York Region:

Integrated Regional Resource Plan

- Appendices

February 28, 2020

Connecting Today.
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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. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

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

In the fall of 2012, the Ontario Energy Board ("OEB") convened a Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of electricity agencies, utilities, and other stakeholders. In May 2013, the PPWG released its report to the OEB[1] ("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.

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

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 least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a two-week public comment period prior to finalization.

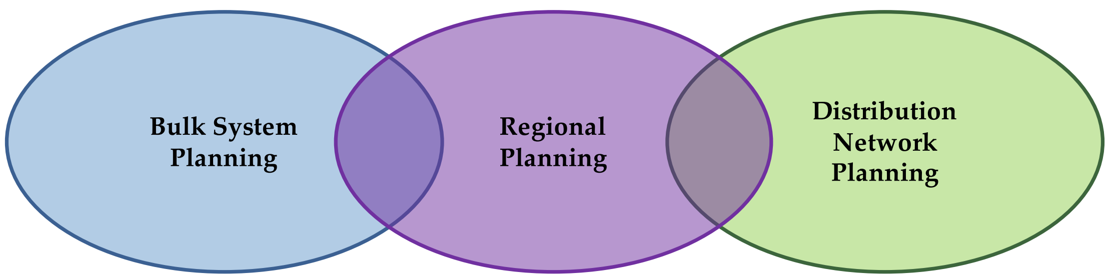
The final Needs Assessment Reports, Scoping Assessment Outcome Reports, IRRPs and RIPs are posted on the IESO's and the relevant transmitter's websites, and may be referenced and submitted to the OEB as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis community councils for planning, and for conservation and energy management purposes. They are also a useful source of information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning undertaken in Ontario. As shown in **Error! Reference source not found.**, 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 local distribution companies ("LDCs"), considers specific investments in an LDC's territory at distribution-level voltages.

Regional planning can overlap with bulk system planning and with the distribution planning of LDCs. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue or when a distribution solution addresses the needs of the broader local area or region. As a result, it is important for regional planning to be coordinated with both bulk and distribution system planning, as it is the link between all levels of planning.

Figure 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

By recognizing the linkages with bulk and distribution system planning, and coordinating the multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan into perspective. Furthermore, in avoiding piecemeal planning and asset duplication, regional planning optimizes ratepayer interests, allowing them to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

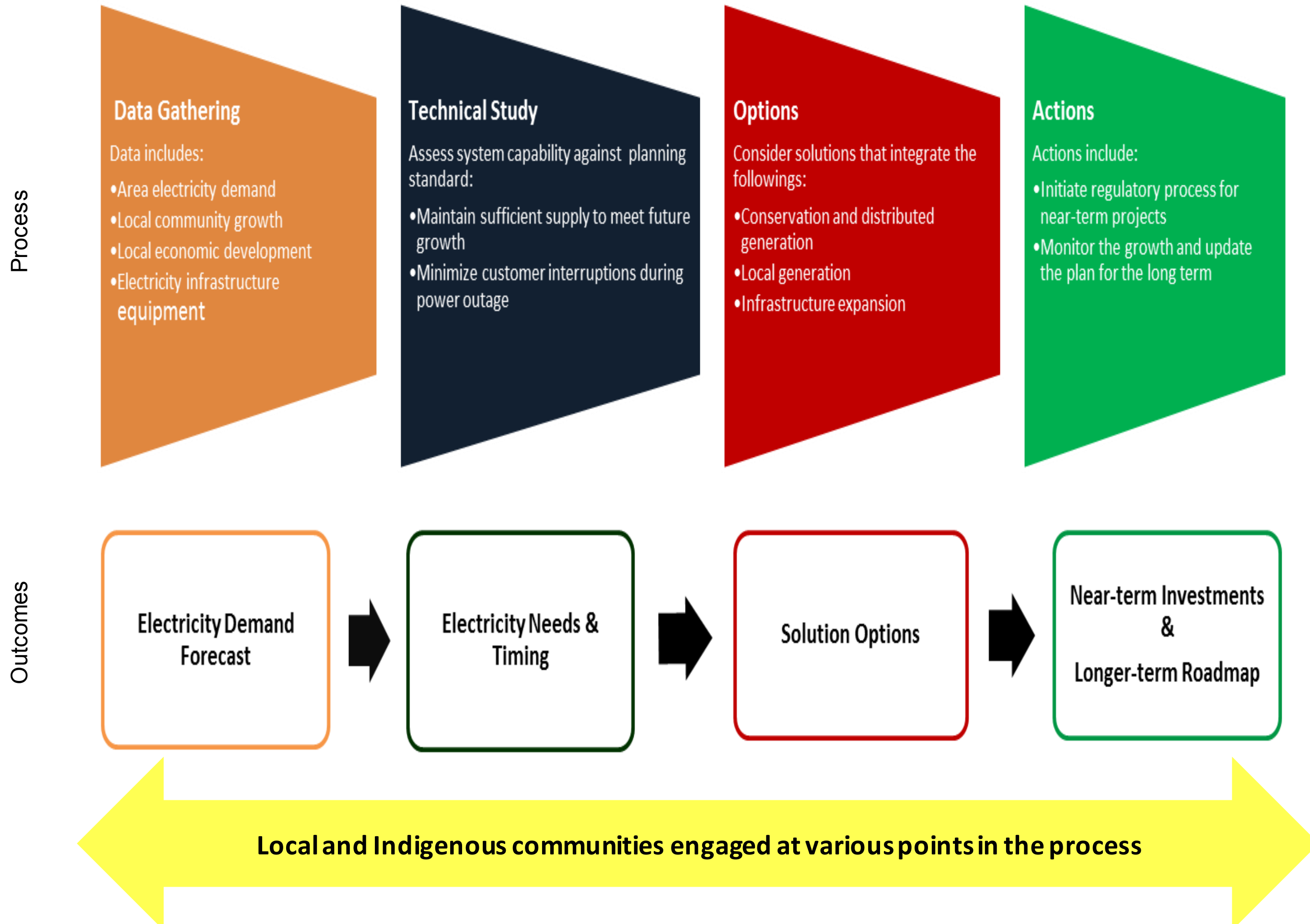
A.2 The IESO’s Approach to Regional Planning

IRRPs assess electricity system needs for a region over a 20-year period, enabling 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 any changes in the existing provincial conservation 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 follow a process, with a clearly defined series of steps (see Figure A-2). These includes 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 who may have 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 plan 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 conservation, 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 Forecast

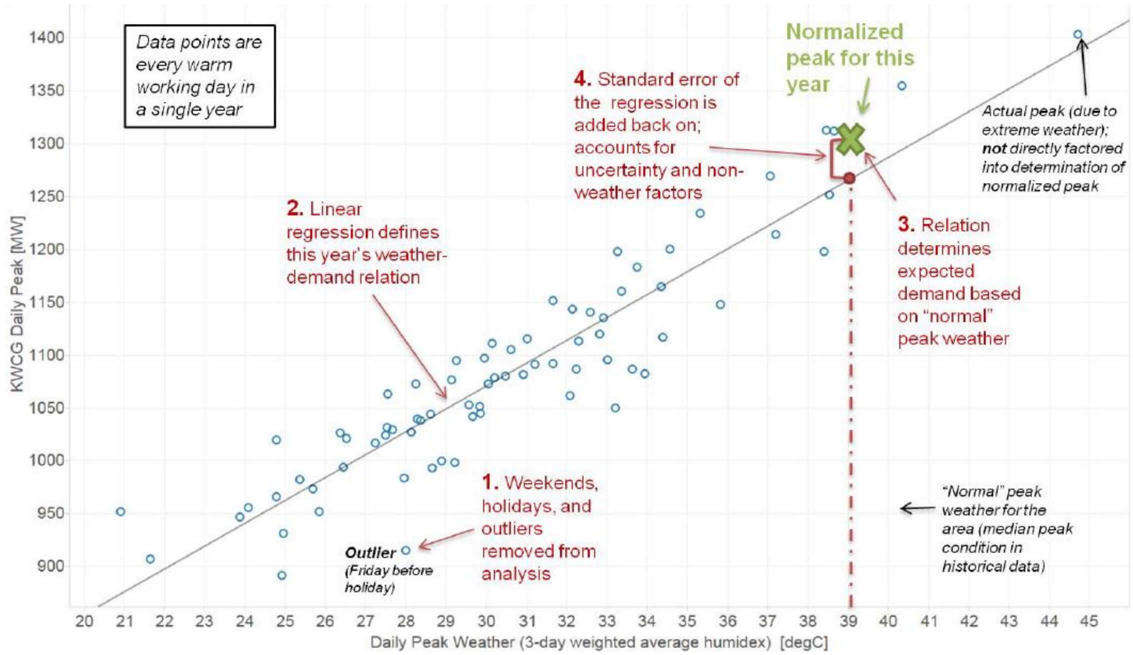
This Appendix describes the methodologies used to develop the demand forecast (peak and duration) for the York Region IRRP studies. Forward-looking estimates of electricity demand were provided by each of the participant LDCs, using a starting point (representing the present-day peak load) and base year for the demand forecast to use as a reference. The sections that follow describe the method used by the IESO to determine the forecast starting point, the forecast approaches describing the methods used by each LDC to forecast demand in their respective service area, and the energy efficiency assumptions used to modify the demand based on expected energy efficiency savings.

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 2017). Median peak refers to what peak demand would be expected if the most likely, or 50th percentile, weather conditions were observed. This means that in any given year there is an estimated 50% chance of exceeding this peak, and a 50% chance of not meeting this peak. The methodological steps are described in Figure B-1.

Figure B-1: Method for determining the weather-normalized peak



The median weather peak for 2017 was provided, on a station and LDC load basis, to each LDC. This data was used as a start point from which to develop 20 year demand forecasts, using the LDCs preferred methodology (described in Appendix B.2, below).

Once there 20 year, 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. 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. The extreme weather adjustment factors used in the York IRRP were submitted by LDCs based on their knowledge and experience with modelling their customers demand responses during extreme conditions. These were: 6.6% above the normal weather in Alectra Utilities service territory; and, 6% above the normal weather for Newmarket-Tay Power and Hydro One Distribution.

B.2 LDC Forecast Methodologies

As described in the IRRP, LDCs were provided with a starting point for their forecasts, based on weather normalized peak demand. This section includes the forecast methodologies provided by the participant LDCs.

B.2.1 Alectra Utilities Inc.

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

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

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

End-Use Analysis Using the Latest Information

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

Population Growth: Historical annual population growth was obtained from Regional Annual Economic and Municipal Development Review Reports. Long-term annual population projections were obtained from provincial and municipal official plan reports published by the Ontario government, and regional/municipal governments.

Employment Growth: Historical employment and economic growth statistics reports published by Provincial and Municipal governments were used to extract the historic economic development and growth rates. Employment growth and structure projections were used to develop the long-term employment forecast categorized by the sector, industry and service types.

Housing Activities: The number and mix of housing completions, vacancy rates and building permit activities in the Region/Municipal boundaries, and residential developments plan were reviewed. Plans of subdivisions and condominiums were obtained and analyzed to develop the long-term load forecast.

ICI Building Activity: Industrial and Commercial development rate, commercial vacancy rate, industrial sale prices per square feet, total ICI construction and commercial/industrial building permits were obtained and compiled to develop the long-term load forecast.

Weather Correction

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

Other Factors

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

<u>CDM</u>

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

<u>DG</u>

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

<u>Electrification of Transportation</u>

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

Past System Peak Performance and Trend Analysis

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

Conclusion

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

B.2.2 Hydro One Networks Inc. (Distribution)

Hydro One Distribution services the areas of York Region that are not serviced by other LDCs. It supplies power via four step-down transformer stations from 230 kV to 44 kV to an area that includes the Chippewas of Georgina Island First Nation. The four stations are Armitage TS, Holland TS, Brown Hill TS, and Kleinburg TS.

- Hydro One Distribution used both econometric and end-use forecasting to develop the 20-year load forecast provided to the IESO.
- A baseline forecast (MW station peak in the base year) was developed, taking into account such factors as normal operating conditions, coincident peak loading, and extreme weather conditions.
- For the York Region IRRP forecast, Hydro One Distribution used the weather corrected peak demand levels for Kleinburg TS, Holland TS, Armitage TS and Brown Hill TS.
- From the established baseline year, a growth rate (%) was applied to station demand levels to provide forecast values, at each station, within the study timeframe.
- Assumptions included in the growth rate can be related to such factors as: Ontario GDP growth rate, housing statistics, the intensification of urban developments (i.e., MW/sq.ft); and the need for large scale electrification projects.
- Where possible, detailed information about load growth, based on local knowledge and or municipal/provincial plans, was used to augment the forecast values within the study period.

B.2.3 Newmarket-Tay Power Distribution Ltd.

Newmarket-Tay Power Distribution Ltd. ("NT Power") owns and operates the electricity distribution system within its OEB licenced service area, which is the Town of Newmarket including small areas bordering the municipalities of King and East Gwillimbury, in the Regional Municipality of York (Newmarket Service Area), as well as the Simcoe County communities of Port McNicoll, Victoria Harbour and Waubaushene, which are part of the Township of Tay (Tay Service Area) and the Town of Midland (Midland Service Area). For the purpose of this study, the focus was only on the Newmarket Service Area. NT Power serves approximately 32,000 Residential and General Service customers within the Newmarket Service Area.

Community in Transition

Currently home to approximately 94,000 residents, the Town of Newmarket's population growth rate has surpassed those of Ontario and Canada in recent years, and the Town's population is projected to continue to grow steadily in the years to come. From 2006 to 2011, Newmarket saw its population increase by 7.6%, compared to the national average growth of 5.9% and the provincial growth rate of 5.7%. Newmarket experienced significant growth in the early 2000s as well – the Town's population increased by 12.9% from 2001 to 2006, compared to Ontario's increase of 6.6%. The Town will continue to grow and is expected to have a population close to 118,000 by 2041. Due to the fact that Newmarket has reached its urban boundary, the majority of this population growth will be accommodated by intensification as new development and redevelopment will become increasingly vertical.

A strategic area within the Town of Newmarket has been designated by the Province of Ontario as an Urban Growth Centre in the Growth Plan for the Greater Golden Horseshoe, which promotes higher density development, a lower rate of vacant land utilization, build out in urban areas, and increased public transit use.

Forecast Municipal Growth Rate Basis of Load Forecast

In developing the forecast, NT Power relied upon a combination of past historical growth, as well as ongoing discussions with planning staff of both the Town of Newmarket and the Region of York. The Region of York's approved official plan with forecast projected growth was the basis of this load forecast with further analysis associated with the Town of Newmarket's Secondary Plan and Community Energy Plan. For the current load forecast, the coincident peak data from 2018 was used as the base for the load forecast. In developing the load forecast, several factors had to be considered and evaluated to determine potential growth within the service area. The electric load forecast was one of the key drivers of NT Power's planning activities at both the distribution planning level and overall supply requirements from the bulk wholesale transmission system.

Base Forecast: Trend and End Use Analysis

Trend Analysis used historical consumption of electricity demand to predict future requirements. A combination of timeframes (5, 10, 15 years) was used to determine potential demand increases as compared to forecast growth. Regular updating and review will be completed on an annual basis.

A second analysis was completed based on customer end use. End use analysis can identify new or significant increases/decreases in electrical demand, as well as locational information, that may not be captured through trend analysis.

As stated above, the Town of Newmarket is a community in transition with the primary focus for future growth centered on the Yonge St. and Davis Dr. corridors. The Town of Newmarket expects to achieve population and employment growth targets through increased density and vertical development. This anticipated significant increase in land-use intensification, as well as the complete renewal of the commercial sector, will provide the biggest impact on load growth over the forecast period.

Load growth is also expected in the area of transportation electrification ranging from increased market penetration of consumer electric cars to the conversion of existing commercial fleets in the Newmarket service area (i.e. York Region Transit converting from diesel buses to battery buses over a defined period of time). End-use analysis would identify increases in large spot transportation electrification loads (i.e. YRT bus depot) over the forecast period.

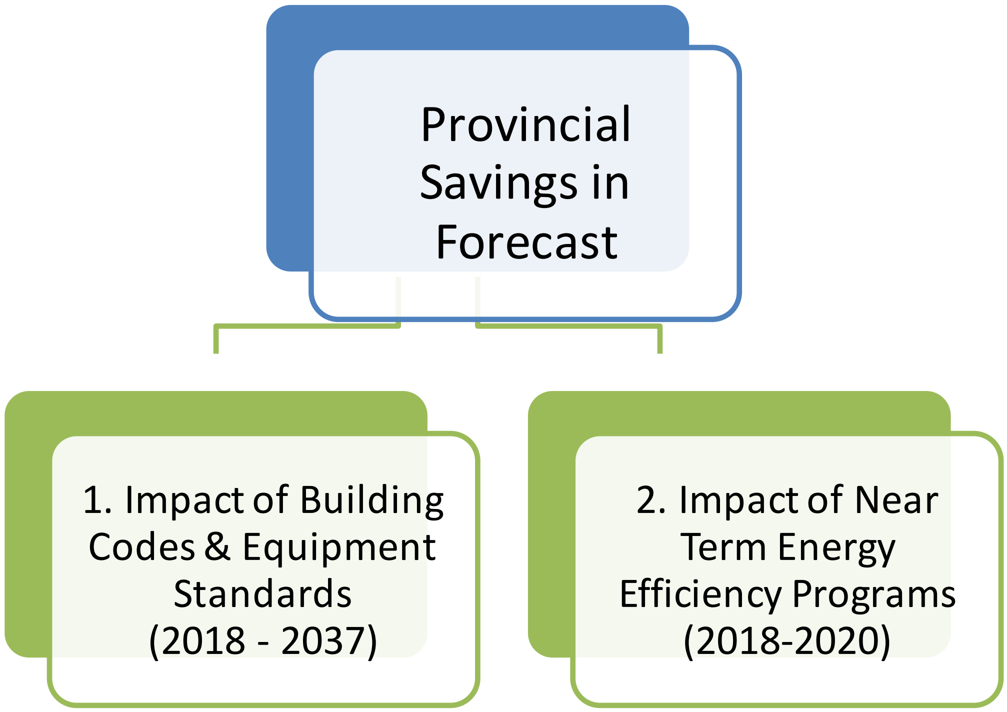
The end-use analysis methodology considered that the demand for electricity is dependent on what it is used for. An analysis was completed on end-use usage and demand was subsequently allocated between residential and industrial/commercial/institutional ("ICI") type demand. Using standard historical usage data per end-use customer (i.e. single-family dwelling demand vs apartment complex demand; warehouse demand vs data center demand) provided a basis to forecast expected demand with load growth across both residential and industrial ICI demand.

B.3 Existing or Committed Energy Efficiency Assumptions in York Forecast

As shown in Figure B-2, 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 were allocated according to the forecast residential, commercial, and industrial gross demand.

This appendix provides additional breakdowns of estimated energy efficiency savings for the York Region and more detail on how the savings for the two categories were developed.

Figure B-2: Existing or Committed Energy Efficiency Savings Categories

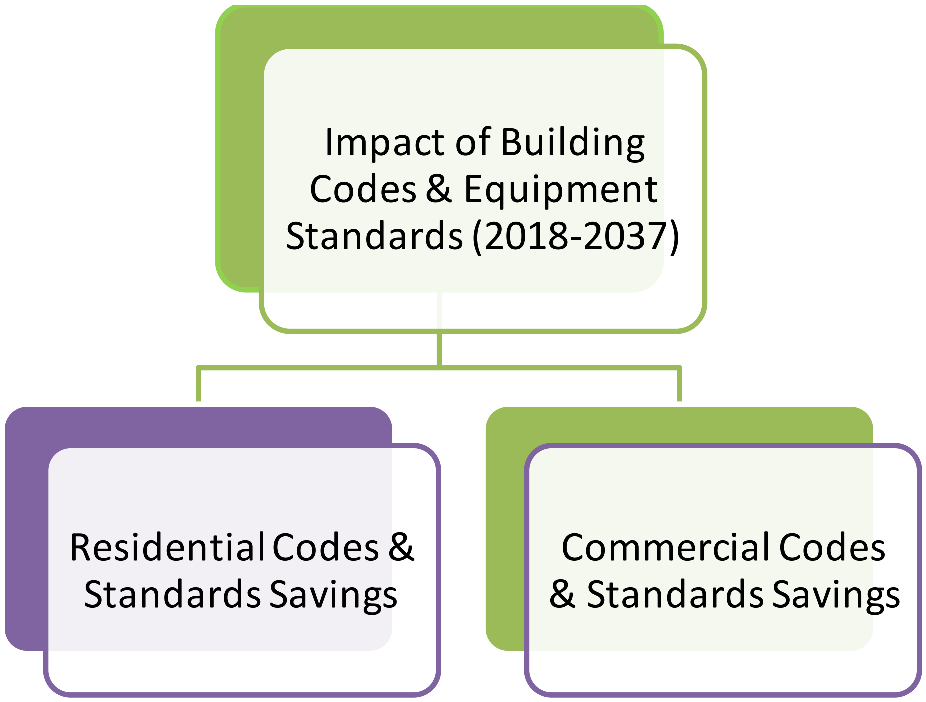


1. *Savings due to building codes and equipment standards*
2. *Savings due to the delivery of energy efficiency programs*

B.3.1 Estimating Savings from Building Codes and Equipment Standards

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

Figure B-3: Split of Building Codes & Equipment Standards Savings



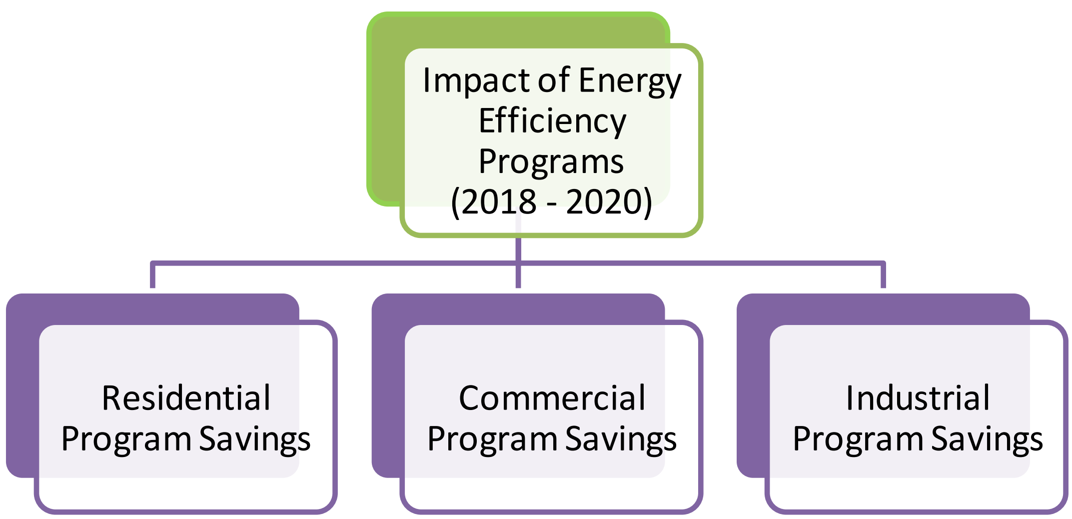
**Savings are projected for residential and commercial sectors only*

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 6.3 per cent peak-demand savings through standards, while the commercial sector will see about 5.0 per cent peak-demand savings through codes.

B.3.2 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 were included in the regional planning forecast. This differs from the evaluation of future Energy Efficiency Potential, which is presented in Appendix C: . 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 used 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 included detailed savings projections from energy efficiency and funded behind-the-meter generation projects, and indicated 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-4: Time Frames for Energy Efficiency Program Savings



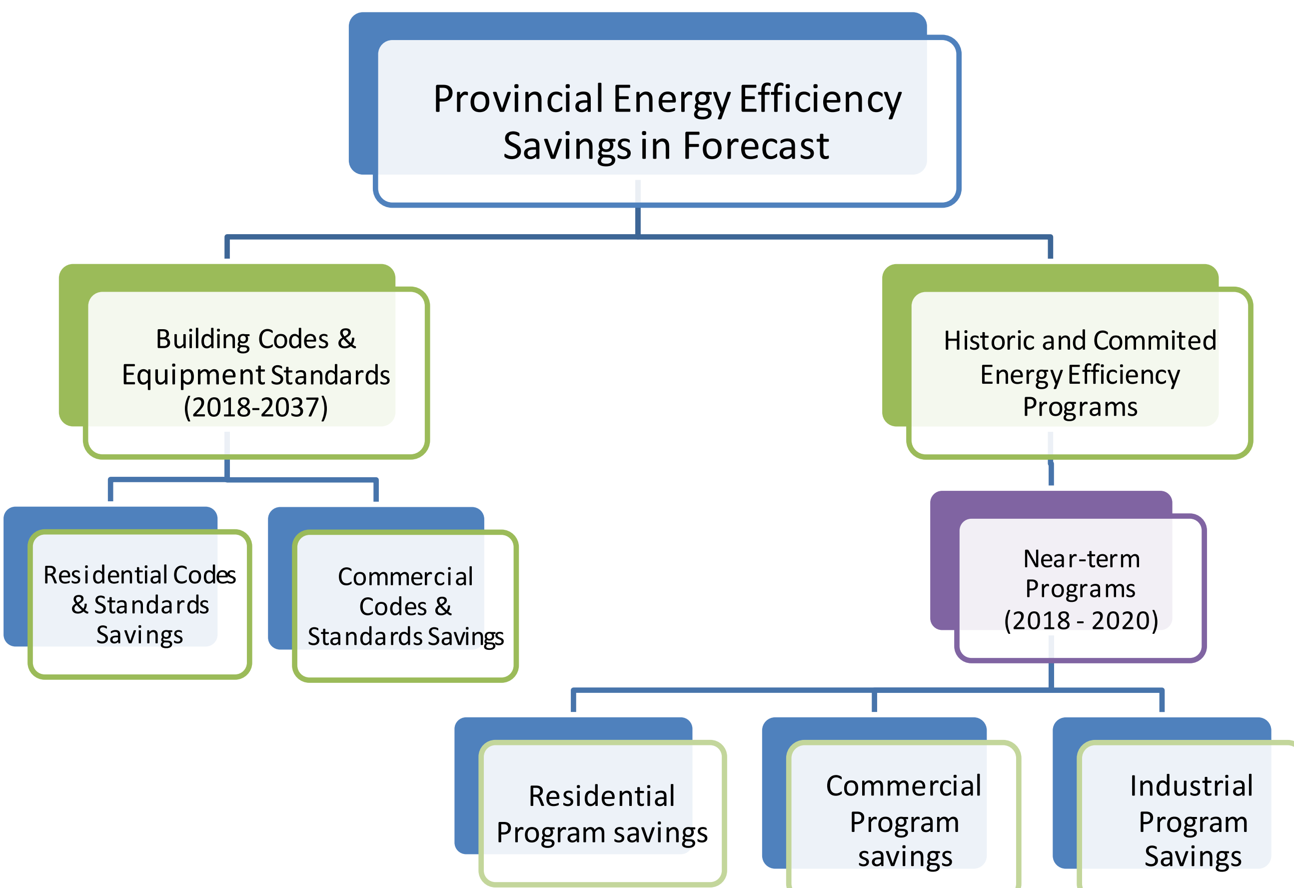
Persistence of these peak-demand savings from energy efficiency programs delivered between 2018-2020 were also considered over the forecast period. The peak demand savings were estimated in the tools for summer demand savings. On future IRRP studies, estimates developed through the Interim Framework 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 were 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 were estimated to occur within this sub-region). When the total peak demand savings for the region had been estimated, it was allocated at each TS according to the relative share of residential, commercial, and industrial gross demand.

B.3.3 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 totalled 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 peak demand for further planning analyses.

Figure B-5: Map of Existing and Committed Energy Efficiency Savings



B.3.4 Forecast Savings from Existing and Committed Energy Efficiency

The forecast peak-demand savings from existing and committed energy efficiency is shown in **Error! Not a valid bookmark self-reference.**. The savings were based on the LDC median gross forecast. Energy efficiency forecast estimates were 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-1: Summer Peak Demand Savings (MW) by TS

Forecast of expected summer peak demand reduction by station (MW)																				
Station	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Armitage TS	3.7	6.6	8.9	9.2	10.1	11.1	11.9	12.8	13.6	14.0	14.1	14.4	14.8	15.4	16.4	16.9	17.4	17.7	17.7	17.7
Brown Hill TS	1.3	2.2	3.0	3.1	3.4	3.8	3.9	4.3	4.5	4.8	4.8	4.9	5.1	5.4	5.7	5.9	6.0	6.1	6.0	5.9
Buttonville TS	1.9	3.6	4.5	4.4	4.8	5.1	5.8	6.2	6.5	6.2	6.0	6.2	6.7	7.2	7.6	7.9	8.1	8.2	8.2	8.2
Holland TS	1.1	2.0	2.7	2.8	3.2	3.5	3.8	4.1	4.4	4.6	4.6	4.8	4.9	5.2	5.6	5.8	6.0	6.2	6.2	6.2
Kleinburg TS	2.4	4.1	5.6	5.7	6.4	7.1	7.5	8.1	8.6	9.0	9.1	9.4	9.8	10.4	11.0	11.4	11.6	11.8	11.8	11.6
Markham MTS #1	1.4	2.5	3.2	3.1	3.3	3.6	3.9	4.0	4.1	3.6	3.1	2.9	3.1	3.3	3.5	3.6	3.7	3.8	3.8	3.8
Markham MTS #2	1.2	2.0	2.6	2.5	2.7	3.0	3.5	3.9	4.1	4.2	4.2	4.5	4.9	5.3	5.7	5.9	6.0	6.1	6.0	6.0
Markham MTS #3	2.8	4.8	5.9	5.8	6.3	6.8	7.8	8.4	8.8	8.4	8.1	8.4	9.1	9.8	10.4	10.7	11.0	11.1	11.1	11.1
Markham MTS #4	1.4	2.7	3.8	4.1	5.0	6.1	6.7	7.0	7.2	6.4	5.6	5.5	5.8	6.2	6.6	6.7	6.9	7.1	7.1	7.1
Markham MTS #5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	2.1	2.9	3.9	5.1	5.6	6.0	6.3	6.5	6.7	8.4	10.1
Richmond Hill MTS	3.0	5.2	7.0	6.9	7.5	8.1	8.6	9.5	10.3	10.0	9.8	10.2	11.1	11.9	12.6	13.0	13.3	13.5	13.5	13.5
Vaughan MTS #1	2.6	4.6	5.8	6.1	7.2	7.7	8.1	9.1	9.5	8.8	8.2	8.3	8.9	9.5	10.1	10.4	10.7	10.9	10.9	10.8
Vaughan MTS #2	1.6	3.1	4.1	4.0	4.3	4.5	4.7	5.2	5.3	4.7	4.2	4.1	4.4	4.6	4.9	5.0	5.2	5.3	5.3	5.3
Vaughan MTS #3	1.4	2.4	3.2	3.3	3.7	4.2	4.6	5.3	5.7	5.8	6.0	6.5	7.1	7.7	8.1	8.4	8.6	8.7	8.7	8.7
Vaughan MTS #4	0.5	1.5	2.1	2.8	3.4	4.6	4.9	5.6	5.9	5.7	5.5	5.7	6.4	6.7	7.1	7.3	7.5	7.6	7.6	7.6
Vaughan MTS #5	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	1.3	2.6	3.9	5.3	6.3	6.3	6.3
Woodbridge TS	1.5	2.9	3.6	3.5	3.7	3.9	4.1	4.2	4.4	3.9	3.4	3.3	3.5	3.7	3.9	4.1	4.2	4.3	4.3	4.3
Total	**28**	**50**	**66**	**67**	**75**	**83**	**90**	**98**	**104**	**102**	**100**	**103**	**111**	**119**	**128**	**133**	**138**	**141**	**143**	**144**

B.4 Final forecast by Station

After taking the median weather forecast provided by LDCs and applying the EE assumptions above, forecasts were adjusted to extreme weather. The final peak demand forecasts, by station, are provided below:

Table B-2: Summer Peak Demand Forecast (MW) by TS

Final Peak Demand Forecast, extreme weather by station (MW)																				
Station	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Armitage TS*	290	297	302	307	312	312	312	312	317	325	331	338	344	350	355	362	368	375	382	389
Brown Hill TS	92	93	94	95	95	95	96	96	96	97	97	98	98	99	99	99	100	100	101	101
Buttonville TS	133	149	148	148	147	147	157	156	156	156	157	157	156	155	155	155	155	154	154	154
Holland TS	141	139	142	145	148	154	160	166	168	168	168	168	168	168	168	168	168	168	168	168
Kleinburg TS	142	143	144	145	146	146	147	147	147	148	149	149	169	169	169	169	169	170	171	172
Markham MTS #1	78	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81
Markham MTS #2	90	95	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101
Markham MTS #3	193	197	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202
Markham MTS #4	87	93	99	128	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Markham MTS #5	0	0	0	0	0	0	0	26	51	77	102	128	153	153	153	153	153	153	186	221
Richmond Hill MTS	228	226	246	246	246	245	245	250	254	254	254	254	254	254	254	254	254	254	254	254
Vaughan MTS #1	255	260	265	275	283	300	306	306	306	306	306	306	306	306	306	306	306	306	306	306
Vaughan MTS #2	131	137	142	151	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Vaughan MTS #3	122	127	132	141	150	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Vaughan MTS #4	43	49	54	63	77	108	141	153	153	153	153	152	153	153	153	153	153	153	153	153
Vaughan MTS #5	0	0	0	0	0	0	0	0	0	0	0	0	2	32	62	94	125	147	147	147
Total	**2024**	**2085**	**2152**	**2228**	**2293**	**2351**	**2406**	**2455**	**2492**	**2526**	**2560**	**2592**	**2646**	**2681**	**2717**	**2755**	**2794**	**2823**	**2865**	**2908**

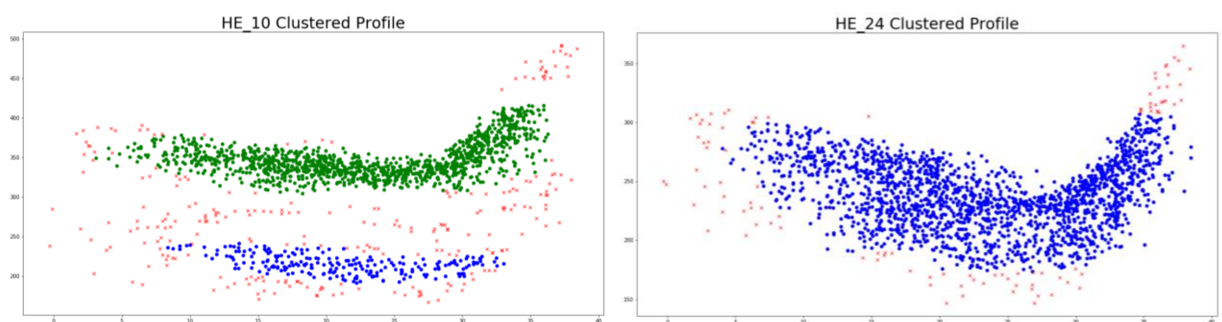
B.5 Duration forecast methodology

B.5.1 General Methodology

At its basis, a load duration forecast consists of a series of year-long hourly profiles ("8760 profile", based on the number of hours in a year), which have been scaled to the appropriate annual peak demand.

Hourly load forecasting was conducted on a station-level, using a multiple linear regression with approximately five 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 B-6, the clustering algorithm helped identify historical load trends when assessing the load vs. humidex relationship.

Figure B-6: Clusters of load vs. humidex for Vaughan #1-3 MTS (used as historical data for Vaughan #4 MTS), during hour 10 and hour 24



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 York 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[2])

[2] Sourced from the Ministry of Finance and Statistics Canada

- Economic factors (employment data[3])

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

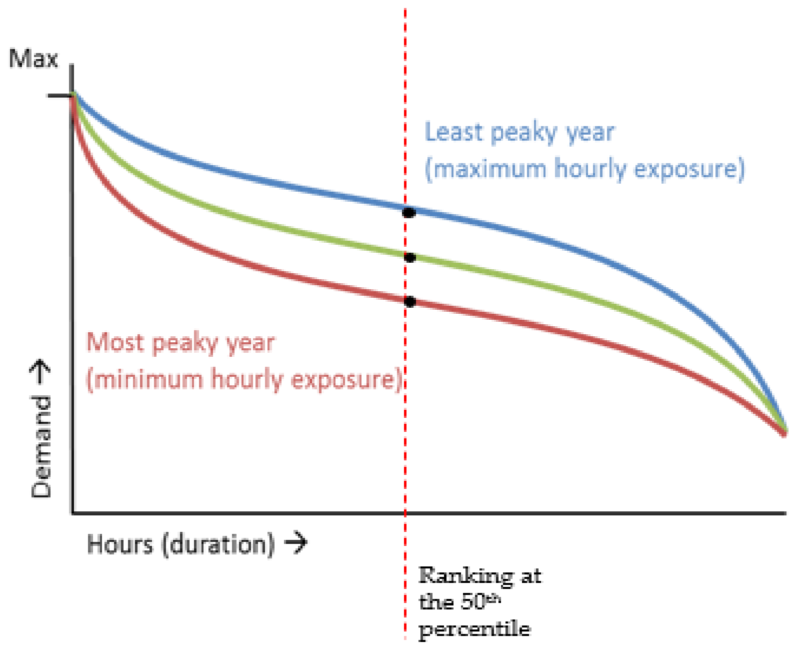
Each future date was first modelled using historical weather data from the equivalent day of year throughout the past 31 years. Additionally, to fully assess the impact of different weather sequences against the other non-weather variables, the historical weather for each of the 31 previous years was shifted both ahead and behind up to seven days, resulting in 15 daily variations. This approach ultimately led to 465 possible hourly load forecasts for *each future year* being forecast. For example:

- $31\ years\ of\ historical\ weather\ data \times 15\ weather\ sequence\ shifts = 465\ weather\ scenarios\ for\ each\ year\ being\ forecast$
- E.g. June 2nd 2025 was forecasted assuming the historical weather from every May 26th to June 9th that occurred between 1988 and 2018.

Each future year's forecasts were normalized to their maximum values, and plotted based on their duration spent above a certain loading. Subsequently, the list of 465 forecasts were ranked in ascending order based on their median values. Load duration curves which illustrate this ranking can be seen in Figure B-7.

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

Figure B-7: Example of Ranking Load Duration Curves Created from Hourly Load Profiles



The forecast in the 3rd percentile was chosen as the "Extreme Peak" (extreme profile, red curve) and the forecast in the 50th percentile was chosen was the "Median Peak" (median profile, green curve).

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

B.5.2 Claireville TS to Brown Hill TS

The development process for the Claireville to Brown Hill load duration forecast differed from the general methodology. Since the load distribution from stations in Northern York was different than the distribution in Vaughan, the accuracy of the forecast was improved by developing individual forecasts for both areas. As such, separate linear regression models were used for the following sub-groupings of stations:

1. Armitage TS, Holland TS, Brown Hill TS and Northern York TS.
    a. Historical load was used from Armitage TS, Holland TS and Brown Hill TS.
2. Vaughan MTS #4 and Vaughan MTS #5.
    a. Historical load was used from Vaughan MTS #1-3.

The general methodology was followed independently for both groups until the set of 465 normalized forecasts were created. They were scaled to the relevant Median weather or Extreme weather maximum loads from the peak demand forecast.

The forecasts from both station groups with the same forecast year, weather conditions (including any shifting) and peak scaling (extreme or median weather) were combined, to create one set of 465 forecasts for extreme weather and another set of 465 forecasts for median weather. The scaled profiles were used to preserve the correct contributions of each station's loading towards the total Claireville-Brown Hill load. At this point, the sets of 465 forecasts included all stations from both sub-groups. The new forecasts were re-normalized, and ranked according to their median values.

The "Extreme Peak" (3rd percentile profile) of the extreme weather forecasts was scaled to the sum of the extreme weather peak demands from both station sub-groups, resulting in a final load duration forecast for the entire Claireville-Brown Hill line, scaled to extreme weather demand and following an extreme weather load profile.

Similarly, the "Median Peak" (50th percentile profile) of the median weather forecasts was scaled to the aggregated median weather peak demand, resulting in a median weather load duration forecast.

B.5.3 Markham

The development process for the Markham forecasts followed the general methodology completely, as there were no distinct sub-groupings of stations.

Historical load data from Markham #1-4 MTS was used to forecast load for Markham #1-5 MTS. Buttonville TS was not included in the analysis.

Appendix C: Options and Assumptions

C.1 Savings Potential from Future Energy Efficiency Programs

To understand the potential impacts of future energy efficiency program opportunities in the province beyond those committed until the end of 2020, the IESO and the OEB recently 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 opportunities (electricity and natural gas), GHG emission reductions and associated costs from demand side resources. The study was 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 2,000 to 3,000 MW in 2038[4] and potential energy savings range from 4 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 were broken out by:

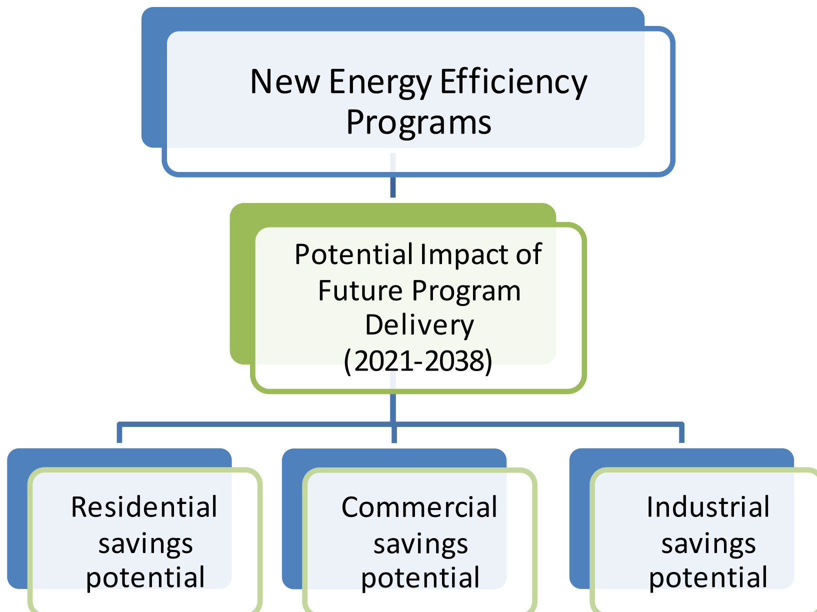
- IESO transmission zone - see map available on the IESO's website here
- Customer segment - e.g., single family dwellings, multi-unit residential buildings, large commercial office, restaurant, school, warehouse, etc.
- End use – e.g., lighting, space heating, space cooling, plug load, etc.
- Measure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

Using local data about composition of businesses, housing and industry in the area, zonal level results have been translated into energy and summer peak demand savings potential estimates for the York IRRP study area. Local data sources used for this analysis in included Municipal Properties Assessment Corporation building data, the Broader Public Sector energy use data, and Dunn and Bradstreet employee counts.

[4] 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).

Based on this analysis, energy efficiency opportunities are expected to be available across all areas and sectors in the IRRP study area.

Figure C-1: Map of Future Energy Efficiency Savings Potential



Tables Table C-1 and Table C-2 below, summarize the summer demand savings opportunities and associated costs by sector for each of the three sub-regions for which new step down stations are forecasted to be needed in the medium to long term as described in the report. Here Vaughan covers the customers served by Vaughan MTSs #1-4, Markham includes customers served by Markham MTSs #1-4 and Northern York includes Armitage, Brown Hill and Holland TSs.

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 GTA and Essa 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 considered 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 provided insight into the magnitude of energy efficiency savings that would be beneficial to the provincial electricity grid and can likely be achieved given customer behaviour.

Table C-1: Summer Peak Demand Savings Potential

Annual Maximum Incremental Cost Effective Achievable Potential (MW)																			
Sub-Region	**Sector**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Vaughan	Residential	0.64	0.73	0.81	0.85	0.87	0.88	0.83	0.83	0.77	0.70	0.72	0.69	0.57	0.48	0.51	0.50	0.46	0.44
	Commercial	1.69	1.60	1.70	1.73	1.80	1.35	1.52	1.42	1.32	1.13	0.91	0.75	0.70	0.33	0.20	0.09	-	-
	Industrial	0.15	0.17	0.18	0.21	0.22	0.22	0.21	0.21	0.18	0.16	0.13	0.11	0.09	0.05	0.01	-	-	-
	Total	2.48	2.50	2.68	2.79	2.89	2.46	2.56	2.45	2.27	1.99	1.77	1.55	1.36	0.86	0.72	0.59	0.46	0.44
Markham	Residential	0.66	0.75	0.83	0.88	0.90	0.90	0.86	0.85	0.79	0.72	0.74	0.70	0.58	0.49	0.52	0.51	0.47	0.45
	Commercial	1.48	1.42	1.50	1.54	1.58	1.31	1.35	1.25	1.14	0.96	0.76	0.61	0.56	0.20	0.07	-	-	-
	Industrial	0.62	0.67	0.73	0.83	0.89	0.90	0.85	0.80	0.69	0.60	0.50	0.42	0.34	0.13	0.04	-	-	-
	Total	2.75	2.85	3.06	3.24	3.36	3.10	3.06	2.90	2.63	2.28	2.01	1.73	1.48	0.82	0.63	0.51	0.47	0.45
Northern York	Residential	0.87	1.01	1.11	1.18	1.21	1.21	1.14	1.12	1.03	0.92	0.94	0.88	0.74	0.63	0.66	0.65	0.60	0.58
	Commercial	2.05	1.97	2.10	2.14	2.21	1.66	1.86	1.72	1.59	1.35	1.09	0.89	0.82	0.37	0.21	0.09	-	-
	Industrial	0.34	0.37	0.40	0.46	0.50	0.50	0.48	0.45	0.39	0.34	0.28	0.24	0.19	0.07	0.01	-	-	-
	Total	3.26	3.35	3.62	3.78	3.92	3.37	3.48	3.29	3.00	2.61	2.31	2.01	1.75	1.07	0.89	0.74	0.60	0.58

Table C-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**
Vaughan	Residential	$2.26	$2.61	$2.93	$3.20	$3.42	$3.63	$3.84	$4.06	$4.24	$4.40	$5.17	$5.31	$5.44	$5.51	$5.58	$5.69	$5.75	$5.92
	Commercial	$4.45	$5.01	$5.61	$5.88	$6.51	$6.48	$6.22	$5.86	$5.37	$4.88	$4.41	$3.98	$3.62	$3.34	$3.08	$2.87	$2.72	$2.61
	Industrial	$0.25	$0.28	$0.31	$0.47	$0.56	$0.59	$0.58	$0.58	$0.54	$0.51	$0.46	$0.42	$0.36	$0.39	$0.32	$0.28	$0.25	$0.20
	Total	$6.96	$7.90	$8.84	$9.55	$10.4	$10.7	$10.6	$10.5	$10.1	$9.79	$10.0	$9.70	$9.41	$9.24	$8.98	$8.84	$8.71	$8.73
Markham	Residential	$2.32	$2.68	$3.00	$3.28	$3.51	$3.73	$3.94	$4.17	$4.35	$4.52	$5.31	$5.45	$5.58	$5.65	$5.73	$5.84	$5.90	$6.08
	Commercial	$4.98	$5.54	$6.12	$6.35	$6.62	$6.55	$6.26	$5.84	$5.34	$4.79	$4.27	$3.80	$3.41	$3.09	$2.82	$2.59	$2.42	$2.27
	Industrial	$0.92	$1.03	$1.14	$1.85	$2.26	$2.35	$2.30	$2.24	$2.13	$1.97	$1.77	$1.58	$1.41	$1.51	$1.30	$1.12	$0.98	$0.83
	Total	$8.23	$9.25	$10.2	$11.4	$12.4	$12.6	$12.5	$12.2	$11.8	$11.2	$11.3	$10.8	$10.3	$10.2	$9.85	$9.55	$9.29	$9.17
Northern	Residential	$2.77	$3.26	$3.66	$3.99	$4.25	$4.48	$4.71	$4.92	$5.09	$5.23	$6.18	$6.32	$6.45	$6.54	$6.64	$6.77	$6.85	$7.10

C.2 Economic Assumptions

The following is a list of the assumptions used for economic evaluations for the different sub-regions in the York IRRP:

- The Net Present Value ("NPV") of the cash flows was expressed in 2019 CAD.
- The NPV analysis was conducted using a 4% real social discount rate.
    - An annual inflation rate of 2% was assumed.
- The USD/CAD exchange rate was assumed to be 0.78 for the study period.
- The life of transformer stations was assumed to be 45 years, the life of a transmission line was assumed to be 65 years, and the life of the Simple Cycle Gas Turbine (SCGT) was assumed to be 30 years.
- The cost of a new 230 kV double circuit transmission line was assumed to be (all $2019): $3.5 million/km for overhead lattice towers, $4.5 million/km for overhead pole towers, and $17 million/km for cable (including reactive compensation)
- The costs of new stations were assumed to be (all $2019): $35 million for greenfield 75/125 Dual Element Spot Network ("DESN") assuming northern York location, and $30 million for greenfield 75/125 DESN assuming southern York location. Assume $5 million could be omitted in both cases where not greenfield (existing site)
- Where comparison between a transmission and resource option was required, an SCGT was used as it was identified as the least-cost resource alternative. The estimated levelized capacity cost assumed is about $195/kW-yr (2019 CAD), based on escalating values from a previous study independently conducted for the IESO.
    - Other resources considered also included utility-scale battery storage with an estimated levelized capacity cost of $207/kW-yr (2019 CAD), based on cost projections from another study independently conducted for the IESO[5]. Since energy storage is energy limited, the installation would need to be oversized in order for the energy storage facility's dispatch duration to meet the identified capacity needs.
- The selection of a resource option for comparison to transmission alternatives did not account for potential operational issues that may arise during planned maintenance activities or forced outages to the unit.
- Natural gas prices were assumed to be an average of $4/MMBtu throughout the study period.

[5] CEATI report "How low can the cost of energy storage go?"

Appendix D: Planning Study Results

The following document is an excerpt of the complete technical study report. The full report is available upon request, but may be subject to confidentiality requirements.

Planning Study

York IRRP Study Results: SUMMARY

Executive Summary, Introduction, Scenarios and Assumptions, References

Prepared by IESO-Transmission Planning

Issue 1.0S

Summary of Initial Release

February 28, 2020

Document ID	
Document Name	York Integrated Regional Resource Plan
Issue	1.0S
Reason for Issue	First Issuance – SUMMARY
Effective Date	February 28, 2020

Document Change History

Issue	Reason for Issue	Date
1.0	First Issuance	February 28, 2020
1.0S	Summary of First Issuance, intended for public release. Full report available upon request, but may be subject to stakeholder approval and/or confidentiality requirements.	February 28, 2020

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1. Executive Summary

1.1 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 York region. The results of this Planning Study will be used to inform the development of planning recommendations in the 2020 York Integrated Regional Resource Plan (the "York IRRP").

For practical purposes, not every forecast year is assessed. Year 1 (2020) is assessed to represent the present-day regional power system, Year 5 (2025) is assessed to represent the near-term planning horizon, Year 10 (2030) is assessed to represent the medium-term planning horizon, and Year 20 (2040) is assessed to represent the long-term planning horizon.

1.2 Scenarios and Assumptions

The Scenarios assessed in this Planning Study are summarized in Table 1.

Table 1: Description of Scenarios Assessed

Scenario Name	Scenario Type	Scenario Description
Scenario 1	Summer peak, extreme weather, long-range forecast	• Demand Outlook (forecast) from Alectra Utilities, Hydro One Distribution, Newmarket-Tay Power • Normal transmission system configuration • York Energy Centre @ 420 MW
Scenario 2	Summer peak, extreme weather, long-range forecast, critical generator outage	• Demand Outlook (forecast) from Alectra Utilities, Hydro One Distribution, Newmarket-Tay Power • Normal transmission system configuration • York Energy Centre @ 370 MW • Flow South @ 0 MW

The study applied planning criteria in accordance with planning events and performance as detailed by:

- North American Electric Reliability Corporation (NERC) 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 (Directory #1), and
- IESO Ontario Resource and Transmission Assessment Criteria (ORTAC).

1.3 Study Results – Existing System

Table 2: Summary of System Needs

Limiting Phenomena	Limiting Contingency	Limiting Element	Study Year Observed
Load Security	V71P and V75P	Vaughan #1 MTS, Vaughan #2 MTS, Richmond Hill #1 MTS, Richmond Hill #2 MTS	2020
Voltage Rise	B88H + B89H	Beaverton TS, Lindsay TS buses	2025
Station LTR	N/A	Armitage TS	2030
Station LTR	N/A	Markham #5 MTS	2030
Voltage Decline	B88H or B89H	Armitage TS	2030
Thermal	L82L88 B/F or L83L89 B/F	H83V or H82V (Vaughan #4 MTS to Woodbridge JCT)	2035
Voltage Decline	H82V + H83V	Armitage TS, Brownhill TS, Beaverton TS, and Lindsay TS buses	2035

1.4 Study Results – Parkway TS to Armitage TS – 230 kV Double Circuit Line

This option involves rebuilding an 20 km idle 115 kV circuit from Parkway TS to Armitage TS to a 230 kV double circuit line (P100A and P101A). Half of Armitage TS will be fed by the new P100A and P101A circuits while the rest will remain served by B88H and B89H. Normally open switches will split the low voltage side of the station. It is expected that this line will be able to serve Buttonville TS, Markham #5 MTS and a future Markham #6 MTS, when needed. Markham MTS #4 is expected to be tapped off directly from Parkway TS. A simplified single line diagram can be found in Figure 1 below.

The studies show that this option is able to address the thermal needs on H83V and H82V as well as the voltage issues summarized by Table 2 above.

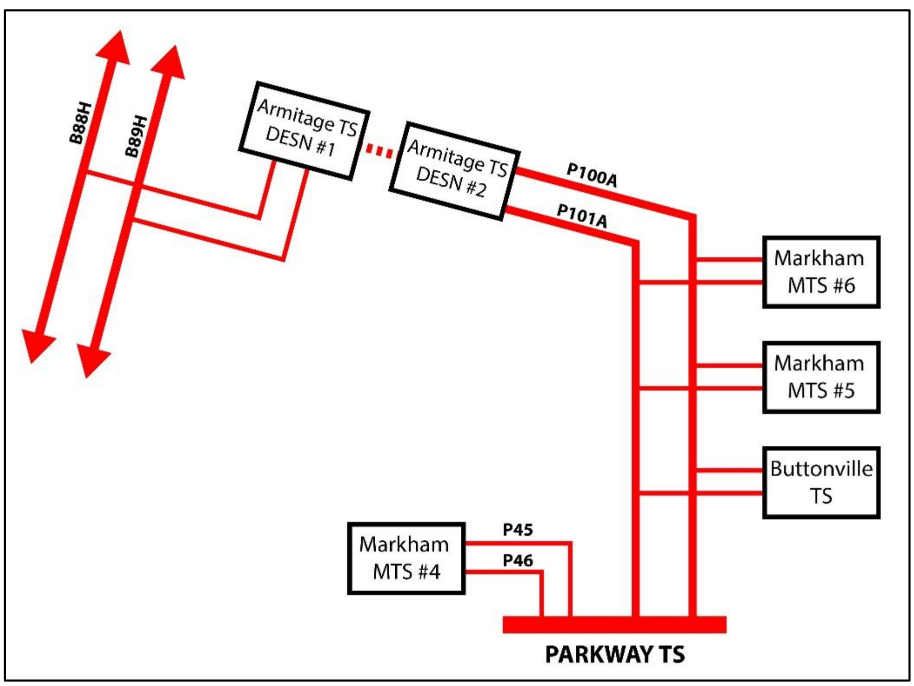

Figure 1 - Simplified SLD for Parkway TS to Armitage TS 230 kV double circuit line

1.5 Study Results – Kleinburg TS to Kirby Link

Another transmission alternative involves sectionalizing the Claireville TS to Brownhill TS circuits with a new 230 kV double circuit transmission link connected westward to the Kleinburg transformer station. This option provides a redundant path for power flowing from Claireville TS northward into northern York, bypassing the heavily loaded and thermally limiting section of H82/83V between Claireville TS and Vaughan 4 MTS (and proposed Vaughan #5 MTS location). As a result, this alternative is often referred to as the Kleinburg to Kirby Link, and is shown in **Error! Reference source not found.** below.

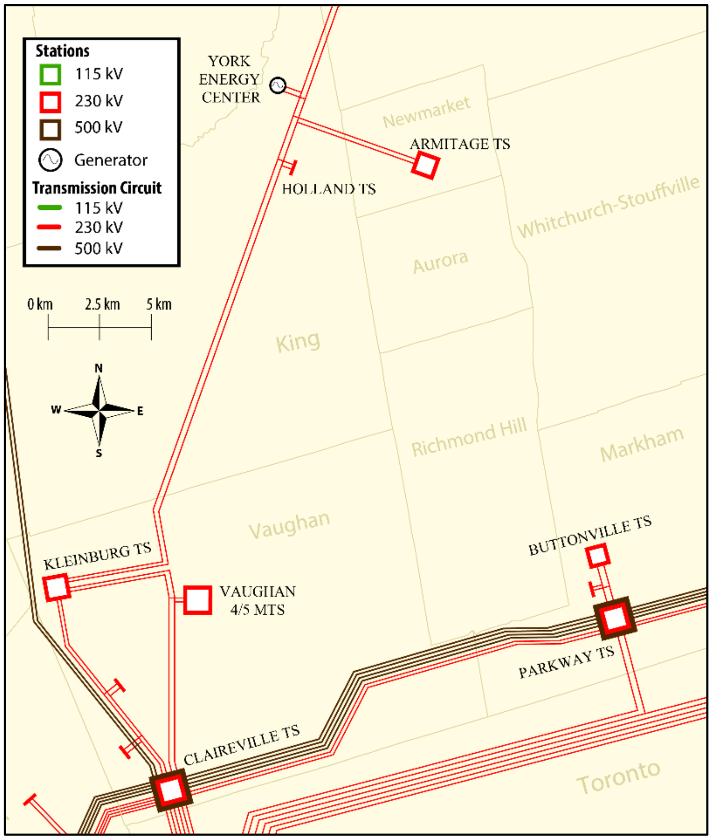

Figure 2 - Simplified SLD for Kleinburg TS to Kirby Link

The new circuits that form the lines from Claireville TS to Kleinberg TS via Vaughan #4 MTS is referred to as "H82VS" and "H83VS" in this report. Similarly, the circuits north of Kleinberg to Holland TS are referred to as "H82VN" and "H83VN" in this report. Throughout the study of this option, the normal station supply of YEC is still assumed to be from distribution level feeders at Holland TS.

It was found that this option can address the circuit thermal needs identified in the needs assessment. Furthermore, it can also substantially alleviate voltage rise issues identified in Table 2. The York Region SPS would have to be expanded to allow for L/R following a V43 or V44 contingency (with one element out pre-contingency) to respect thermal limits.

– End of Section –

2. Introduction

2.1 Purpose

The purpose of this Planning Study report is to document the results of power system analysis studies used to determine the planned performance of the electricity system for the York region. The results of this Planning Study will be used to inform the development of planning recommendations for the 2020 York Integrated Regional Resource Plan (the "York IRRP").

2.2 Limitations

For practical purposes, not every forecast year is assessed. Year 1 (2020) is assessed to represent the present-day regional transmission system; Year 5 (2025) is assessed to represent the near-term planning horizon; Year 10 (2030) is assessed to represent the medium-term planning horizon; and Year 20 (2040) is assessed to represent the long-term planning horizon.

Some inputs to this Planning Study have been provided by entities outside of the IESO. The IESO makes no guarantees as to the quality of inputs provided by entities outside of the IESO.

– End of Section –

3. Scenarios and Assumptions

3.1 Credible Scenarios Assessed

The scenarios presented in Table 3 have been selected for the analysis to establish the planned performance of the electrical system in York relative to recognized planning standards and criteria. The recognized planning standards and criteria are referenced in section 3.5.

Table 3: Description of Credible Scenarios

Scenario Type	Scenario Description
Summer peak, extreme weather, long-range forecast, normal Flow South	• Demand Outlook (forecast) from Alectra Utilities, Hydro One Distribution, Newmarket-Tay Power • York Energy Centre @ 420 MW • Flow South of 1200 MW
Summer peak, extreme weather, long-range forecast, drought Flow South	• Demand Outlook (forecast) from Alectra Utilities, Hydro One Distribution, Newmarket-Tay Power • York Energy Centre @ 370 MW • Flow South of 0 MW

3.2 Facility Ratings Assumptions

Scenarios assumed a load consistent with summer conditions and therefore summer planning ratings are assumed. Winter planning scenarios were not assessed as they are expected to be less limiting than summer scenarios. Facility rating assumptions are summarized in the sub-sections that follow.

3.2.1 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.

3.2.1 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 ACSR conductors or sag (if lower) when the wind speed is less than 4 km/h and ambient temperature is 35°C.

The LTE 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 STE 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.

3.3 System Assumptions

3.3.1 Study Area Scope

The region and municipalities that are covered by this Planning Study is strictly the York Planning Region (or the study area) as shown in Figure 3. A simplified single line diagram of the same study area is shown in Figure 4.

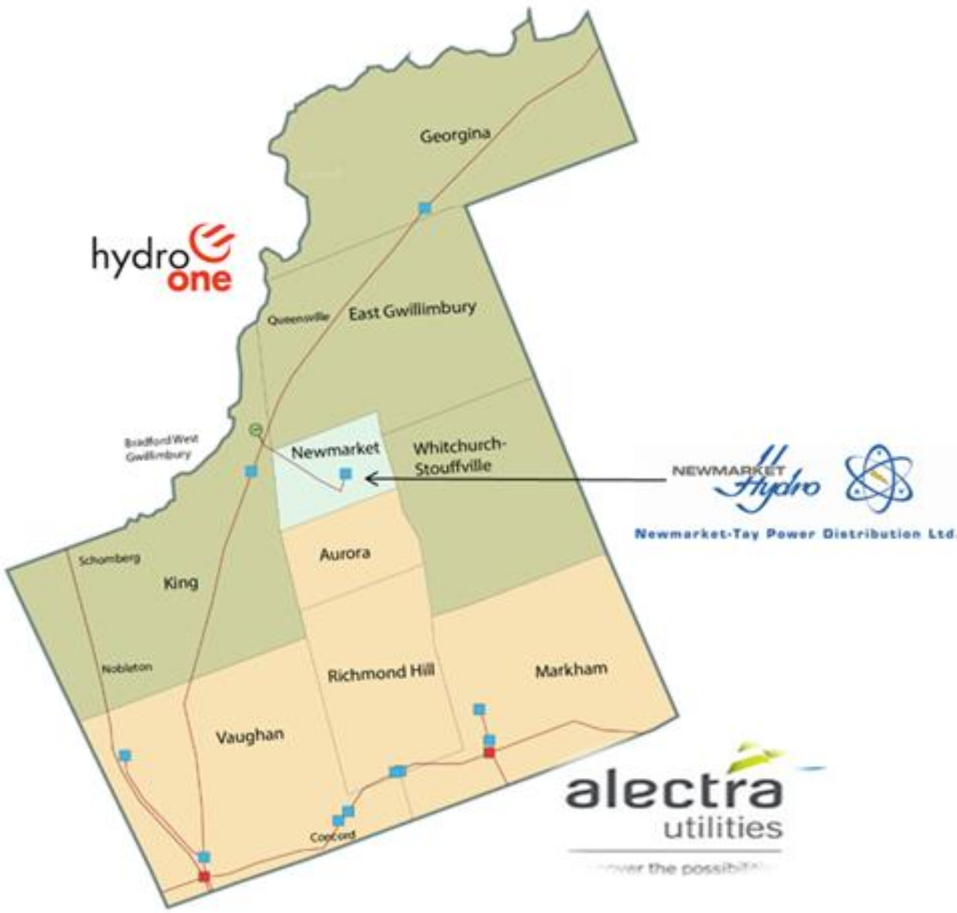

Figure 3 – Study Area Geographical Map

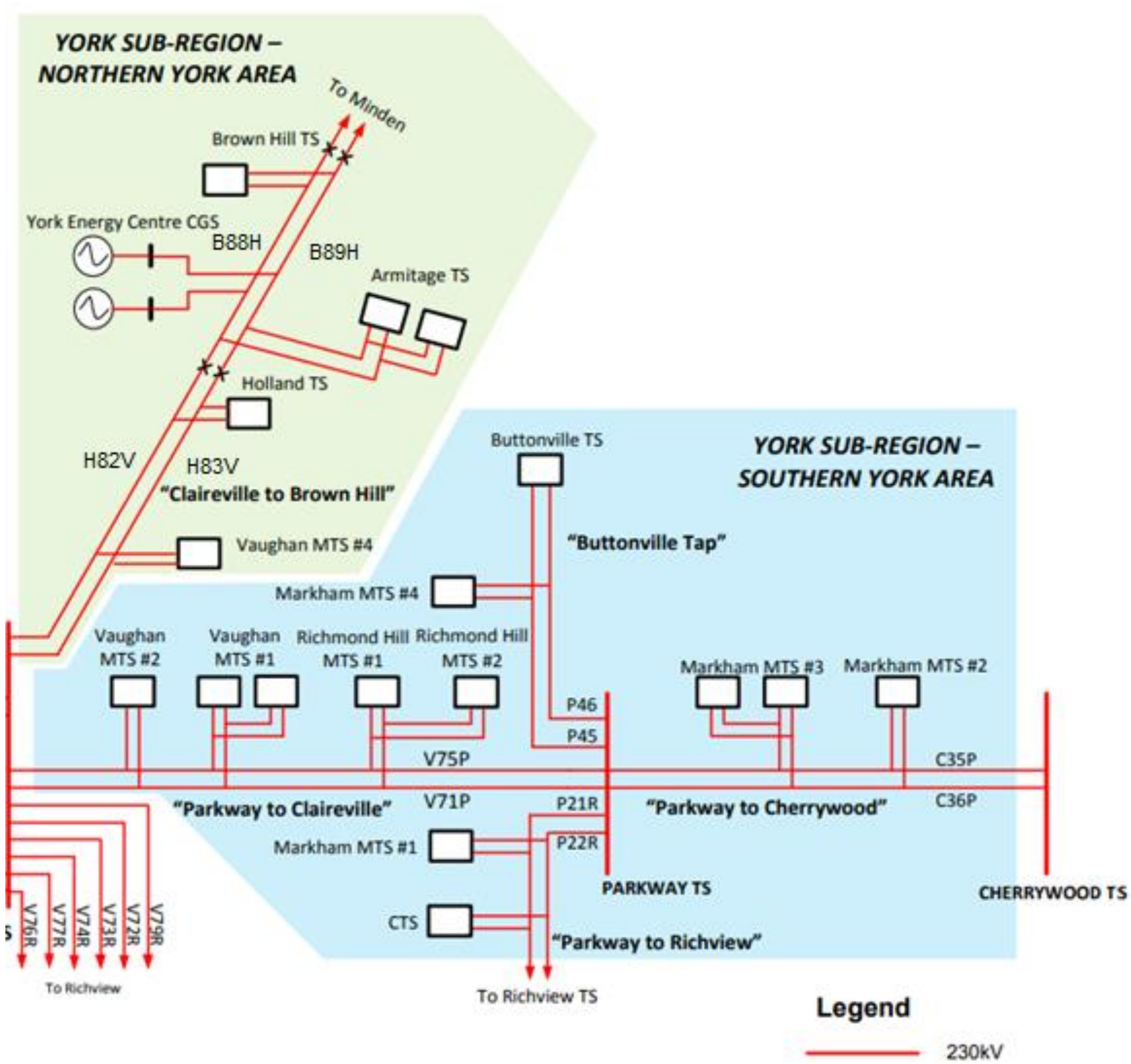

Figure 4 – Study Area 230 kV Transmission System Diagram

3.3.2 Demand Assumptions (Study Area Load)

Scenarios 1, and 2: Demand Outlook as provided by LDCs

The demand forecast was provided by the local distribution companies (LDCs) that are taking part in the York IRRP. The LDCs are Alectra Utilities, Hydro One Distribution, and Newmarket-Tay Power. Active power demand for all four study years are outlined in Table 4, below. A power factor of 0.915 lagging on the low voltage (LV) side is assumed as a reasonable worst-case in order to yield approximately 0.9 lagging without correction on the high voltage (HV) side.

Table 4: Study Area Load by LDC and by Transformer Station

	Forecast Active Power Load [MW]			
Alectra Utilities	**2020**	**2025**	**2030**	**2035**
Kleinburg TS (28kV)	7	7	26	25
Woodbridge TS (28kV)	53	53	56	56
Woodbridge TS (44kV)	75	74	75	74
Holland TS (44kV)	46	55	56	56
Armitage TS (44kV)	104	111	133	150
Richmond Hill MTS (28kV)	246	250	254	254
Vaughan MTS #1 (28kV)	265	306	306	306
Vaughan MTS #2 (28kV)	142	153	153	153
Vaughan MTS #3 (28kV)	132	153	153	153
Vaughan MTS #4 (28kV)	54	153	153	153
Vaughan MTS #5 (28kV)[1]	N/A	N/A	2	147
Buttonville TS (28kV)	148	156	156	154
Markham MTS #1 (28kV)	81	81	81	81
Markham MTS #2 (28kV)	101	101	101	101
Markham MTS #3 (28kV)	202	202	202	202
Markham MTS #4 (28kV)	99	153	153	153
Markham MTS #5 (28kV)[2]	N/A	34	197	199
Hydro One Distribution	**2020**	**2025**	**2030**	**2035**
Kleinburg TS (28kV)	53	54	55	56
Kleinburg TS (44kV)	84	86	87	89
Holland TS (44kV)	33	38	39	39
Armitage TS (44kV)	108	110	114	121
Brown Hill TS (44kV)	94	96	98	100
Newmarket-Tay Power	**2020**	**2025**	**2030**	**2035**
Holland TS (44kV)	63	72	73	73
Armitage TS (44kV)	90	92	96	103

Note that stations Vaughan MTS #5 and Markham MTS #5 are not yet in-service. They are expected to be in-service by the years as indicated in the footnote. For the purpose of performing system studies, Markham MTS #5 is modeled at the same site as Buttonville TS, while Vaughan MTS #5 is expected modeled at the same site as Vaughan MTS #4.

As part of building Markham #5 MTS, Hydro One and Alectra have confirmed that the circuit section from Parkway to Markham #4 MTS (P45-1 and P46-1) need to be upgraded to increase capacity to serve loads at Markham #5 MTS. It is assumed that the conductors on these circuit sections will be

[1] Assumed to be in-service by 2030

[2] Assumed to be in-service by 2025

replaced with 1447.3 kcmil conductors which have summer continuous, LTE, and STE ratings of 1130 A, 1500 A, and 1810 A, respectively.

3.3.3 Generation Assumptions

The York Energy Centre ("YEC") is the only generation facility connected to the transmission system in the York Planning Region. YEC is a simple cycle natural gas-fired facility with two combustion turbine-generators ("YEC G1" and "YEC G2"). YEC is rated at approximately 370 MW in the summer, with both units in-service. For all scenarios, it is assumed that YEC station service is suppled from Holland TS distribution feeders.

The two planning assumptions that are made for YEC are summarized in Table 5.

Table 5: Study Area Generation Assumptions

	Active Power Generation [MW]	
	Scenario 1	Scenario 2
YEC in-service	420	370
One YEC unit out of service	210	N/A

3.3.4 Interface Assumptions

Table 6 below shows the assumed interface flows used in the study.

Table 6: Interface flows

		Interface Active Power Flows [MW]			
Scenario	**Interface**	**2020**	**2025**	**2030**	**2035**
1 and 2	FETT	5500	5500	5500	5500
1	FS	1200	1200	1200	1200
2	FS	N/A	N/A	0	N/A

3.3.5 Study Area Special Protection System (York Region SPS)

Hydro One Transmission implemented the York Region SPS to increase the load-supply capability of the Claireville-Minden corridor; and to improve the capability to restore loads in York Region.

York Region SPS is a Type III SPS. This SPS monitors contingencies on the Claireville-Minden corridor and can trigger load or generation rejection. The SPS will reject selected load feeders by sending load rejection (L/R) signals to Vaughan MTS #4, Holland, Armitage, Brown Hill, and Vaughan MTS #5[3] (once in service) load stations. It rejects generation by sending generation rejection (G/R) signals to YEC. The arming and disarming of the contingencies and the

[3] It is assumed that once Vaughan MTS #5 is in service, it will form part of the York SPS respond to the same L/R signals as Vaughan MTS #4.

load/generation rejection is selected by the IESO operators through the Energy Management System (EMS) Supervisory Control and Data Acquisition (SCADA).

3.4 Credible Planning Events

3.4.1 Steady State Planning Events Studied

For the purpose of this Planning Study, all planning events were studied as Bulk Power System (BPS) elements.

Table 7: Steady State Planning Events Studied

Pre-Contingency State	Contingency
All Elements in-service	Single Element Contingencies (N-1)
	Common Tower Contingencies (N-2)
	Breaker Failure Contingencies (N-2)
One Transmission Element out-of-service	Single Element Contingencies (N-1-1)
One YEC unit out-of-service	Single Element Contingencies (N-G-1)
	Common Tower Contingencies (N-G-2)
	Breaker Failure Contingencies (N-G-2)

3.5 Planning Performance Criteria

The study applied planning criteria in accordance with planning events and performance as detailed by:

- North American Electric Reliability Corporation (NERC) 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 (Directory #1), and
- IESO Ontario Resource and Transmission Assessment Criteria (ORTAC).

– End of Section –

4. References

[1] North American Electric Reliability Corporation TPL-001

[2] Northeast Power Coordinating Council Directory #1

[3] Ontario Resource and Transmission Assessment Criteria (ORTAC)

– End of Section –

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