the station level, but for this IRRP, it was assumed that stations located closely within a geographical area would experience similar weather and exhibit similar weather-load patterns. Hence, weather correction occurred according to three areas: West Ottawa, Central Ottawa, and East Ottawa. The stations in each area are first defined in Table B-3.

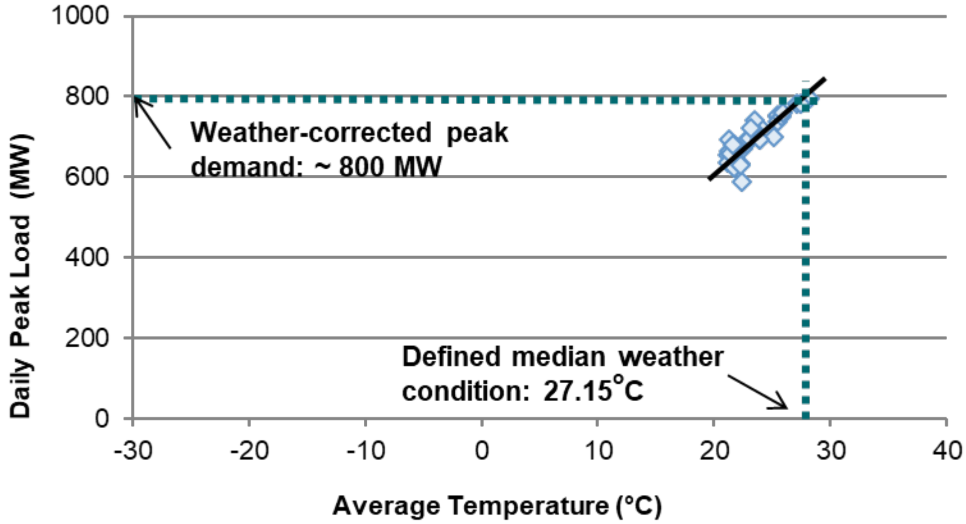
Median weather conditions for the Ottawa Sub-Region was defined to be 27.15 °C. This temperature was the median value of the maximum average daily temperatures for the past 31 years.

Extreme weather conditions for the Ottawa Sub-Region was defined to be 29.7 °C. This temperature was in the 97th percentile of the maximum average daily temperatures for the past 31 years.

After defining median and extreme weather, a linear regression was performed, for each historical year of interest, between gross daily peak loads and daily peak temperatures. Weekends and holidays were not included in this data set. Because the Ottawa Sub-Region is summer-peaking, data corresponding to temperatures below 21 °C were also omitted. The median temperature was then used with the linear regression to establish the weather-corrected gross peak demand for that year. This process is summarized in Figure B-2.

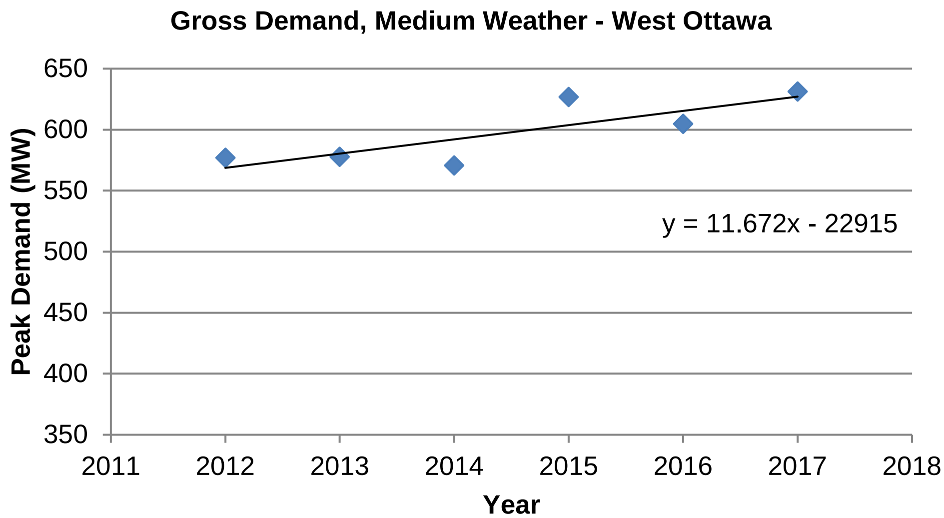
Figure B-2: Linear Regression to Weather-Correct Historical Peak Demand

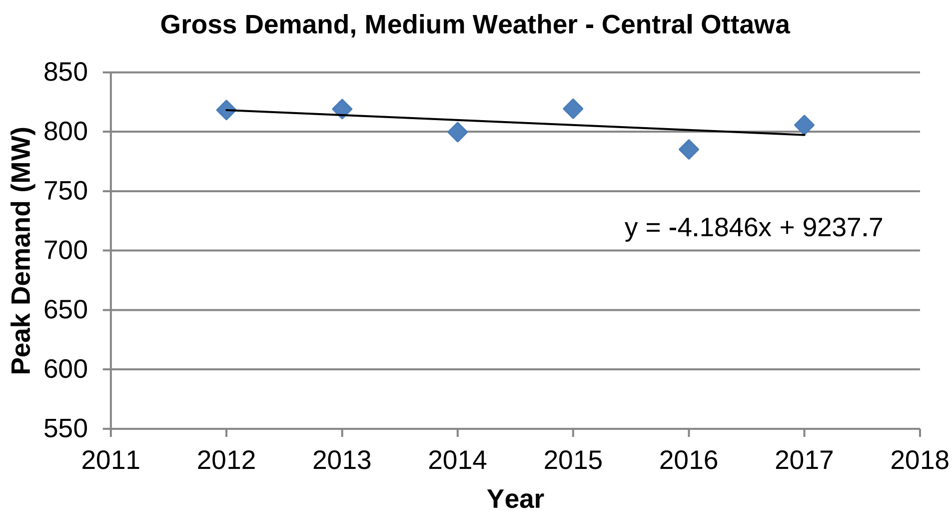


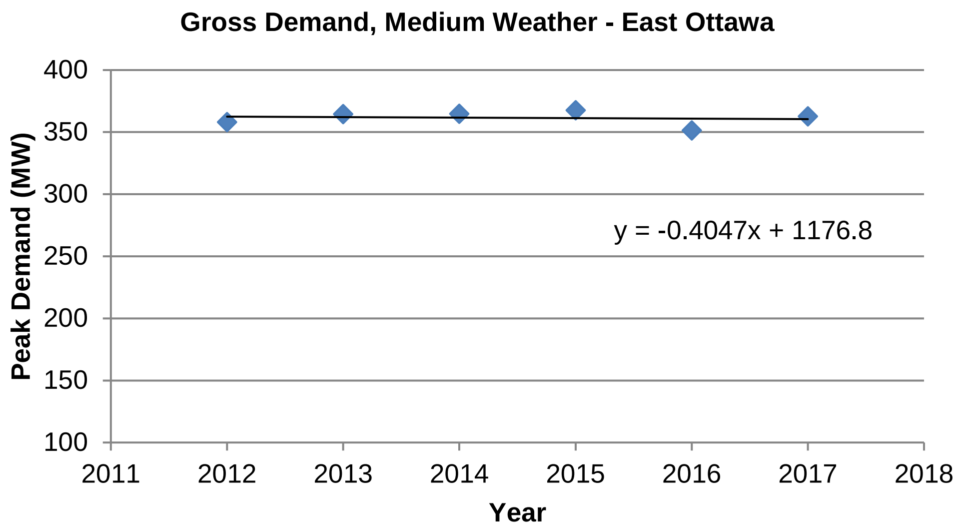


Once the gross peak demands for the past five years were weather-corrected for each area to reflect median temperatures, another linear regression was performed to establish the forecast starting point. This is shown in Figure B-3 for West Ottawa, Central Ottawa, and East Ottawa.

Figure B-3: Linear Regression with Median Weather-Corrected Gross Peak Demand to Establish Forecast Starting Points







For the Ottawa Sub-Region IRRP (which began in 2018), the starting points were based upon the 2017 year. They are shown in the following table.

Table B-1: Forecast Starting Points (Base Year 2017) for Each Area in the Ottawa Sub-Region

West Ottawa	Central Ottawa	East Ottawa
627.4 MW	797.4 MW	360.5 MW

Extreme weather correction was not applied until *after* 20-year net-demand forecasts were determined. The average ratio (for each area) between the median and extreme weather-corrected peak demands from 2012-2017 was calculated (see Table B-3). This was then applied to the 20-year net-demand forecast.

Table B-2: Extreme Weather Correction Factor for Each Area in the Ottawa Sub-Region

West Ottawa	Central Ottawa	East Ottawa
1.09	1.07	1.08

B.3 HYDRO OTTAWA: GROSS FORECAST METHODOLOGY AND ASSUMPTIONS

Hydro Ottawa was formed in November 2000, following the amalgamation of five municipally-owned electric utilities (Gloucester Hydro, Goulbourn Hydro, Kanata Hydro, Nepean Hydro and Ottawa Hydro) from the former region of Ottawa-Carleton and the restructuring of the

Ontario electricity sector as a result of the Electricity Act, 1998. In 2002, Casselman Hydro was acquired by Hydro Ottawa and joined the amalgamated utility.

As of the end of 2019, Hydro Ottawa distributes electricity to approximately 340,000 metered customers within the City of Ottawa and the Village of Casselman. The service area covers 1,116 square kilometers and is supplied by an even mix of overhead and underground distribution lines. In 2018, Hydro Ottawa purchased a total of 7,446 gigawatt hours of electricity from the provincial grid to supply to customers. The Hydro Ottawa system peaks in the summer at a level that has remained relatively constant (maximum of 1,518 MW in 2010 and minimum of 1,308 MW in 2014) over the past decade. While population growth continues to increase, reductions from conservation programs, improvements in appliance efficiencies, and the installation of ERFs have offset the demand requirements of intensification. As the City grows, former rural areas fed by long distribution lines are becoming urban centres. This has created a new dynamic of customer requirements for higher reliability.

Overall, the City of Ottawa continues to grow in population and developed lands. The Ottawa-Gatineau population has consistently grown by 22,000 (1.5%) residents annually since 2015. On the Ottawa side, this development is primarily focused in five regions: the Downtown Core, Nepean & Riverside South, South Kanata & Stittsville, the Village of Richmond, and Orleans. This growth is being seen through the development of new mixed commercial/residential communities, intensification of existing communities, and major projects like the Ottawa LRT system.

Growth Identification

An important predecessor to load forecasting is the ability to identify areas of potential load growth. To ensure that Hydro Ottawa can continue to supply existing and new growth through its service territory, two primary processes are used to identify growth: the City of Ottawa's development application process and Hydro Ottawa's service request process.

City of Ottawa's Development Application Process

Hydro Ottawa is actively engaged in the City of Ottawa's development application process which allows for input and understanding of the City's land use policy through the Official Plan and supporting plans such as community design plans, transportation master plan, and infrastructure master plan. Changes to land use policy will typically have a long-term impact (i.e., greater than five years) on growth opportunities and be more wide reaching throughout the City of Ottawa. Hydro Ottawa is also actively engaged in the implementation of the land use policies by reviewing site plans, subdivision plans, and zoning amendments. Proposals from the implementation of the land use policies are typically short term (one to two years) to medium term (two to five years), and are localized to specific areas of the City.

Service Request Process

The service request process consists of developers requesting connection to Hydro Ottawa's system. These can range from general services and residential services to commercial service and large developments. These developments include connection requests for projects previously identified through the development application process.

Hydro Ottawa works closely with developers within its service territory to support early identification of required service size and timing of line additions or expansion within these growth areas. This engagement enables these developments and supports Hydro Ottawa load forecasting for capacity investment planning.

Load Forecasting

Load forecasting identifies how load will increase at the system level using information from identifying growth opportunities, historical growth and historical weather patterns. Forecasted load is established at the feeder level and aggregated by station on an annual basis to evaluate the loading impact with respect to equipment limitations and system constraints.

B.4 HYDRO ONE DISTRIBUTION: GROSS FORECAST METHODOLOGY AND ASSUMPTIONS

Hydro One Networks Distribution distributes electricity to customers at 69kV and below around the outer boundary of the City of Ottawa, except for, Stittsville/Carp, Pierces Corners, Osgoode, Manotick, Greely, Russell and Orleans/Queenswood. Hydro Ottawa Limited predominantly services the City of Ottawa.

Hydro One services about 44,000 customers in this region primarily through overhead lines with the exception of Orleans/Queenswood which is predominantly underground.

Factors that Affect Electricity Demand

In the last 5 years, the City of Ottawa and surrounding areas have experienced a high rate of growth as a result of residential, commercial and industrial load growth. Generation and conservation demand management has had impact on forecasting peak demand resulting in deferral of certain investments.

Notice of large customers beginning to adopt onsite battery storage or natural gas generation with the intent to fully operate as an island to minimize and/or shifting of hourly peak demand for financial benefits.

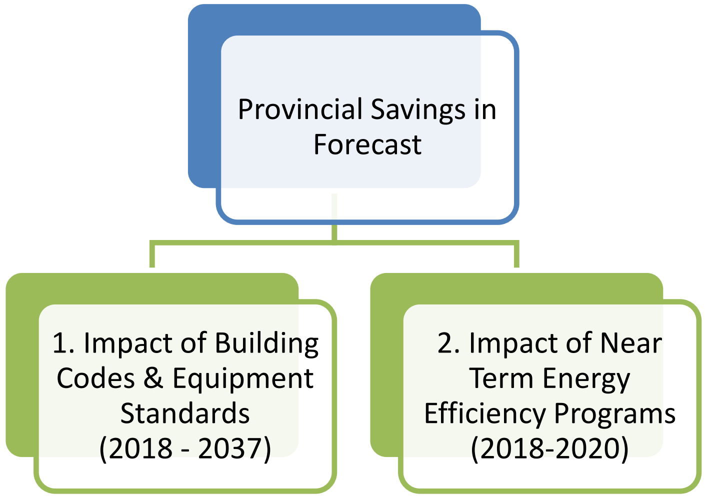
Forecast Methodology and Assumptions

Hydro One has a dedicated team that monitors the system load and provides updated load forecasts when required. Forecasts are provided for the next 20 years and factor in demand from recent connection requests and municipal plans. Additional considerations include economic forecasts, conservation demand management and historical weather patterns.

B.5 ENERGY EFFICIENCY FORECAST IN THE OTTAWA IRRP

As shown in Figure B-1, the impact of already existing or committed energy efficiency measures can be separated into the two main categories: Building Codes & Equipment Standards, and already committed (Near Term) Energy Efficiency Programs. The savings for each category are allocated according to the forecast residential, commercial, and industrial gross demand. This appendix section provides additional breakdowns of estimated energy efficiency savings for the Ottawa region and more detail on how the savings for the two categories were developed.

Figure B-4: Existing or Committed Energy Efficiency Savings Categories

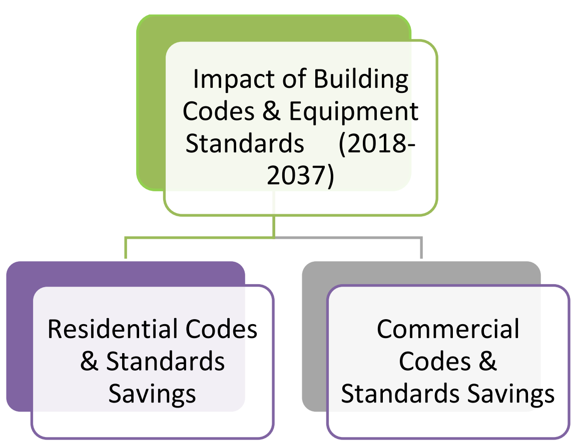


1. *Savings due to building codes and equipment standards*
2. *Savings due to the delivery of energy efficiency programs*

B.5.1 Estimating Savings from Building Codes and Equipment Standards

Ontario building codes and equipment standards set minimum efficiency levels through regulations. To estimate the impact on the region, the associated peak-demand savings for building codes and equipment standards are estimated and compared with the provincial gross peak-demand forecast. From this comparison, annual savings percentages are developed for the purpose of allocating the associated savings to each TS in the region by sector.

Figure B-5: Split of Building Codes & Equipment Standards Savings



**Savings are projected for residential and commercial sectors only*

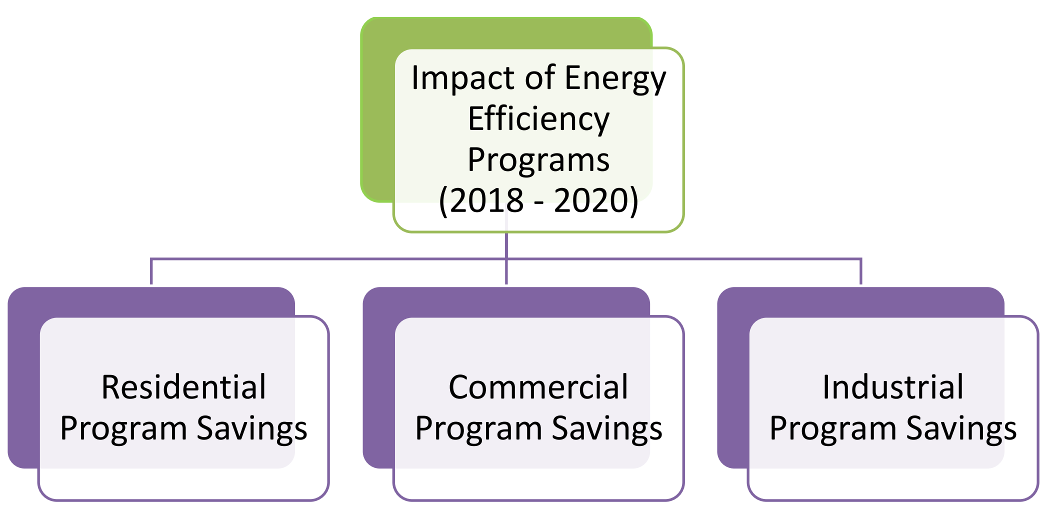
Annual savings percentages were applied to the forecast sector demand at each TS to develop an estimate of peak-demand impacts from codes and standards. By 2037, the residential sector in the region is expected to see about 7.2 per cent peak-demand savings through standards, while the commercial sector will see about 4.8 per cent peak-demand savings through codes.

B.5.2 Estimating Savings from the Delivery of Existing or Committed Energy Efficiency Programs (2018-2020)

Estimates of the peak-demand impacts of existing or committed energy efficiency programs across the province are included in the regional planning forecast. This differs from the evaluation of future Energy Efficiency Potential, which is presented in Appendix D.

Though the Conservation First Framework (CFF) has been transitioned to the Interim Framework, which runs from March 2019 until December 31, 2020, at the time the forecast for this IRRP was developed, CFF was still in place. To represent savings from energy efficiency measures that have been recently implemented but not yet captured in the reference forecast as well as programs for which funding has been committed but not yet spent, this IRRP uses the LDCs' CDM plans that were developed under CFF. Specifically, these plans were used to estimate the expected savings in the region from energy efficiency programs implemented for the short term (2018 -2020). Each CDM plan includes detailed savings projections from energy efficiency and funded behind-the-meter generation projects, and indicates how energy efficiency efforts will integrate with regional planning. The forecast savings were allocated to the region and TSs according to their respective load.

Figure B-6: Time Frames for Energy Efficiency Program Savings



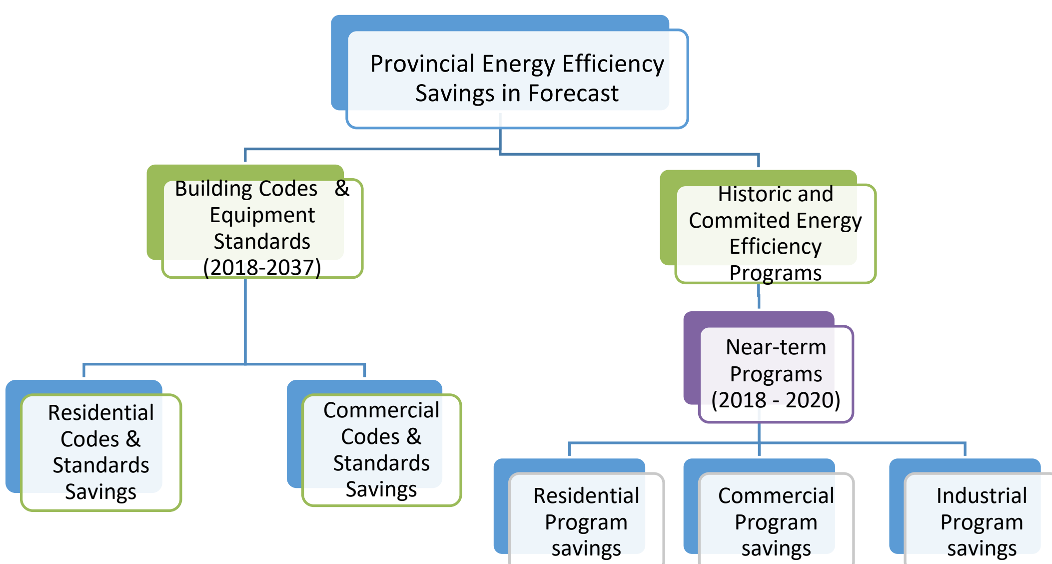
Persistence of these peak-demand savings from energy efficiency programs delivered between 2018-2020 are also considered over the forecast period. The peak-demand savings were estimated using the CDM plans projected summer-demand savings. On future IRRP studies, estimates developed through the Interim Framework will be used to approximate the conservation impact expected from short-term energy efficiency programs.

The portion of an LDC's service territory associated with this IRRP will directly relate to the savings estimated to occur in the region. In other words, the LDC's energy efficiency savings in the region are assumed to be proportional to the amount of its energy within the region (e.g., if 60 per cent of an LDC's energy is served in this region, then 60 per cent of the expected forecast savings for that LDC are estimated to occur within this sub-region). When the total peak-demand savings for the region has been estimated, it is allocated at each TS according to the relative share of residential, commercial, and industrial gross demand.

B.5.3 Energy Efficiency Savings assumed in the Planning Forecast

As described in the above sections, peak-demand savings were estimated by sector for each forecast category, and totaled for each TS in the region. The analyses were conducted under normal weather conditions and can be adjusted to reflect extreme weather conditions. The resulting forecast savings, along with the impact of distributed generation resources, were applied to gross demand to determine the net peak demand for further planning analyses.

Figure B-7: Map of Existing & Committed Energy Efficiency Savings



B.5.4 Forecast Savings from Existing and Committed Energy Efficiency

The forecast peak-demand savings from existing and committed energy efficiency is shown in Table B-3: Summer Peak-Demand Savings (MW) by TS. The savings are based on the LDC median gross forecast. Energy efficiency forecast estimates are based on the assumptions associated with the building codes and equipment standards impacts and near-term energy efficiency program delivery described in the previous sections.

Table B-3: Summer Peak Demand Savings (MW) by TS

Expected Summer Peak-Demand Contribution from Contracted Distributed Generation (MW)																					
	Station	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
West Ottawa	Bridlewood MTS	0.3	0.4	0.5	0.5	0.5	0.6	0.7	0.8	0.9	1.1	1.2	1.3	1.3	1.4	1.5	1.5	1.6	1.6	1.6	1.6
	Marchwood MTS	1.9	2.4	2.8	2.5	2.7	2.9	3.1	3.5	3.6	3.8	3.9	4.3	4.5	4.7	5.0	5.2	5.2	5.2	5.2	5.1
	Fallowfield DS	1.9	2.1	2.4	2.3	1.5	1.7	1.7	1.7	1.8	1.9	2.0	2.2	2.2	2.4	2.5	2.7	2.6	2.5	2.5	2.5
	Manotick DS	0.2	0.4	0.5	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8
	Richmond DS	0.2	0.4	0.6	0.6	0.8	1.0	1.2	1.3	1.4	1.5	1.5	1.6	1.7	1.8	1.9	2.0	2.0	2.1	2.1	2.0
	Manordale MTS	0.3	0.4	0.5	0.5	0.5	0.5	0.4	0.4	0.3	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Limebank MTS	2.0	2.5	3.2	2.9	3.2	3.3	3.7	3.8	4.1	4.5	5.0	5.6	6.3	7.1	7.8	8.2	8.5	8.7	8.8	8.9
	Marionville DS	0.5	0.6	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	1.0	1.0	0.9	0.9	1.0	1.0	1.0
	Uplands MTS	0.9	1.2	1.4	1.3	1.5	1.8	2.1	2.7	2.9	2.9	3.1	3.5	3.6	3.9	4.2	4.4	4.4	4.5	4.5	4.5
	South Gloucester DS	0.2	0.2	0.3	0.2	0.2	0.3	0.3	0.3	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4
	Greely DS	0.8	1.0	1.1	1.1	1.0	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.5	1.6	1.6	1.6	1.6	1.6	1.6
	Russell DS	0.2	0.2	0.3	0.2	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Centerpoint MTS	0.6	0.7	0.8	0.7	0.8	0.7	0.8	0.9	0.9	1.0	0.9	1.0	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2
	Merivale TS	0.6	0.8	1.2	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.4	1.4	1.5	1.5	1.5	1.5	1.6	1.6	1.6
	National Aeronautical CTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Kanata MTS	2.3	2.8	3.3	3.0	3.1	3.3	3.5	3.6	3.9	4.0	4.1	4.5	4.7	4.9	5.2	5.3	5.3	5.2	5.2	5.2
	South March TS	3.7	4.7	5.5	5.1	5.3	5.6	5.7	6.0	6.2	6.3	6.2	6.4	6.7	6.9	7.2	7.4	7.4	7.3	7.3	7.3
	Nepean TS	5.9	7.2	7.8	7.2	6.9	7.2	7.5	7.8	8.0	8.3	8.4	8.8	9.1	9.4	9.9	10.0	10.0	9.8	9.8	9.7

Expected Summer Peak-Demand Contribution from Contracted Distributed Generation (MW)																					
	Station	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
	Terry Fox MTS	2.3	2.8	3.2	2.9	3.0	3.3	3.5	3.8	4.1	4.4	4.6	5.0	5.4	5.9	6.4	6.5	6.6	6.5	6.5	6.5
	South Nepean TS	0.0	0.0	0.0	0.0	1.2	1.5	1.8	2.1	2.4	2.7	3.0	3.5	3.9	4.4	4.8	5.1	5.4	5.7	5.7	5.7
Central Ottawa	Nepean Epworth TS	0.4	0.5	0.6	0.6	0.6	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.7	0.8	0.8	0.8	0.8	0.8	0.8
	Carling TS	3.6	4.4	5.1	4.6	4.6	4.9	5.3	5.5	5.7	5.9	6.1	6.5	6.7	7.0	7.4	7.6	7.6	7.5	7.5	7.4
	Lincoln Heights TS	1.7	2.1	2.3	2.2	2.2	2.3	2.4	3.0	3.0	3.2	3.2	3.4	3.7	3.8	4.0	4.1	4.1	4.1	4.1	4.0
	Woodroffe TS	1.2	1.4	1.7	1.5	1.5	1.7	2.4	2.6	2.7	2.8	2.9	3.0	3.2	3.4	3.5	3.7	3.8	3.7	3.7	3.7
	Hinchey TS	1.9	2.4	2.9	2.8	2.9	3.1	3.3	3.6	3.9	4.0	4.2	4.5	4.9	5.1	5.5	5.8	5.9	6.0	6.1	6.1
	Slater TS	5.0	6.5	7.7	7.1	6.9	7.2	7.3	7.5	7.6	7.8	7.8	8.0	8.2	8.6	9.0	9.0	9.0	8.9	8.9	8.8
	Lisgar TS	2.6	3.3	3.8	3.5	3.7	3.9	4.1	4.3	4.5	4.9	5.0	5.3	5.6	5.9	6.2	6.4	6.4	6.4	6.5	6.5
	King Edward TS	3.5	4.4	5.1	4.7	4.6	4.9	5.2	5.4	5.6	5.8	5.9	6.2	6.5	6.8	7.1	7.2	7.3	7.2	7.1	7.1
	Russell TS	3.2	4.1	5.0	4.6	4.5	4.8	4.8	5.0	5.2	5.2	5.3	5.5	5.7	5.9	6.2	6.3	6.2	6.2	6.2	6.1
	Overbrook TS	2.6	3.2	3.8	3.5	3.6	3.9	4.2	4.5	4.7	5.0	5.1	5.5	5.8	6.2	6.6	6.8	6.9	7.0	7.0	7.1
	Riverdale TS	3.3	4.0	4.6	4.2	4.2	4.5	4.8	5.0	5.2	5.4	5.5	5.9	6.2	6.7	7.0	7.2	7.2	7.3	7.3	7.3
	Albion TS	2.4	2.7	3.1	2.8	2.8	3.0	3.2	3.3	3.4	3.5	3.5	3.8	4.0	4.2	4.4	4.5	4.5	4.4	4.4	4.4
	Ellwood TS	1.5	1.8	2.1	1.9	2.0	2.1	2.2	2.3	2.4	2.4	2.6	2.7	2.7	2.9	3.1	3.1	3.2	3.1	3.1	3.1
East Ottawa	Bilberry Creek TS	1.8	2.1	2.4	2.2	2.4	2.5	2.7	2.8	2.9	3.0	3.0	3.3	3.4	3.5	3.7	3.8	3.8	3.8	3.7	3.7
	Orleans TS	4.4	5.9	7.2	6.8	6.7	6.9	7.1	7.4	7.8	8.0	7.9	8.2	8.4	8.7	9.1	9.3	9.3	9.3	9.3	9.3
	Cyrville MTS	1.0	1.2	1.4	1.4	1.5	1.8	2.0	2.2	2.3	2.5	2.7	2.9	3.2	3.4	3.7	3.9	4.0	4.0	4.1	4.2
	Moulton MTS	1.0	1.2	1.4	1.3	1.4	1.6	1.6	1.8	1.9	1.9	1.9	2.1	2.2	2.3	2.4	2.5	2.5	2.5	2.5	2.5
	Wilhaven DS	0.2	0.2	0.3	0.2	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Navan DS	0.2	0.2	0.3	0.2	0.2	0.3	0.3	0.3	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4
	Cumberland DS	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hawthorne TS	4.5	5.7	6.6	6.1	6.3	6.8	7.1	7.6	8.0	8.4	8.7	9.3	9.9	10.5	11.1	11.6	11.9	12.0	12.1	12.1
	National Research TS	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total	**73**	**91**	**108**	**100**	**102**	**109**	**115**	**122**	**127**	**131**	**134**	**142**	**150**	**158**	**167**	**172**	**174**	**174**	**174**	**173**

B.6 EXPECTED PEAK DEMAND CONTRIBUTION OF CONTRACTED DISTRIBUTED GENERATION

The installed capacity of contracted distributed generation is adjusted to reflect the expected power output at the time of local area peak, based on resource-specific peak capacity contribution values. As of February 2019, distributed generation projects are expected to offset 64 MW of summer peak demand within the Ottawa Sub-Region by 2020. The distribution-connected contracted generators included in the forecast comprise a mix of solar and hydroelectric. The majority of these generators in the region are hydroelectric (75 per cent of contracted capacity), with solar accounting for 25 per cent of contracted capacity. Capacity contribution factors of 62 per cent and 30 per cent (hydroelectric and solar respectively) to the regional peak have been assumed to account for the expected output of the mix of local generation resources during summer peak conditions.

The expected peak-demand contribution of contracted distributed generation in the Ottawa Sub-Region is shown Table B-4.

Table B-4: Expected Summer Peak Demand Contribution from Contracted Distributed Generation[2]

Expected Summer Peak-Demand Contribution from Contracted Distributed Generation (MW)																					
	Station	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
West Ottawa	Bridlewood MTS	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.15	0.15	0.15	0	0	0
	Marchwood MTS	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0	0	0	0	0	0	0
	Fallowfield DS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Manotick DS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Richmond DS	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0	0	0	0	0	0
	Manordale MTS	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0
	Limebank MTS	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.04	0.01	0.01	0.01	0	0	0
	Marionville DS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Uplands MTS	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00	0	0	0	0	0	0
	South Gloucester DS	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0	0	0
	Greely DS	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.15	0.15	0
	Russell DS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Centerpoint MTS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Merivale TS	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0	0	0	0	0	0
	National Aeronautical CTS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Kanata MTS	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.01	0.01	0.01	0.01	0	0	0
	South March TS	0.58	0.58	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.49	0.38	0.38	0.38	0.13	0.13	0.08
	Nepean TS	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.35	0.11	0.11	0.11	0.03	0.03	0
	Terry Fox MTS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	South Nepean TS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Central Ottawa	Nepean Epworth TS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Carling TS	18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.22	18.20	18.20	18.20	18.20	18.20	18.20

[2] While the effective capacity of the total (both existing and new) installed distributed generation is shown in this table, note that peak savings from **existing** hydroelectric facilities were not subtracted from the gross forecast. Gross forecasts provided by LDCs in the Ottawa Sub-Region already included existing distributed hydroelectric output; the relevant generation output data was not available to create a gross starting point with existing hydroelectric peak demand savings added.

Expected Summer Peak-Demand Contribution from Contracted Distributed Generation (MW)																					
	Lincoln Hights TS	0	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	Woodroffe TS	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.09	0.08	0.08	0.08	0.08	0.08	0
	Hinchey TS	0	0	16.74	16.74	16.74	16.74	16.74	16.74	16.74	16.74	16.74	16.74	16.74	16.74	16.74	16.74	16.74	16.74	16.74	16.74
	Slater TS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Lisgar TS	11.41	11.41	18.85	18.85	18.85	18.85	18.85	18.85	18.85	18.85	18.41	18.41	18.41	7.44	7.44	7.44	7.44	7.44	7.44	7.44
	King Edward TS	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	0.01	0	0	0	0	0	0
	Russell TS	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.53	0.07	0.07	0.07	0	0	0
	Overbrook TS	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.08	0	0	0	0	0	0
	Riverdale TS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Albion TS	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.24	0.15	0.15	0.15	0.08	0.08	0.08
	Ellwood TS	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.08	0.08	0	0	0
East Ottawa	Bilberry Creek TS	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.18	0	0	0	0	0	0
	Orleans TS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Cyrville MTS	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0	0	0	0	0	0
	Moulton MTS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Wilhaven DS	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.23	0.16	0.16	0.16	0	0	0
	Navan DS	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.12	0.12	0.12	0.12	0.00	0.00	0.00
	Cumberland DS	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0	0	0	0	0	0
	Hawthorne TS	3.66	3.66	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	0.77	0.62	0.49	0.49	0.49	0.37	0.18	0.18	0
	National Research TS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total	**40**	**40**	**64**	**64**	**64**	**64**	**64**	**64**	**64**	**64**	**64**	**61**	**60**	**46**	**45**	**45**	**44**	**43**	**43**	**43**

B.7 PLANNING PEAK DEMAND FORECAST

The planning forecast takes the gross median weather forecast data provided by the LDCs, accounts for the demand impacts of energy efficiency and DG, outlined in Appendix B.5 and B.4 respectively, considers regional peak coincidence, and adjusts for the impact of extreme weather conditions. Extreme weather correction was carried out according to the methodology previously described in Section B.2.

To evaluate the adequacy of the electric system, the forecasts consider demand observed at each station for the hour of the year when overall demand in the study area is its maximum. This is referred to as “coincident peak demand”. Typically, this represents the time when assets are most stressed and resources are most constrained. This differs from a non-coincident peak, which is measured by summing each station’s individual peak, regardless of whether each station’s peak occurs at a different time than the area’s overall peak. Within the Ottawa Sub-Region, the peak loading hour for each year typically occurs in mid-afternoon of the hottest weekday during summer, driven by the air conditioning loads of residential and commercial customers. The Working Group determined each station’s historical contribution to the area’s coincident peak to then predict future station loading during coincident peak times.

Table B-5 shows the summer planning demand forecast for each station in the Ottawa Sub-Region.

Table B-5: Summer Planning Peak-Demand Forecast for Station and Sub-Region

Summer Planning Peak-Demand Forecast (MW) – Station and Sub-Region																						
	Station	LTR / Planning Capacity (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
West Ottawa	Bridlewood MTS	23	14.3	14.2	14.1	15.1	15.0	16.0	16.0	16.5	19.0	21.0	21.8	21.7	21.7	21.6	21.5	21.5	21.4	21.4	21.6	21.6
	Marchwood MTS	30	58.1	63.6	65.6	67.4	68.7	69.4	70.1	70.8	71.4	71.1	71.0	70.6	70.4	70.1	69.9	69.7	69.7	69.7	69.8	69.8
	Fallowfield DS	23	47.2	41.5	48.4	51.9	21.9	25.3	25.8	26.8	27.2	28.3	28.7	30.7	31.2	32.4	32.3	33.2	33.3	33.3	33.3	33.4
	Manotick DS	8	6.7	7.5	8.4	9.3	10.2	11.0	11.9	11.9	11.9	11.8	12.0	11.9	12.2	12.0	12.1	12.1	12.2	12.2	12.3	12.2
	Richmond DS	68	7.2	12.4	14.1	18.5	22.6	25.9	27.7	27.6	29.3	29.3	29.3	29.2	29.1	28.9	28.8	28.8	28.8	28.8	28.8	28.8
	Manordale MTS	9	9.9	9.7	9.7	9.8	9.8	9.8	9.9	9.9	10.0	10.1	10.2	10.2	10.2	10.3	10.3	10.3	10.3	10.3	10.4	10.4
	Limebank MTS	59	54.1	60.3	72.9	76.1	83.8	77.0	80.3	76.2	79.6	84.8	89.9	94.9	99.8	104.5	108.5	111.7	114.3	117.0	119.7	122.4
	Marionville DS	14	12.3	12.3	12.4	12.7	12.8	13.0	13.1	13.2	13.3	13.4	13.5	13.6	13.6	13.7	13.7	13.8	13.9	14.0	14.1	14.1
	Uplands MTS	30	23.8	26.9	29.1	30.8	37.5	42.6	47.8	57.4	57.7	58.1	58.8	59.5	59.7	59.9	60.2	60.5	60.9	61.3	61.8	61.8
	South Gloucester DS	7	4.4	4.5	4.6	4.7	4.7	4.7	4.7	4.7	4.8	4.8	4.8	4.9	4.9	4.8	4.8	4.8	4.9	4.9	4.9	4.9
	Greely DS	27	18.7	18.9	19.3	19.7	20.0	20.3	20.5	20.8	20.9	21.1	21.3	21.6	21.6	21.7	21.8	22.0	22.3	22.4	22.8	23.0
	Russell DS	7	4.0	4.1	4.2	4.2	4.3	4.3	4.2	4.4	4.4	4.4	4.4	4.4	4.5	4.5	4.4	4.4	4.4	4.5	4.5	4.5
	Centerpoint MTS	13	16.1	16.3	16.2	16.3	16.3	16.3	16.2	16.1	16.1	16.0	16.1	16.0	15.9	15.9	15.8	15.7	15.8	15.8	15.8	15.8
	Merivale TS	23	16.8	16.6	19.4	19.7	19.7	19.8	20.4	20.8	21.0	21.6	22.1	22.1	22.0	21.9	21.9	22.0	22.0	22.9	22.9	22.9
	National Aeronautical CTS	1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	Kanata MTS	49	62.9	65.2	67.0	70.9	70.9	70.7	70.4	70.3	70.1	70.9	71.2	70.9	70.6	70.4	70.4	70.3	70.3	70.3	70.4	70.4
	South March TS	110	91.1	91.6	92.4	93.5	104.0	103.8	103.3	103.5	103.8	103.5	102.2	100.7	100.0	100.2	100.6	101.1	101.5	102.0	102.7	103.3
	Nepean TS	145	153.1	152.5	137.7	142.7	134.3	133.9	134.5	134.3	134.1	133.8	133.6	133.2	132.9	132.5	132.2	132.3	132.3	132.5	132.6	132.7
	Terry Fox MTS	81	61.7	66.6	68.2	70.4	72.3	73.9	75.6	77.3	79.0	80.6	82.3	83.8	85.3	86.7	88.2	88.0	88.0	88.0	88.0	88.1
	South Nepean TS	TBD	0.0	0.0	0.0	0.0	39.4	43.4	47.5	50.4	54.4	58.0	61.0	63.8	67.1	69.8	71.6	73.4	76.3	79.8	79.8	79.8
Central Ottawa	Nepean Epworth TS	13	11.7	11.6	11.5	11.6	11.5	11.6	11.6	11.5	11.5	11.4	11.4	11.4	11.3	11.4	11.3	11.3	11.3	11.3	11.3	11.3
	Carling TS	95	91.7	92.7	94.3	95.9	96.5	96.2	101.1	101.3	101.1	101.1	101.4	101.5	101.4	101.1	100.7	100.6	100.6	100.7	100.7	100.8
	Lincoln Hights TS	72	44.3	44.6	44.3	46.8	46.7	46.6	46.5	55.6	55.5	55.3	55.3	55.1	54.8	54.7	54.5	54.3	54.3	54.4	54.4	54.4
	Woodroffe TS	91	32.2	31.8	32.3	33.3	34.0	34.3	51.1	50.9	50.7	50.6	50.5	50.4	50.1	50.0	49.8	49.7	49.6	49.7	49.7	49.7

			Summer Planning Peak-Demand Forecast (MW) – Station and Sub-Region																			
	Hinchey TS	86	48.4	50.2	54.5	39.9	42.0	43.7	46.6	49.4	50.9	52.6	54.3	55.7	57.2	58.2	60.1	61.1	62.3	63.6	64.9	66.2
	Slater TS	194	124.6	124.5	123.3	123.9	124.1	123.8	123.7	123.4	123.3	123.2	123.1	122.9	122.7	123.4	123.0	122.9	122.9	123.1	123.1	123.1
	Lisgar TS	75	70.6	69.9	70.2	63.3	70.0	70.2	71.5	71.8	72.3	75.5	76.0	76.3	76.5	77.8	78.0	78.3	78.9	79.4	80.0	80.6
	King Edward TS	82	91.0	90.2	91.4	92.7	93.5	93.9	94.4	95.0	95.5	96.1	96.7	97.1	97.6	97.3	96.9	96.8	96.7	96.9	96.9	96.9
	Russell TS	70	78.7	80.6	84.5	85.0	85.2	85.2	85.4	85.1	85.0	84.9	84.8	84.6	84.4	84.2	84.0	84.4	84.4	84.5	84.6	84.6
	Overbrook TS	95	67.0	71.2	74.4	77.1	78.8	81.0	83.2	85.1	85.8	86.8	87.6	88.6	89.1	90.1	90.7	92.0	92.7	94.0	95.0	96.2
	Riverdale TS	106	85.1	84.0	84.9	87.3	89.2	90.1	90.6	91.2	91.8	92.3	92.9	93.3	93.7	95.3	95.7	96.2	97.1	97.8	98.5	99.2
	Albion TS	89	58.2	57.8	57.5	58.0	58.2	58.1	58.1	58.0	58.1	58.2	58.2	58.1	58.1	58.0	58.1	58.2	58.3	58.6	58.8	58.8
	Ellwood TS	45	38.2	38.9	39.2	40.6	41.4	41.9	41.9	41.8	41.6	41.6	41.5	41.4	41.3	41.1	40.9	41.0	40.9	41.0	41.1	41.6
East Ottawa	Bilberry Creek TS	85	41.5	41.2	41.5	48.1	51.9	51.8	51.6	51.5	51.4	51.2	51.2	51.0	50.8	50.7	50.8	50.9	50.9	50.9	51.0	51.0
	Orleans TS	117	103.1	104.7	107.1	109.9	112.6	115.0	117.1	119.4	123.0	126.1	128.0	129.1	130.1	130.8	131.3	132.1	133.0	134.0	134.4	134.9
	Cyrville MTS	45	24.1	24.4	27.4	33.1	36.3	39.2	43.6	44.8	46.5	47.7	48.6	49.5	50.2	51.0	51.8	52.7	53.5	54.8	56.0	57.0
	Moulton MTS	30	27.5	27.3	29.0	31.1	33.0	34.7	34.7	34.5	34.4	34.4	34.3	34.1	34.1	33.9	33.8	33.7	33.7	33.7	33.7	33.7
	Wilhaven DS	18	3.3	3.3	3.4	3.5	3.5	3.5	3.6	3.6	3.6	3.6	3.6	3.7	3.7	3.7	4.0	4.1	4.1	4.2	4.3	4.3
	Navan DS	14	3.5	3.5	3.6	3.7	3.7	3.8	3.8	3.8	4.0	4.0	3.9	4.0	4.0	4.0	4.4	4.4	4.4	4.5	4.7	4.9
	Cumberland DS	7	5.4	5.5	5.5	5.6	5.7	5.7	5.8	5.8	6.0	6.1	6.3	6.4	6.5	6.5	6.6	6.6	6.8	6.8	6.9	6.9
	Hawthorne TS	137	123.1	121.5	120.5	123.5	130.3	133.7	134.4	136.2	138.0	141.8	146.0	148.3	153.8	155.6	157.3	159.7	162.8	165.4	168.1	169.6
	National Research TS	25	9.1	9.0	8.9	8.9	8.9	8.9	8.9	8.9	9.0	9.1	9.2	9.2	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
	Total		**1846**	**1874**	**1914**	**1957**	**2026**	**2054**	**2109**	**2142**	**2168**	**2197**	**2220**	**2236**	**2254**	**2271**	**2282**	**2296**	**2312**	**2330**	**2344**	**2356**

Appendix C: Planning Study Report

C.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 Sub-Region. The results of this planning study were used to inform the development of planning recommendations in the 2019 Ottawa IRRP.

C.2 FACILITY RATINGS ASSUMPTIONS

Scenarios assumed a load consistent with summer conditions and therefore summer planning ratings are assumed. Winter planning scenarios were not assessed.

Facility rating assumptions are summarized in the sub-sections that follow.

C.2.1 Transformer Ratings

Transformer ratings are summer planning ratings as registered with the IESO by the facility owner.

The long-term emergency (LTE) ratings of transformers are 10-day limited time ratings. The short-term emergency (STE) ratings of transformers are 15-minute limited time ratings.

C.2.2 Overhead Conductor Ratings

Transmission circuit overhead conductor ratings are as registered with the IESO by the facility owner.

The continuous rating is calculated as the amperage that maintains conductor temperature at 93 °C for aluminum conductor steel-reinforced (ACSR) conductors or sag (if lower) when the wind speed is less than 4 km/h and ambient temperature is 35 °C.

The long-term emergency rating is calculated as the amperage that maintains conductor temperature at 127 °C for ACSR conductors or sag (if lower) under the same ambient conditions described for the continuous rating.

The short-term emergency rating is calculated as the amperage that keeps conductor temperature less than 150 °C for ACSR conductors or sag (if lower) for 15 minutes, assuming that the circuit was initially loaded at its continuous rating.

C.3 DEMAND ASSUMPTIONS (STUDY AREA LOAD)

The planning study used the IRRP planning forecast shown in Appendix B, Table B-3. A power factor of 0.9 lagging was assumed for most stations as a reasonable worst-case assumption based on direction given by the Working Group.

C.4 SUPPLY ASSUMPTIONS

C.4.1 Run-of-River Hydroelectric Generation

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 for the of approximately 70MW for these generators.

C.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 C-1.

Table C-1: New Facilities Assumed in the Assessment

Facility	Description	Assumed in-service date
South Nepean Transmission Reinforcement	12.2 km extension of circuit E34M	2021
South Nepean MTS	New South Nepean MTS station tapped onto S7M (115kV) and E34M (230kV)	2022
M30A/M31A Conductor Upgrade	Upgrade existing 230kV circuits between Merivale TS and Hawthorne TS	2020
Overbrook TS – New 11kV tap to circuit A6R	Reconnect 115/13.8 kV transformer T1 at Overbrook Transformer Station (TS) from 115 kV circuit A4K to 115 kV circuit A6R through a new 1.9 km 115 kV tap line	2019

C.6 CREDIBLE PLANNING EVENTS

C.6.1 Steady State Planning Events Studied

For the purpose of this planning study, planning events were studied based on their applicability to bulk power system (BPS) elements, bulk electric system (BES) elements, or non-bulk elements. The steady state planning events are summarized in Table C-2.

Table C-2: Steady State Planning Events Studied

Pre-Contingency State	Contingency
All elements in-service	None
	Single element contingencies (N-1)
	Common tower contingencies (N-2)

C.7 PLANNING PERFORMANCE CRITERIA

The study applied planning performance criteria in accordance with the following standards and criteria:

- North American Electric Reliability Corporation (NERC) Standard TPL-001 – “Transmission System Planning Performance Requirements” (TPL-001),
- Northeast Power Coordinating Council (NPCC) Regional Reliability Reference Directory #1 – “Design and Operation of the Bulk Power System,” and
- IESO Ontario Resource and Transmission Assessment Criteria (ORTAC).

C.7.1 Load Supply Capacity

To 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.

C.7.2 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.

C.7.3 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 2037 forecast year are reported, with the collaboration of the Working Group.

C.8 STUDY RESULTS

C.8.1 Station Capacity Needs

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

Table C-3: Assessment of Station Capacity Over the Forecast Period

Station	LTR [MW]	Need Date	Station Load [MW]				Capacity Shortfall (MW)			
			2020	2025	2030	2037	2020	2025	2030	2037
Marchwood MTS	29.7	Near-Term	67.0	72.2	71.8	71.2	37.3	42.5	42.1	41.5
Fallowfield DS	22.5	Near-Term	49.9	28.3	32.6	34.8	27.4	5.8	10.1	12.3
Manotick DS	7.74	Near-Term	8.6	12.1	12.4	12.4	0.86	4.36	4.66	4.66
Manordale MTS	9	Near-Term	10.0	10.2	10.5	10.7	1	1.2	1.5	1.7
Limebank MTS	59.4	Near-Term	74.6	77.9	101.5	124.1	15.2	18.5	42.1	64.7
Uplands MTS	29.7	Near-Term	29.8	58.1	60.4	62.5	0.1	28.3	30.7	32.8
Centerpoint MTS	12.6	Near-Term	16.7	16.6	16.4	16.3	4.1	4	3.8	3.8
Kanata MTS	48.78	Near-Term	68.8	72.2	72.5	72.3	20.02	23.42	23.72	23.52
Terry Fox MTS	81	Medium-Term	69.9	79.0	87.1	89.9			6.1	8.9
Carling TS	95.4	Near-Term	97.0	104.0	104.1	103.5	1.6	8.6	8.7	6.1
Lisgar TS	74.7	Medium-Term	72.1	73.7	78.4	82.5			3.7	7.8
King Edward TS	82.35	Near-Term	94.0	97.6	100.2	99.5	11.65	15.25	17.85	17.15
Russell TS	70.02	Near-Term	86.9	87.5	86.7	87.0	16.88	17.48	16.68	16.98
Overbrook TS	95.04	Long-Term	76.4	87.0	91.1	98.2				3.16
Orleans TS	117.27	Near-Term	110.0	122.3	133.0	137.8		5.03	15.73	20.53
Cyrville MTS	45	Medium-Term	28.1	45.5	50.9	57.7		0.5	5.9	12.7
Moulton MTS	29.7	Near-Term	29.8	35.3	34.8	34.5	0.1	5.6	5.1	4.8
Cumberland DS	6.75	Long-Term	5.7	6.0	6.6	7.0				0.25
Hawthorne TS	136.8	Near-Term	123.5	139.1	156.8	172.5		2.3	20	35.7

The forecast for some of the above stations shows a very small level of overloading, well within the forecast uncertainty of the station, even in the near term. With the exception of

Manotick DS, Marionville DS, and Hawthorne TS the above stations are owned by Hydro Ottawa. Hydro Ottawa's distribution network has significant capability to transfer load between its stations. This enables the timely restoration of lost load in excess of an individual station's limited time rating if a station transformer were to experience an outage during a period when the station was heavily loaded. As a result, in many cases is reasonable for the planning forecast to exceed the station LTR without introducing significant reliability risk.

Based on this forecast there is a need to monitor demand trends at these stations over the next few years, however it would be premature to plan for additional station capacity for each of these stations during this IRRP. All of the stations identified above, with the exception of Hawthorne TS, are supplied by the regional 115 kV transmission system. Ongoing planning work following the release of this IRRP will consider the potential for non-wires alternatives to reduce demand at these stations, in order to reduce the flow through the 230/115 kV transformers.

Voltage Regulation at Terry Fox MTS

Terry Fox MTS is a dual element spot network (DESN) type station, a design which is typically supplied by two circuits, however the initial configuration of Terry Fox consists of two transformers, both connecting onto 230 kV circuit E34M/T33E, the only 230 kV supply in the vicinity. Circuit E34M/T33E is a 290 km circuit connecting Merivale TS in Ottawa to Clarington TS in the east Greater Toronto Area. Almonte TS, which for the purpose of regional planning is usually considered to be part of the Outer Ottawa Sub-Region, is located West of Terry Fox MTS, and is also solely supplied by this circuit.

The 2018 Needs Assessment identified that if the circuit were open at the Merivale TS end (a line end open, or LEO contingency), the long circuit from Clarington TS would not provide adequate support for Almonte TS and Terry Fox MTS during the peak loading period, resulting in voltages below the minimum level allowed by the ORTAC.[3] As noted above, Hydro Ottawa

[3] The System Impact Assessment (SIA) report that the IESO completed in June 2019 for the South Nepean MTS also examined this issue, since the new station will be supplied by this circuit under normal circumstances. The South Nepean TS connection includes an automatic fast load transfer scheme that will transfer the station to the alternate 115 kV supply circuit (S7M) if circuit E34M/T33E is open at the Merivale TS end, therefore the new South Nepean TS will not impact this issue.

is planning distribution system upgrades and transfers that may load Terry Fox TS above the station planning capacity over the next few years. Investigation during the IRRP, however, found that existing Hydro One E34M line protection schemes and settings at Merivale TS and Almonte TS isolate E34M between Almonte TS and Merivale TS when the LEO at Merivale TS contingency is detected.

C.8.2 Restoration of Post-Contingency Peak Load Loss

Table C-4: Load Loss and Restoration for Contingencies Affecting More Than 250 MW of Load

		Load Lost by Configuration and Rejection/Curtailment [MW]				Load Restoration Requirement in 2025 [MW]			Recommended Actions
Affected Stations	Contingency	2020	2025	2030	2037	30-min Restoration Requirement	4-hour Restoration Requirement	8-hour Restoration Requirement	
Kanata MTS, South March TS, and Nepean TS	Fault on M32S/C3S Followed by South March TS A1A2 Breaker Failure	306.5	317.5	312.9	315.8	67.5	167.5	317.5	Hydro One has confirmed that the affected load can be restored within the applicable timeframes.

		Load Lost by Configuration and Rejection/Curtailment [MW]				Load Restoration Requirement in 2025 [MW]			Recommended Actions
Affected Stations	Contingency	2020	2025	2030	2037	30-min Restoration Requirement	4-hour Restoration Requirement	8-hour Restoration Requirement	
Marchwood MTS, Bridlewood MTS, Fallowfield DS Richmond DS, and Manotick DS	Fault on S7M/W6CS Followed by South March SS L6L7 Breaker Failure	154.2	157.1	168.1	169.3	0	7.1	157.1	Hydro One has confirmed that the affected load can be restored within the applicable timeframes.

		Load Lost by Configuration and Rejection/Curtailment [MW]				Load Restoration Requirement in 2025 [MW]			Recommended Actions
Affected Stations	**Contingency**	**2020**	**2025**	**2030**	**2037**	**30-min Restoration Requirement**	**4-hour Restoration Requirement**	**8-hour Restoration Requirement**	
Nepean Epworth TS, Carling TS, and Lisgar TS	M4G and M5G	180.9	189.6	194.2	197.6	0	39.6	189.6	Hydro One has confirmed that the affected load can be restored within the applicable timeframes.
Orleans TS, Navan DS, Wilhaven DS, Cumberland DS, and all stations on circuit 79M1	H9A and D5A	166.8	182.9	193.9	205.5	0	32.9	182.9	Hydro One has confirmed that the affected load can be restored within the applicable timeframes.

C.8.3 Supply to the Regional 115 kV Transmission System

Table C-5: Flow Through Most Limiting 230/115 kV Transformers at Merivale TS and Hawthorne TS

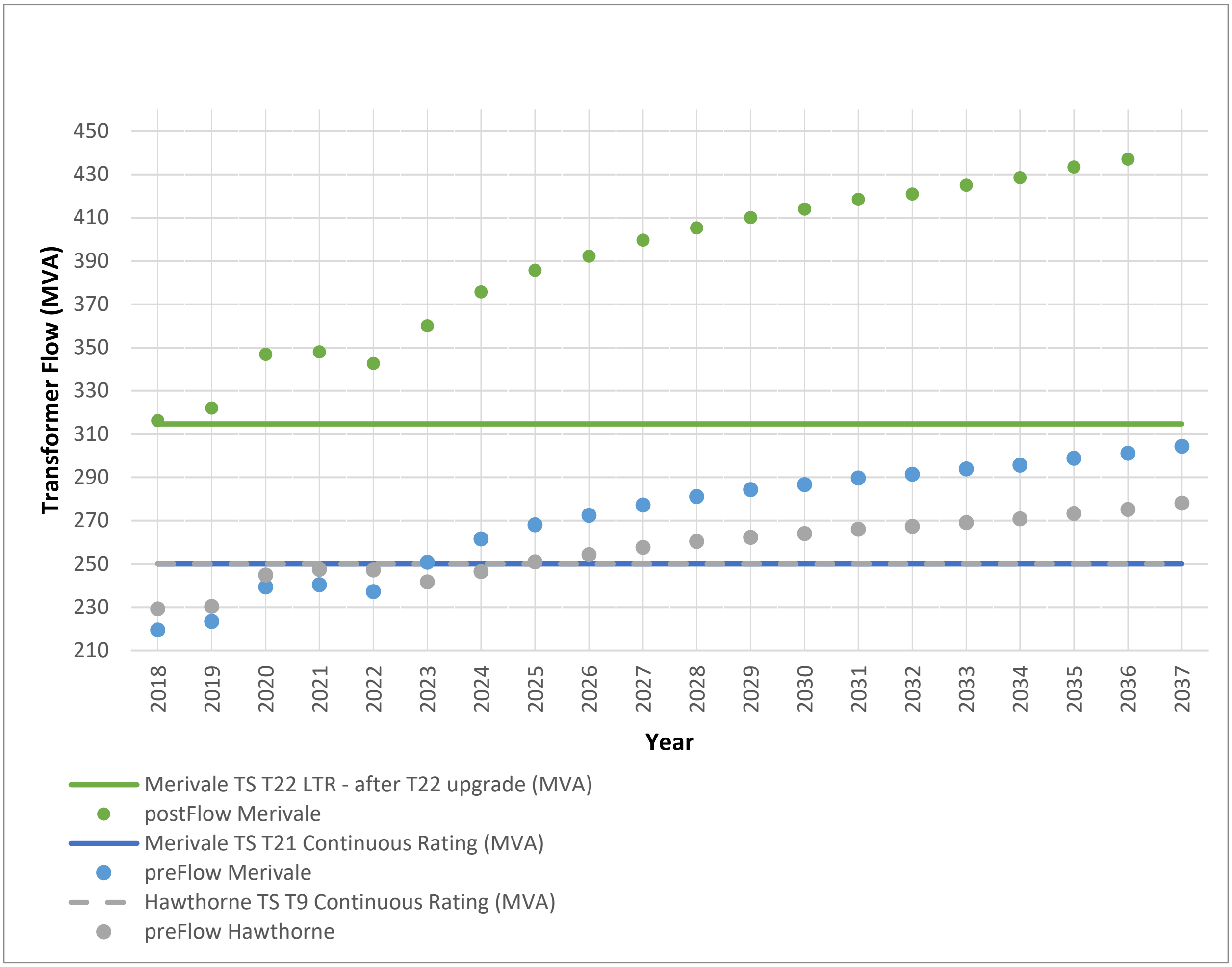


Table C-6: Thermal Need Dates for Most Limiting 230/115 kV Transformers at Merivale TS and Hawthorne TS

Transformer	Need Date
Merivale TS T22 Post-Contingency (loss of T21)	2018
Merivale TS T21 Pre-Contingency	2023*
Hawthorne TS T9 Pre-Contingency	2025*

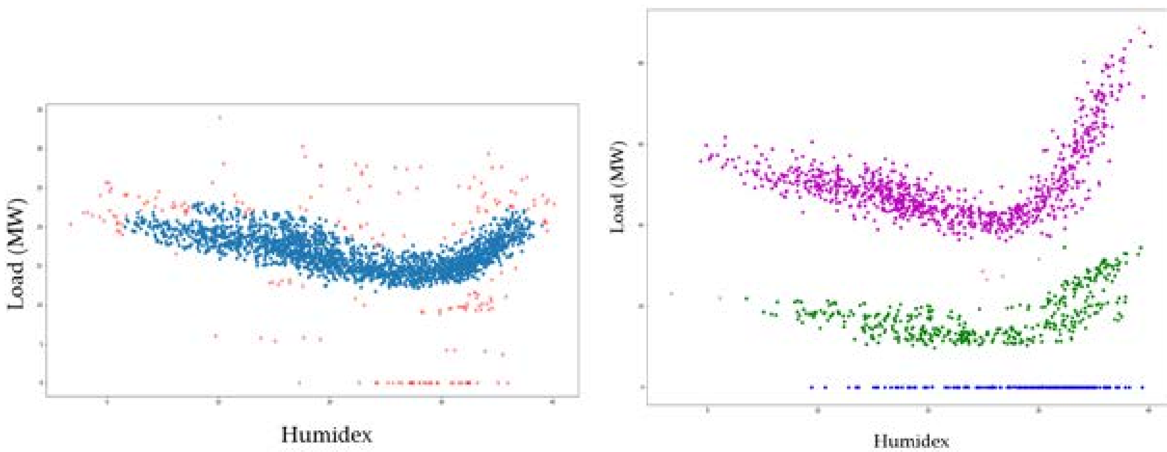
*Preliminary. Results are subject to sensitivity analysis and other impacts that require ongoing study.

Appendix D: Evaluation of Non-Wires Options

D.1 HOURLY LOAD FORECASTING

Hourly load forecasting was conducted on a station-level, using multiple linear regression with at least approximately four years' worth of historical hourly load data. To begin, a density-based clustering algorithm was used for filtering the historical data for outliers (including fluctuations possibly caused by load transfers, outages, or infrastructure changes). As depicted in Figure D-1, the clustering algorithm helped identify historical load trends when assessing the load vs. humidex[4] relationship.

Figure D-1: Sample Results of Clustered Historical Data for Uplands TS (left) and Orleans TS (right)



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

- Calendar factors (such as holidays and days of the week)
- Weather factors (including temperature, dew point, wind speed, cloud cover, and fraction of dark; both weekday and weekend heating, cooling, and dead band splines were modelled)
- Demographic factors (population data[5])
- Economic factors (employment data[6])

[4] For the Ottawa Sub-Region, defined as a function of temperature and dew point.
[5] Sourced from the Ministry of Finance and Statistics Canada
[6] Sourced from the Centre for Spatial Economics, IHS Markit Ltd., and the Conference Board of Canada

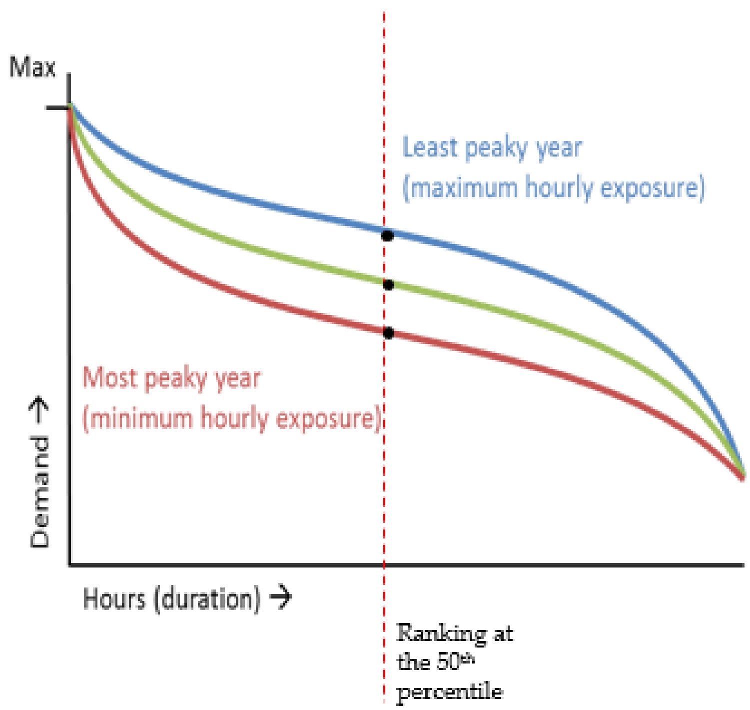
Model diagnostics (training mean absolute error, testing mean absolute error) were used to gauge the effectiveness of the selected predictor variables and to avoid an overfitted model.

After fitting the model to historical data, future hourly load was forecast by inputting projected values for all predictor variables. While future values for calendar, demographic, and economic variables were incorporated straightforwardly, predicting the impact of future weather on an hourly basis required a more complex approach. 31 years' worth of historical weather data (which is a blend of all the weather-related variables listed above) were obtained. Additionally, to fully assess the impact of different weather sequences against the other non-weather variables, the historical weather for each of the 31 previous years was shifted both ahead and behind up to seven days, resulting in 15 total variations. This approach ultimately led to 465 possible hourly load forecasts for *each* year being forecast:

$$31\ years\ of\ historical\ weather\ data \times 15\ weather\ sequence\ shifts$$
$$= 465\ weather\ scenarios\ for\ each\ year\ being\ forecast$$

To compare each weather scenario and the resultant hourly load forecasts, load duration curves were created for each scenario and ranked (illustratively shown in Figure D-2).

Figure D-2: Example of Ranking Load Duration Curves Created from Hourly Load Profiles



For the purposes of the Ottawa Sub-Region, the hourly forecast corresponding to the load duration curve with less energy (i.e., 97th percentile, nearing the red curve shown illustratively above in Figure D-2) was selected for scaling. The chosen load profiles were then uniformly scaled across all hours to ensure that the modelled peak demand aligned with the planning peak forecasts (defined in Appendix B.7) for each station being studied.

D.2 NEED CHARACTERIZATION USING HEAT MAPS

The hourly load forecasts were assessed against station load meeting capabilities to provide a more probabilistic definition of capacity needs. The following heat maps help visualize the magnitude (MW), duration (hours), and frequency of needs that may occur in a load pocket or at a specific station given the hour of the day and year.

Figure D-3: Heat Map for Kanata-Stittsville Area (Terry Fox MTS, Marchwood MTS, Kanata MTS) Needs in 2020

MW \ 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
18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	2%	2%	2%	2%	1%	1%	0%	0%
6	0%	0%	0%	0%	0%	1%	2%	2%	3%	3%	3%	3%	3%	3%	3%	4%	4%	4%	4%	4%	4%	3%	2%	1%
0	4%	3%	3%	3%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%

Figure D-4: Heat Map for Leitrim MS Needs in 2020

MW \ 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
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Figure D-5: Heat Map for Leitrim MS Needs in 2037

MW \ 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
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	2%	2%	3%	3%	2%	2%	1%	1%	1%	0%	0%
12	1%	1%	1%	1%	1%	3%	3%	3%	3%	3%	3%	3%	3%	3%	4%	4%	4%	3%	3%	3%	2%	2%	2%	1%
8	3%	3%	3%	3%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	3%	3%
4	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
0	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%

A sample interpretation of these heat maps is as follows: of all hours during which a need is predicted in the Kanata-Stittsville area in 2020, ~1% is expected to occur at 6 AM *and* with at least 6 MW in magnitude. On the other hand, the heat map for Leitrim MS in 2020 suggests that no need events are anticipated.

D.3 POTENTIAL FOR ENERGY EFFICIENCY

The IESO and the Ontario Energy Board have recently completed the first integrated electricity and natural gas achievable potential study in Ontario (2019 APS). The main objective of the APS is to identify and quantify energy savings (electricity and natural gas), GHG emission reductions and associated costs from demand side resources for the period from 2019-2038. The study is used to inform future energy efficiency policy and/or frameworks, program delivery as well as long-term resource planning.

The 2019 APS determined that both fuels have significant cost-effective energy efficiency potential in the near and longer term. Depending on the type and level of customer incentives provided, summer peak demand savings potential ranges from 500 to 800 MW in 2023 and from 2,000 to 3,000 MW in 2038.[7] Potential energy savings range from 4.8 to 6.9 TWh in 2023 and from 18 to 24 TWh in 2038.

Modeling undertaken for this study also produced considerable data that can be used to understand energy efficiency opportunities at a more local level. Specifically, the 2019 APS results are broken out by:

- IESO transmission zone - see map available on the IESO's website here
- Customer segment - e.g., single family dwellings, multi-unit residential buildings, large commercial office, restaurant, school, warehouse, etc.
- End use – e.g., lighting, space heating, space cooling, plug load, etc.
- Measure – e.g., high bay LED lighting, air source heat pumps, building recommissioning

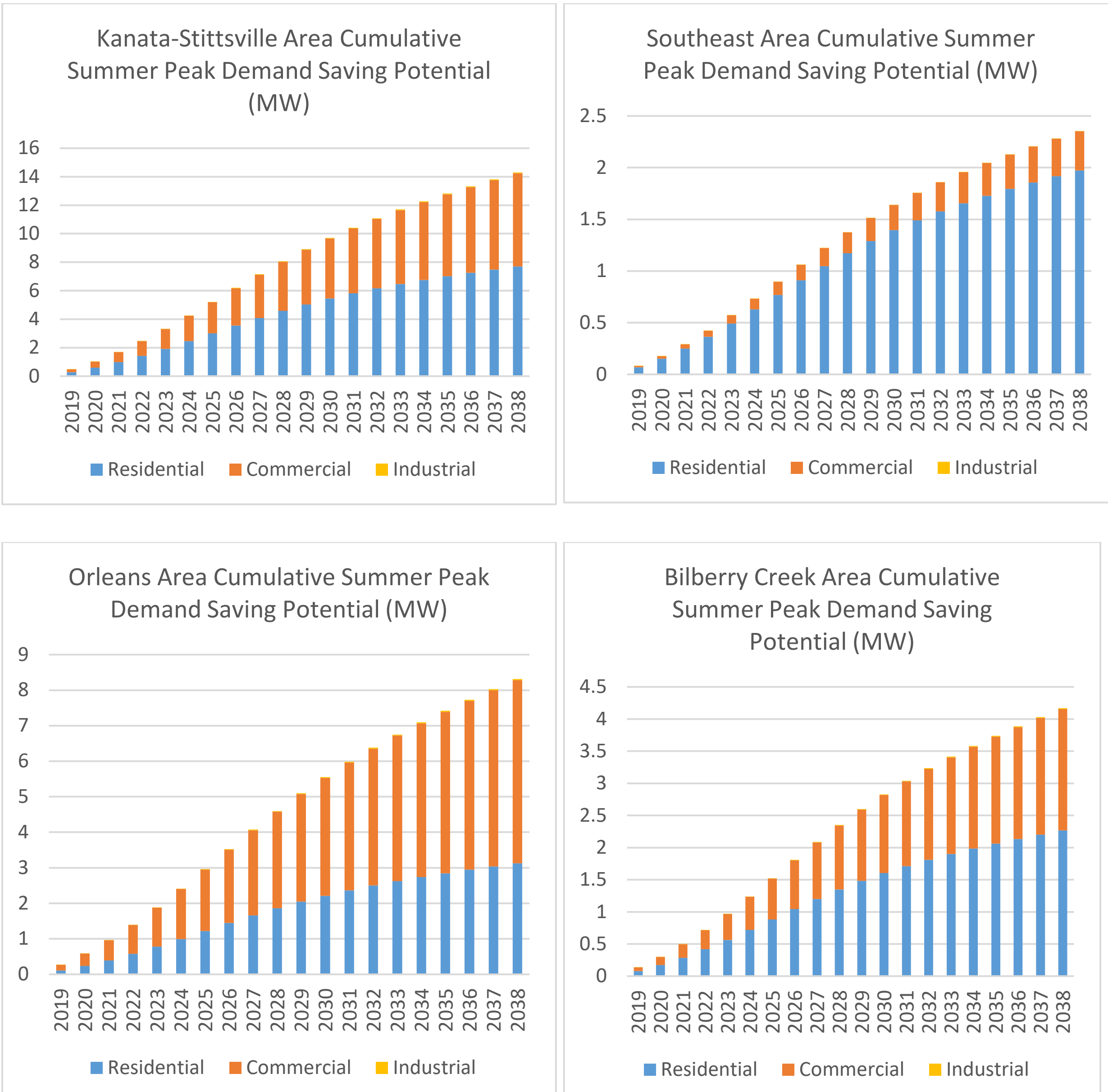
Using local data about composition of businesses, housing and industry these results can be translated into energy and summer peak demand savings potential estimates for the Ottawa IRRP study area. Local data sources used for this analysis include Municipal Properties Assessment Corporation building data, the Broader Public Sector energy use data, and Dunn and Bradstreet employee counts.

Based on this analysis, energy efficiency opportunities are expected to be available in throughout this IRRP study area. Potential is predominantly concentrated in the residential and

[7] All annual savings potentials reported in the study are based on the cumulative adoption of measures over time (e.g., savings in 2023 represent the potential savings in 2023 of measures adopted in 2019 through 2023).

commercial sectors given the composition of customers. Figure D-6 shows the total estimated potential for energy efficiency to reduce summer peak demand in the Ottawa Sub-Region.

Figure D-6: Cumulative System Cost-Effective Energy Efficiency Potential to Reduce Peak Summer Demand



Tables D-1 and D-2 below, summarize the summer peak demand savings opportunities and associated costs by sector in the West and South-East sub-regions of the study area. Here the West sub-region covers customers served by Terry Fox, Marchwood and Kanata MTSs and South East includes Leitrim, Uplands and Limebank MTSs.

This table and the analysis included in Section 7 of the report capture all energy efficiency potential that is cost effective from the provincial system perspective derived by scaling the maximum achievable potential scenario results from the 2019 APS for the Ottawa transmission zones down to the regional level. Energy efficiency measures that are cost effective from the system perspective are measures that have a total resource cost test ratio greater than one – i.e., they produce benefits from avoided energy and system capacity costs that are greater than the costs of the measures that are incremental to the cost of the baseline measures (e.g., the extra cost to install a smart thermostat over a standard thermostat).

Achievable potential in the APS also considers both technical considerations affecting energy efficiency potential, such as the number of customers with low-efficiency equipment or operations that can technically be upgraded as well as market considerations such customer responses to payback periods under different incentive rates. The energy efficiency potential estimates resulting from this analyses provide insight into the magnitude of energy efficiency savings that would be beneficial to the provincial electricity grid and can likely be achieved given customer behavior.

Table D-2: Summer Peak Demand Savings Potential

Annual Maximum Incremental Cost Effective Achievable Potential (kW)																			
Sub-Region	**Sector**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
West	Residential	266	302	338	361	370	369	344	337	299	266	274	256	210	179	188	182	172	162
	Commercial	369	325	353	362	379	324	332	310	285	240	191	148	135	56	25	1	-	-
	Industrial	3	3	4	4	4	4	4	4	3	3	3	2	2	1	0	-	-	-
	Total	638	630	694	727	753	697	680	651	587	510	467	406	347	235	214	182	172	162
South-East	Residential	213	242	270	289	296	295	275	270	239	213	219	204	168	143	150	145	137	130
	Commercial	183	163	175	180	185	153	159	147	134	112	89	68	61	21	6	-	-	-
	Industrial	46	49	53	62	65	64	63	60	53	47	40	34	28	10	3	-	-	-
	Total	442	454	499	530	546	513	498	477	426	372	348	306	257	175	160	145	137	130

Table D-2: Costs to Achieve Summer Peak Demand Savings

Annual Cost for Maximum Cost Effective Achievable Potential ($Million CAD)																			
Sub-Region	**Sector**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
West	Residential	$0.9	$1.0	$1.1	$1.2	$1.3	$1.4	$1.5	$1.5	$1.6	$1.6	$2.0	$2.0	$2.0	$2.1	$2.1	$2.1	$2.1	$2.2
	Commercial	$1.1	$1.1	$1.3	$1.4	$1.5	$1.5	$1.5	$1.4	$1.3	$1.2	$1.1	$0.9	$0.9	$0.8	$0.7	$0.7	$0.7	$0.7
	Industrial	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	Total	$1.9	$2.1	$2.4	$2.6	$2.9	$2.9	$3.0	$2.9	$2.9	$2.8	$3.0	$3.0	$2.9	$2.9	$2.8	$2.8	$2.8	$2.9
South-East	Residential	$0.7	$0.8	$0.9	$1.0	$1.1	$1.1	$1.2	$1.2	$1.3	$1.3	$1.6	$1.6	$1.6	$1.7	$1.7	$1.7	$1.7	$1.8
	Commercial	$0.5	$0.6	$0.6	$0.7	$0.8	$0.7	$0.7	$0.7	$0.6	$0.6	$0.5	$0.4	$0.4	$0.4	$0.3	$0.3	$0.3	$0.3
	Industrial	$0.1	$0.1	$0.1	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
	Total	$1.3	$1.4	$1.6	$1.8	$2.0	$2.1	$2.1	$2.1	$2.1	$2.0	$2.2	$2.2	$2.2	$2.2	$2.1	$2.1	$2.1	$2.1

D.4 ECONOMIC ASSESSMENT OF OPTIONS

New transmission facilities, generation, and integrated solutions of demand response, energy efficiency, distributed energy resources, and/or energy storage were studied to alleviate needs identified in this IRRP. After developing a portfolio of feasible options to meet the different needs, each of the viable options are evaluated according to their consumer impact. An economic analysis of all options (including combination of resources) was conducted and their relative net present values (NPV) were compared.

The following is a list of the assumptions made in the economic evaluation for the different sub-regions in the Ottawa Sub-Region IRRP:

- The NPV of the cash flows is expressed in 2019 $CAD.
- The NPV analysis was conducted using a 4% real social discount rate. An annual inflation rate of 2% is assumed.
- The life of the station upgrades was assumed to be 45 years; the life of the storage option was assumed to be 10 years; and the life of the generation assets was assumed to be 30 years.
- The new transmission station costs in Southeast Ottawa and Kanata-Stittsville were both assumed to be $28 million (2019 $CAD) each, plus $5 million (2019 $CAD) in 230 kV transmission connection costs
- Natural gas prices were assumed to be an average of $4/MMBtu throughout the study period
- The USD/CAD exchange rate was assumed to be 0.78 for the study period

For many needs in the Ottawa area, only a natural gas-fired facility or energy storage was determined to be technically capable of meeting the full magnitude and timing required. A natural gas-fired simple cycle gas turbine (SCGT) was determined to be the lowest-cost resource alternative to transmission reinforcements. Its estimated overnight cost of capital assumed is about $1,445/kW (2019 $CAD), based on escalating values from a previous study independently conducted for the IESO.