YORK REGION
INTEGRATED REGIONAL RESOURCE PLAN - APPENDICES

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ieso
Independent Electricity System Operator

York Region IRRP

Appendix A: Demand Forecasts

Appendix A: Demand Forecasts

This Appendix provides details of the methodology and data used to develop the demand forecasts for the York Region IRRP, including the gross demand forecasts provided by LDCs, conservation and distributed generation assumptions, and detailed planning forecasts.

A.1 Gross Demand Forecasts

Appendices A.1.1 through A.1.3 were prepared by the LDCs and describe their methodologies to prepare the gross demand forecast used in this IRRP. Gross demand forecasts by station are provided in Appendix A.1.4.

A.1.1 PowerStream's Gross Demand Forecast Methodology

PowerStream is jointly owned by the municipalities of Barrie, Markham and Vaughan, and is the second largest municipally-owned electricity distribution company in Ontario. PowerStream provides power and related services to more than 370,000 customers residing or owning businesses in communities located immediately north of Toronto and in Central Ontario. PowerStream serves communities including Alliston, Aurora, Barrie, Beeton, Bradford West, Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan, as well as Collingwood, Stayner, Creemore and Thornbury through a partnership with the Town of Collingwood in the ownership of Collus PowerStream.

This study focuses only on the York Region area. PowerStream's service territory in York Region is composed of three distinct municipal districts (Vaughan, Markham and Richmond Hill) that have 28 kV distribution lines, as well as an Aurora district that has a 44 kV sub-transmission system. Aurora is supplied by five 44 kV feeders originating from Armitage TS in Newmarket.

The electric load forecast is one of the key drivers of PowerStream's planning activities. The primary purpose of the electricity load forecast is to address the key questions of: when, where, why and how much electricity will be required on the PowerStream system to allow PowerStream to evaluate planning alternatives and to ensure that there is sufficient capacity on the system to supply customers in a reliable and cost effective manner.

The reference level forecast was performed using two different methods of forecasting to determine if there was some convergence to a forecast load at the end of the study period, specifically:

- past system peak performance and trend (statistical) analysis; and
- end-use analysis using the latest information available from municipal reports.

The reference level forecast takes into account impacts from growth, weather, DG and conservation as follows:

Growth

Four municipalities (Markham, Richmond Hill, Vaughan and Aurora) projected the residential and non-residential development in their development charge background studies. These developments are the main drivers of electrical load growth in the PowerStream service territory. PowerStream's annual residential and non-residential load growths were forecast by multiplying unit usage for residential and watts per square foot for non-residential development. The annual projected load is expressed as a percentage of the existing load. The total growth over the forecast horizon is averaged out to an annual growth rate. The growth rate is also adjusted according to current market conditions.

Weather

PowerStream's summer system peaks invariably coincide with hot weather conditions (high temperatures). While other factors may be playing a part, peak demands are being driven largely by the use of air conditioning. Prolonged periods of hot weather present the biggest challenge to the reliability of PowerStream's distribution system when a significant number of customers are using their home and workplace air conditioners simultaneously, and diversity of operation between customers is lost.

Since long-term weather cannot be forecast, weather scenarios (normal and extreme summer) are created based on historical weather data.

Historical electrical peaks are weather normalized to account for weather impact.

An electricity distribution system should be able to maintain the supply to customers not only under normal weather, but also under extreme weather conditions. Electrical load forecasts under normal summer weather are created and provided to the IESO. Electrical load forecasts under extreme weather are produced by IESO utilizing algorithms.

Conservation and Demand Management (CDM)

PowerStream's load forecast is performed using the current year's actual peak (weather normalized) as a starting point. The impact of CDM programs in the previous years has been reflected in the actual peak.

PowerStream's CDM Strategy 2011 to 2014 Report has been filed and approved by the OEB. To meet its CDM target, PowerStream (including areas the utility serves outside of York Region) will achieve a 90 MW reduction in peak demand from 2011 to 2014.

PowerStream has a new target for post 2014. The new target is to achieve 535.4 GWh of energy savings persisting to 2020 by 2020.

The forecast provided by PowerStream does not include the impacts of conservation from 2014 onward. Conservation assumptions were developed by the IESO and applied to PowerStream's load forecast.

Distributed Generation (DG)

PowerStream will build new capacity when and where load is projected to occur. If DG is located near the load growth, it can reduce the need for new capacity. Thus, PowerStream can defer investments in wire-delivery facilities by relying on DG, at least for a short period of time, if not indefinitely.

PowerStream's load forecast is performed using the current year's actual peak (weather normalized) as a starting point. The impact of existing DG has been reflected in the actual peak.

The IESO will apply the effective impact of future DG on PowerStream's load forecast.

A.1.2 Newmarket-Tay Distribution Ltd. Gross Forecast Methodology

Introduction

Newmarket-Tay Power Distribution Ltd. ("NT Power") owns and operates the electricity distribution system within its OEB licensed 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). For the purpose of this study, the focus is only on the Newmarket Service Area. NT Power serves approximately 26,000 Residential and General Service customers within the Newmarket Service Area.

Community in Transition

The Town of Newmarket has been designated as an Urban Growth Centre under the Province of Ontario's Places to Grow strategy and as an area where future growth and intensification is to be directed. The Yonge St. and Davis Dr. corridors have been identified as one of four Regional Centres in the York Region Official Plan.

The Town of Newmarket is currently planning for the revitalization of Newmarket's Urban Centers which will shape the future of the community. The town has recently adopted a new Secondary Plan that sets ambitious targets for population and employment growth within its centres and corridors - primarily along Yonge St. and Davis Dr. The Secondary Plan will result in increased density (e.g., population and jobs) to meet the minimum density provisions of the Growth Plan (200 persons and jobs per hectare) and the Region of York Official Plan growth policies. For the purpose of this study, NT Power used the projections that meet provincial and regional planning requirements as developed by the Town of Newmarket through the Secondary Plan process.

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 is the basis of this load forecast with further analysis associated with Newmarket's Secondary Plan. For the current load forecast the coincident peak data from 2013 has been used as the base for the load forecast. In developing the load forecast several factors must be considered and evaluated to determine potential growth within the service area. The electric load forecast is 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 uses historical consumption of electricity demand to predict future requirements. A combination of timeframes (5, 10, 15 years) is used to determine potential demand increases as compared to forecast growth. Regular updating and review is completed on an annual basis.

A second analysis is completed based on customer end use. 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.

The end-use analysis methodology considers that the demand for electricity is dependent on what it is used for. An analysis is completed on end-use usage and demand is subsequently allocated between residential and industrial/commercial/institutional ("ICI") type demand. Using standard historical usage data per end-use customer provides a basis to forecast expected demand with load growth across both residential and industrial ICI demand.

A.1.3 Hydro One Distribution Gross Forecast Methodology

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

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

A.1.4 Gross Forecasts, by Sub-Area and Station

Table A-1: Gross Demand Forecasts (MW)

NORTHERN YORK REGION	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Load (normal weather)																				
Holland TS	128	131	134	137	141	143	147	150	154	157	161	164	168	171	175	178	181	183	185	187
Armitage TS	277	284	290	298	305	312	319	327	335	344	350	358	365	372	380	387	395	401	408	414
Brown Hill TS	78	80	83	86	89	92	95	98	102	105	109	112	116	120	124	128	133	137	141	146

VAUGHAN/RICHMOND HILL	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Load (normal weather)																				
Richmond Hill MTS	238	238	238	238	238	238	238	238	238	238	238	238	238	238	238	238	238	238	238	238
Vaughan 1 MTS	290	310	327	356	373	396	421	447	473	500	520	540	562	582	603	619	636	653	669	687
Vaughan 2 MTS	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143
Vaughan 3 MTS	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143

*All new PowerStream growth in Vaughan area was assigned to Vaughan 1/1E, the newest station

MARKHAM	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Load (normal weather)																				
Buttonville TS	112	131	131	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143
Markham 1 MTS	84	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
Markham 2 MTS	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Markham 3 MTS	178	189	189	189	189	189	189	189	189	189	189	189	189	189	189	200	189	189	189	189
Markham 4 MTS	74	76	100	115	143	168	193	218	244	272	292	312	331	353	375	382	409	426	444	461

*All new PowerStream growth in Markham area was assigned to Markham 4 MTS, the newest station

A.2 Conservation

The forecast conservation savings included in the demand forecasts for the York Region IRRP were derived from the provincial conservation forecast, which aligns with the conservation targets described in the 2013 LTEP: "Achieving Balance: Ontario's Long-Term Energy Plan". The LTEP set an electrical energy conservation target of 30 TWh in 2032, with about 10 TWh of the energy savings coming from codes and standards ("C&S"), and the remaining 20 TWh from energy efficiency ("EE") programs. The 30 TWh energy savings target will also lead to associated peak demand savings. Time-of-Use ("TOU") rate impacts and Demand Response resources are focused on peak demand reduction rather than energy savings and, as such, are not reflected in the 30 TWh energy target and are considered separately in forecasting.

To assess the peak demand savings from the provincial conservation targets, two demand forecasts are developed. A gross demand forecast is produced that represents the anticipated electricity needs of the province based on growth projections, for each hour of the year. This forecast is based on a model that calculates future gross annual energy consumption by sector and end use. Hourly load shape profiles are applied to develop province-wide gross hourly demand forecasts. Natural conservation impacts are included in the provincial gross demand forecast, however the effects of the planned conservation are not included. A net hourly demand forecast is also produced, reflecting the electricity demand reduction impacts of C&S, EE programs, and TOU. The gross and net forecasts were then compared in each year to derive the peak demand savings. In other words, the difference between the gross and net peak demand forecasts is equal to the demand impacts of conservation at the provincial level.

The above methodology was used to derive the combined peak demand savings, which was further broken down to three categories as shown in Table-1. Peak demand savings associated with load shifting in response to TOU rates were estimated using an econometric model based on customers' elasticity of substitution and the TOU price ratio. The remaining peak savings were allocated between C&S and EE programs based on their energy saving projections, with about 1/3 attributed to C&S and 2/3 to EE programs.

The resulting peak demand savings in each year are represented as a percentage of total provincial peak demand in Table A-2, using 2013 as a base year.

Table A-2: Peak Demand Savings from Provincial Conservation Targets (% of load)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
C&S	0.0%	0.2%	0.5%	0.6%	1.1%	1.6%	1.9%	2.3%	2.5%	2.6%	2.8%	2.9%	3.1%	3.6%	4.1%	4.4%	4.8%	5.1%	5.4%	5.4%
TOU	0.2%	0.3%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
EE programs	0.5%	0.8%	1.0%	1.1%	1.3%	2.1%	3.1%	3.2%	3.6%	4.2%	5.0%	5.3%	5.8%	6.0%	6.5%	6.6%	6.9%	7.4%	7.8%	7.8%
Total	0.8%	1.3%	1.9%	2.2%	2.7%	4.1%	5.4%	5.9%	6.5%	7.1%	8.1%	8.6%	9.3%	10.0%	11.0%	11.4%	12.1%	12.8%	13.5%	13.5%

These percentages were applied to the gross demand forecasts provided by the York Region LDCs at the transformer station level to determine the peak demand savings assumed in the planning forecast. This allocation methodology relies on the assumption that the peak demand savings from provincial conservation will be realized uniformly across the province. Actions recommended in the York Region IRRP to monitor actual demand savings, and to assess conservation potential in the Region, will assist in developing region-specific conservation assumptions going forward.

Existing DR resources are included in the base year and gross demand forecasts. Additional DR resources can be considered as potential options to meet regional needs.

A.2.1 Conservation Assumptions by Sub-Area and Station

The following tables show the expected peak demand impact of provincial energy targets at each transformer station, developed according to the methodology described in Appendix A.2 above, for the purposes of the high-growth forecast.

Table A-3: Conservation Assumptions (MW)

NORTHERN YORK REGION	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Conservation (normal weather)																				
Holland TS	1	2	3	3	4	6	8	9	10	11	13	14	16	17	19	20	22	23	25	25
Armitage TS	2	4	6	6	8	13	17	19	22	24	28	31	34	37	42	44	48	51	55	56
Brown Hill TS	1	1	2	2	2	4	5	6	7	7	9	10	11	12	14	15	16	18	19	20

VAUGHAN/RICHMOND HILL	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Conservation (normal weather)																				
Richmond Hill MTS	2	3	5	5	7	10	13	14	15	17	19	21	22	24	26	27	29	31	32	32
Vaughan 1 MTS	2	4	6	8	10	16	23	26	31	35	42	47	52	58	66	71	77	84	91	93
Vaughan 2 MTS	1	2	3	3	4	6	8	8	9	10	12	12	13	14	16	16	17	18	19	19
Vaughan 3 MTS	1	2	3	3	4	6	8	8	9	10	12	12	13	14	16	16	17	18	19	19

MARKHAM	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Conservation (normal weather)																				
Buttonville TS	1	2	2	3	4	6	8	8	9	10	12	12	13	14	16	16	17	18	19	19
Markham 1 MTS	1	1	1	2	2	3	4	4	5	5	6	7	7	8	8	9	9	10	10	10
Markham 2 MTS	1	1	2	2	3	4	5	6	6	7	8	8	9	10	10	11	11	12	13	13
Markham 3 MTS	1	3	4	4	5	8	10	11	12	13	15	16	18	19	21	23	23	24	26	26
Markham 4 MTS	1	1	2	2	4	7	10	13	16	19	24	27	31	35	41	44	49	55	60	63

A.3 Distributed Generation

As of February 2014, the IESO (former OPA) had awarded 82 MW of DG contracts within the York Region study area. Of these, 22 MW had already reached commercial operation. Since LDCs were producing their demand forecasts to align with actual peak demand, any DG already in service during the most recent year's peak hour would already be accounted for in gross forecasts. As a result, only contracts for projects which had not yet reached commercial operation at the time the forecasts were produced needed to be incorporated.

Contract information provided the rated (installed) capacity, generation fuel type (solar and natural gas), connecting station, and maximum commercial operation date ("MCOD") for each project. For the purposes of this study, it was assumed that all active contracts would be connected on their MCOD. This was a conservative assumption, as some attrition would normally be expected from a field of over 130 contracts. While natural gas projects can be assumed to contribute their full installed capacity during summer peak, local weather conditions can greatly impact the contribution of solar projects to meeting demand. For the York Region IRRP, the IESO relied upon the summer Solar Capacity Contribution ("SCC") values, as described in section 3.2.2 of the 2014 Methodology to Perform Long Term Assessments[1] (copied below):

> Monthly Solar Capacity Contribution (SCC) values are used to forecast the contribution expected from solar generators. SCC values in percentage of installed capacity are determined by calculating the simulated 10-year solar historic median contribution at the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. As actual solar production data becomes available in future, the process of picking the lower value between actual historic solar data, and the simulated 10-year historic solar data will be incorporated into the SCC methodology until 10-years of actual solar data is accumulated, at which point the simulated solar data will be phased out of the SCC calculation.

Based on the current methodology, summer peak SCCs of 34% were assumed. After consideration of anticipated peak contribution of each contract, the total effective capacity for all active, unconnected DG contracts was estimated on a station by station basis. Consideration

[1] http://www.ieso.ca/Documents/marketReports/Methodology_RTAA_2014feb.pdf

was also given to anticipated in-service year, to ensure the effect of the project is not observed until the MCOD date. The final DG forecast is shown in Appendix A.3.1.

A.3.1 Distributed Generation Assumptions by Sub-Area and Station

The following tables show the expected peak demand impact of DG contracts which were active as of February 2014, but which had not yet reached commercial operation. These contributions were subtracted from the gross demand forecasts on a station by station basis.

Table A-4: Distributed Generation Assumptions (MW)

NORTHERN YORK REGION	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Distributed Generation																				
Holland TS	0.32	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78
Armitage TS	2.38	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66
Brown Hill TS	10.2	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5

VAUGHAN/RICHMOND HILL	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Distributed Generation																				
Richmond Hill MTS	0.00	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
Vaughan 1 MTS	0.10	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86
Vaughan 2 MTS	0.58	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Vaughan 3 MTS	0.00	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45

MARKHAM	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Distributed Generation																				
Buttonville TS	0.24	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	0.30	0.30
Markham 1 MTS	0.25	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Markham 2 MTS	3.47	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51
Markham 3 MTS	2.65	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08
Markham 4 MTS	0.00	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07

A.4 Planning Forecasts

Two planning level forecasts were developed for the York IRRP: a high-growth forecast; and a low-growth forecast.

The high-growth forecast is the primary forecast used for carrying out system studies, and was based on gross demand forecast by LDCs within their service territories. The underlying growth projections upon which this forecast is based are consistent with municipal growth plans, which in turn are in alignment with *Places to Grow, the Provincial Growth Plan for the Greater Golden Horseshoe*. The LDC forecasts were adjusted by the IESO to account for the anticipated peak demand impacts of provincial energy targets, the effect of contracted distributed generation, and effect of extreme weather conditions.

The low-growth forecast was prepared by the IESO by applying the percentage annual growth rates predicted by the demand forecast model underlying the LTEP for the broader Central Ontario and GTA zones, and applying these growth rates uniformly across the load centres. Because York Region overlaps with both of these zones, the growth rate for the Toronto zone was used for Southern York Region (roughly corresponding with the municipalities of Vaughan, Richmond Hill, Markham, and Buttonville), and the growth rate for Central Ontario was used for Northern York Region (roughly corresponding with the municipalities of Whitchurch-Stouffville, Georgina, East Gwillimbury, Newmarket, and King).[2] Zonal growth rates were prepared based on direction provided in the 2013 LTEP, and they account for anticipated peak demand impacts of new Conservation programs. Because this forecast does not allow for variations in growth levels within a planning area, and instead applies the same growth rate across a large zone, this forecast does not provide the same precision or benefits of local knowledge as the high-growth forecast. As a result, this forecast was used as a long term (2024-2033) sensitivity scenario, to account for the lower level of certainty associated with development plans prepared over a decade in advance. Since this forecast made use of a percentage growth factor, it was required to assume a starting value for station demand in 2023. In order to align this long term forecast with the common near/mid-term forecast, the high-growth forecast was used as the starting point.

[2] The northern and southern sub-regional boundaries in this study are based on electrical boundaries and do not correspond directly with the municipal boundaries.

In both forecasts, the final demand allocated to PowerStream stations was adjusted to account for load transfers and typical station loading practices. This ensures that a station already at full capacity would continue at full utilization, even if incremental peak demand reducing measures (conservation and DG) would have produced a net decrease in load. The IESO worked with PowerStream to understand and implement transfers consistent with their expected operation.

The final high-growth and low-growth forecasts are provided in Appendices A.4.1 and A.4.2, respectively.

A.4.1 High-Growth Planning Forecast by Sub-Area and Station

Table A-5: High-Growth Planning Forecast (MW)

NORTHERN YORK REGION Net Load (Extreme)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Holland TS	134	136	138	142	144	145	146	149	152	154	156	158	160	162	164	166	168	168	169	170
Armitage TS	289	294	299	306	312	314	317	324	330	336	338	344	349	352	356	361	365	368	371	377
Brown Hill TS	72	74	76	79	81	83	85	88	90	93	95	98	101	104	107	110	113	116	119	123

VAUGHAN/RICHMOND HILL Net Load (Extreme)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Richmond Hill MTS	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254
Vaughan 1 MTS	287	306	306	306	306	306	306	306	306	306	306	306	306	306	306	306	306	306	306	306
Vaughan 2 MTS	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Vaughan 3 MTS	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Vaughan 4 MTS	0	0	24	47	69	83	97	119	140	160	170	185	200	212	222	233	241	248	256	272

MARKHAM Net Load (Extreme)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Buttonville TS	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Markham 1 MTS	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81
Markham 2 MTS	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101
Markham 3 MTS	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202
Markham 4 MTS	24	42	62	89	112	125	137	158	178	198	207	220	232	244	255	265	273	279	287	303

A.4.2 Low-Growth Forecast by Sub-Area and Station

Table A-6: Low-Growth Planning Forecast (MW)

NORTHERN YORK REGION Net Load (Extreme)	2023 (Places to Grow)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Holland TS	154	153	153	153	153	152	152	152	152	152	152
Armitage TS	336	334	334	334	333	332	332	332	331	330	333
Brown Hill TS	93	93	93	93	92	92	92	92	92	92	92

VAUGHAN/RICHMOND HILL Net Load (Extreme)	2023 (Places to Grow)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Richmond Hill MTS	254	254	254	254	254	254	254	254	254	254	254
Vaughan 1 MTS	306	306	306	306	306	306	306	306	306	306	306
Vaughan 2 MTS	153	153	153	153	153	153	153	153	153	153	153
Vaughan 3 MTS	153	153	153	153	153	153	153	153	153	153	153
Vaughan 4 MTS	160	162	168	173	177	179	186	190	194	198	210

MARKHAM	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Net Load (Extreme)	(Places to Grow)										
Buttonville TS	153	153	153	153	153	153	153	153	153	153	153
Markham 1 MTS	81	81	81	81	81	81	81	81	81	81	81
Markham 2 MTS	101	101	101	101	101	101	101	101	101	101	101
Markham 3 MTS	202	202	202	202	202	202	202	202	202	202	202
Markham 4 MTS	198	200	207	213	218	220	228	234	238	242	256

York Region IRRP

Appendix B: Needs Assessment

Appendix B: Needs Assessment

This Appendix provides information on the methodology and data used to assess needs in the York Region IRRP.

B.1 Station Capacity Assessment

In order to assess the need for additional transformer station capacity, planning forecasts were compared to the 10-day limited time rating ("LTR") of the stations in the Region. In order to account for transfer capability between adjacent stations, three groupings of stations were considered:

- **Northern York Region:** Holland TS, and Armitage TS.[3]
- **Vaughan:** Vaughan #1, #2, and #3 stations for the near term; in the medium and long term, the new Vaughan #4 station was also assumed to be available.
- **Markham/Richmond Hill:** Markham #1, #2, #3, and #4 stations, Richmond Hill MTS, and Buttonville TS.

For each of these station groupings, the combined capacities of the stations were compared against the combined planning forecasts at the included stations to determine when new station capacity is likely to be needed.

B.1.1 Near-Term Station Capacity Assessment (2014-2018)

In the near term, station capacity is forecast to be exceeded beginning around 2016 in Vaughan. There is adequate station capacity in Markham/Richmond Hill and Northern York Region in the near term.

Subareas	Combined Station LTR (MW)	Near-Term Planning Forecast 2014-2018 (MW)				
		2014	2015	2016	2017	2018
Markham/Richmond Hill	944	815	833	853	880	903
Northern York Region	485	423	430	437	448	456
Vaughan	612	593	612	636	659	681

[3] Brown Hill TS is not included in the Northern York Region group due to its distance from the Holland and Armitage stations. Brown Hill TS has adequate station capacity to accommodate forecast growth throughout the 20-year planning period.

B.1.2 Medium and Long-Term Station Capacity Assessment (2019-2033): High-Growth Scenario

Under the high-growth scenario, station capacity is forecast to be exceeded in Markham/Richmond Hill beginning around 2021, and in Northern York Region and Vaughan around 2023.

Sub-areas	Combined Station LTR (MW)	High-Growth Scenario 2019-2033 (MW)														
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Markham/Richmond Hill	**944**	916	928	949	969	989	998	1011	1023	1035	1046	1056	1064	1070	1078	1094
Northern York Region	**485**	459	463	473	481	490	494	502	509	515	520	527	533	536	540	547
Vaughan	**765**	695	709	731	752	772	782	797	812	824	834	845	853	860	868	884

B.1.3 Medium and Long-Term Station Capacity Assessment (2019-2033): Low-Growth Scenario

Under the low-growth scenario, station capacity is forecast to be exceeded in Markham/Richmond Hill beginning around 2021, and in Vaughan around 2023. Station capacity is expected to be adequate throughout the study period in Northern York Region under this scenario.

Sub-areas	Combined Station LTR (MW)	Low-Growth Scenario 2019-2033 (MW)														
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Markham/Richmond Hill	**944**	916	928	949	969	989	991	998	1004	1009	1011	1019	1025	1029	1033	1047
Northern York Region	**485**	459	463	473	481	490	487	488	487	486	484	485	484	483	482	485
Vaughan	**765**	695	709	731	752	772	774	780	785	789	791	798	802	806	810	822

B.2 System Load Flow Base Case Setup and Assumptions

The system studies for this IRRP were conducted using PSS/E Power System Simulation software. The reference PSS/E case was adapted from the 2015 base case that was produced by the IESO for the 2010 Northeast Power Coordinating Council ("NPCC") Review. This load flow includes all eight Bruce nuclear units and the new 500 kV double-circuit line between the Bruce Complex and Milton SS. All the units at Darlington are assumed to be in-service, and all of the units at the Pickering generating station are assumed to be unavailable due to their scheduled retirement as early as 2015. Summer ambient conditions of 35°C and 4 km/hr wind for overhead transmission circuits were assumed in this study. For transformers, 10-day LTRs are respected under post-contingency conditions.

In additional to the bulk system assumptions, the base case includes the following recent changes and specific characteristics of the York Region system:

- Both units at York Energy Centre (YEC)—G1 and G2—were included in the study. Under YEC's current connection configuration, the bus tie between G1 and G2 is normally open and does not have the capability to provide backup under N-1 contingency conditions.
- Due to declining gas feedstock from the landfill site that is its fuel source, the output of the Keele Valley Generating Station is uncertain, particularly in the later years of the study. Therefore, this facility was assumed to be out of service.
- Des Joachim GS and southbound flows on the North-South Tie Interface contribute to the area supply at the northern end of the Claireville-to-Minden system. For this study, the North-to-South flow was assumed to be about 1,530 MW, and the output of Des Joachim GS was assumed to be 280 MW (~78% of installed capacity).
- All capacitor banks at Armitage TS, Holland TS, Beaverton TS and Lindsay TS were assumed to be in service.

B.3 Load Meeting Capability of the Claireville-to-Minden System

B.3.1 Application of Planning Criteria

In the Claireville-to-Minden system, supply capacity is provided by both the transmission system, as well as the two generating units at York Energy Centre.

In accordance with ORTAC, the system must be designed to provide continuous supply to a local area under specific transmission and generation outage scenarios. The ORTAC criteria governing supply capacity for local areas are presented in Table B-1. For areas with local generation, such as the Claireville-to-Minden system, ORTAC gives credit to the supply capacity provided by local generation by allowing controlled load rejection as an operational measure under specified outage conditions.

The performance of the system in meeting these conditions is used to determine the supply capability of an area for the purpose of regional planning. Supply capability is expressed in terms of the maximum load that can be supplied in the local area with no interruptions in supply or, under certain permissible conditions, with limited controlled interruptions as specified by ORTAC.

Table B-1: ORTAC Supply Capacity Criteria for Systems with Local Generation

Pre-contingency		Contingency[1]	Thermal Rating	Maximum Permissible Load Rejection
All transmission elements in-service	Local generation in-service	N-0	Continuous	None
		N-1	LTE[2]	None
		N-2	LTE[2]	150 MW
	Local generation out-of-service	N- 0	Continuous	None
		N-1	LTE[2]	150 MW[3]
		N-2	LTE[2]	>150 MW[3] (600 MW total)

1. N-0 refers to all elements in-service; N-1 refers to one element (a circuit or transformer) out of service; N-2 refers to two elements out of service (for example, loss of two adjacent circuits on same tower, breaker failure or overlapping transformer outage),N-G refers to local generation not available (for example, out of service due to planned maintenance).
2. LTE: Long-term emergency rating. 50-hr rating for circuits, 10-day rating for transformers.
3. Only to account for the capacity of the local generating unit out of service

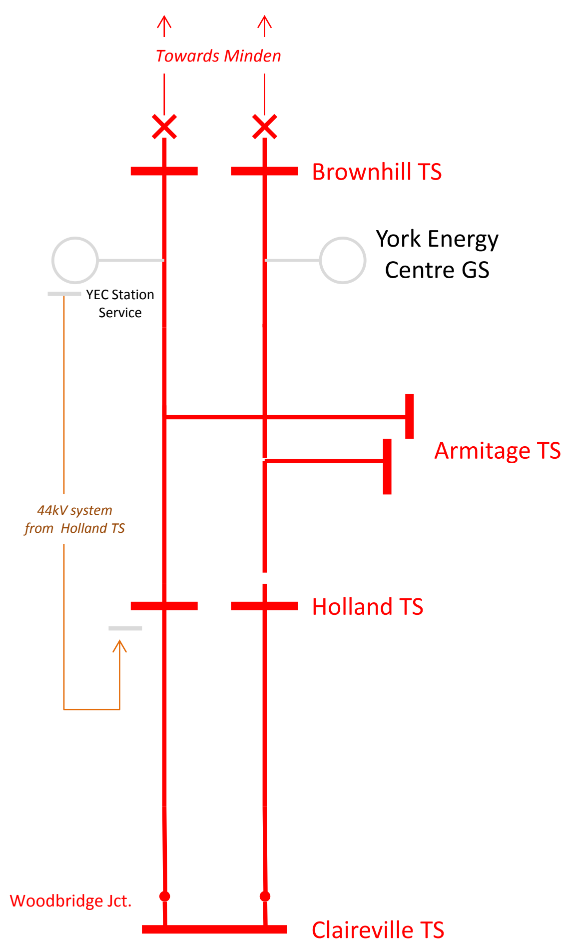
B.3.2 Existing System

The Claireville-to-Minden system, shown in Figure B-1, was assessed under applicable transmission and generation outage scenarios, and load security criteria, as defined by ORTAC. The Load Meeting Capability (LMC) of the system is defined by the most limiting contingency or criterion identified through this assessment.

The LMC of the existing Claireville-to-Minden system, which consists of the 230 kV double-circuit transmission line carrying the circuits B82V and B83V, as well as the local generation at York Energy Centre, is 600 MW. This is defined by the ORTAC load security criterion, which specifies that no more than 600 MW may be lost by configuration in a contingency involving two system elements. Currently, with no isolating devices on the system between Claireville and Brown Hill, this is the most limiting criterion on this system.

While not currently limiting, the supply capability of the system based on contingency analysis is only slightly higher than the load security limit. The next most limiting contingency is a thermal limitation on the section of B82V or B83V between Holland and Claireville following an outage involving the companion circuit. This contingency would limit the supply capability of the Clairieville-to-Minden system to 650 MW.

Figure B-1: Existing Claireville-to-Minden System Configuration

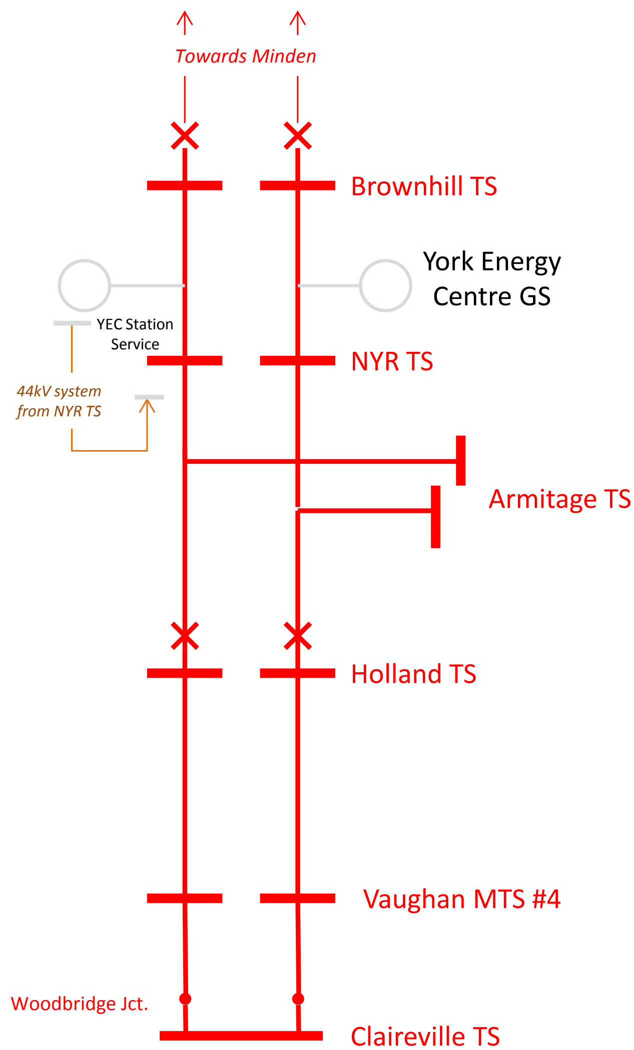


B.3.3 With Addition of In-Line Breakers at Holland TS

The installation of two in-line breakers at the Holland station site, along with motorized disconnect switches and a Load Reduction (L/R) scheme, is part of the recommended near-term plan for York Region (see Figure B-2). The in-line breakers will address the 600 MW load loss limit by sectionalizing the line. In combination with the L/R scheme, the breakers will also increase the supply capability of the system. The new LMC on the Claireville-to-Minden system with these enhancements will be 850 MW. The most limiting contingency defining this LMC is an outage on B82V between the Brown Hill and Holland stations while the YEC unit connected to B83V is unavailable. Under these conditions, the section of B83V north of the breakers would be thermally limited.

The station service supply arrangement for YEC has an impact on the capability of the Claireville-to-Minden system. Currently, its primary supply is through a 44 kV feeder originating at Holland TS. In determining the LMC described above, it was assumed that, as load growth in Northern York Region progresses to the point that a new station is required, the station would be connected north of the in-line breakers, and the station service supply for YEC would be reconnected to that station. If the YEC station service were to continue to be supplied from Holland TS the LMC of the Claireville-to-Minden system would be limited to approximately 700-750 MW.

Figure B-2: Claireville-to-Minden System Configuration after Addition of Holland Switching Facilities



York Region IRRP

Appendix C: Conservation

Appendix C: Conservation

This Appendix includes descriptions provided by the LDCs of their conservation plans, and describes efforts planned to assess conservation potential going forward. In addition to LDC programs, the Chippewas of Georgina Island First Nation have participated in the IESO's Aboriginal Conservation Program.

C.1 LDC Conservation Plans

The following summaries were provided by LDCs to introduce their CDM Plans for the years 2015-2020, required as part of the Conservation First Framework for 2015-2020. LDCs are required to submit their CDM Plans to the IESO by April 30, 2015. Additional details can be found on each LDC's respective website.

C.1.1 PowerStream

On December 18, 2014, PowerStream submitted its 2015-2020 CDM Plan to the IESO. The plan outlines how it will achieve the new conservation target of 535 GWh over 2015 to 2020.

The plan includes a comprehensive mix of conservation programs to be made available to various types of customers including residential, commercial and industrial customers. Many of the Province-Wide CDM programs designed and funded by the IESO under the 2011-2014 framework will continue to be available under the 2015-2020 framework. PowerStream anticipates that these existing provincial programs, along with some planned enhancements, will continue to contribute the majority of savings within the program portfolio. The plan also calls for new and innovative local programs to supplement the provincial programs.

The annual CDM savings forecast over 2015-2020 was developed at a program level based on inputs from several sources including: CDM achievable potential study conducted by the IESO, PowerStream's historical CDM results, market research, input from third party consultants and CDM management staff. The key steps in developing the CDM savings forecast were as follows:

Step 1 – Provincial Programs. Savings were forecast by estimating the annual participation levels (e.g. number of projects or participants) for each continuing Provincial Program and multiplying the participation forecast by the average savings per project achieved in the program historically.

Step 2 – Anticipated Enhancements to Provincial Programs. Energy savings for anticipated enhancements to the Provincial Programs during the 2015-2020 timeframe were developed based on a review of similar program design elements in other jurisdictions. Based on steps 1 and 2, PowerStream estimates that Provincial Programs (including planned enhancements) will contribute energy savings amounting to about 64% of its 6-year CDM target.

Step 3 – New Programs. In its CDM Plan submission to the IESO, PowerStream identified five concepts for new CDM programs. The detailed program design and business cases for these programs are yet to be developed and approved by the IESO. For the purposes of its CDM Plan, PowerStream made a high level estimate of potential energy savings based on a review of similar programs in other jurisdictions. The delivery costs for the programs were then estimated by multiplying the forecast energy savings by the 'budget rates' (i.e., $310/MWh for residential programs; $240/MWh for non-residential programs) used by the IESO in allocating PowerStream its overall CDM delivery budget of $140.7 million.

Step 4 – Shortfall. Based on all planned CDM programs (current provincial programs, planned enhancements to provincial programs, and new programs), PowerStream estimates achieving about 75% of its 2020 CDM target. In its CDM Plan, PowerStream has identified 131 GWh (25% of target) as a current shortfall. PowerStream plans to achieve 100% of its IESO-allocated target and will continue to explore and develop new program ideas for addressing this shortfall.

PowerStream's 2015-2020 conservation targets are being built into the development of the IRRP and RIP for GTA North, as well as PowerStream's Distribution System Plan. PowerStream is also actively supporting the City of Vaughan and the City of Markham with their Community Energy Plans, by providing data and by participating on advisory committees.

C.1.2 Newmarket-Tay Power

Conservation and demand management will play a significant role in meeting future load growth within York Region. Conservation and demand management targets established in the 2013 LTEP are a key component of the near-term plan for York Region. Based on the success and lessons learned from the initial 2011-2014 CDM framework, Newmarket-Tay Power Distribution is currently preparing a detailed CDM plan for the second CDM framework 2015-2020. Efforts will be focused as much as possible on measures that provide peak demand reduction.

Newmarket-Tay Power Distribution Ltd. will be an active participant in all provincial programs for residential, commercial and industrial sectors. Additional targeted efforts will be directed towards those programs that offer a higher degree of impact on demand reduction. Programs such as the Feed-in-Tariff, (FIT) Demand Response (DR) and Combined Heat and Power (CHP) are expected to have the largest impact towards achieving success. The potential evolution of existing microFIT program to a net metering program outlined in the Conservation First document may prove to be a mechanism to increase customer participation in this area of demand reduction. Newmarket-Tay Power Distribution is reviewing an opportunity to proceed with various pilots to increase customer participation in this area.

The provincial Conservation First policy provides a clear mandate to significantly increase the focus on conservation. Ontario's vision is to invest in conservation first, before new generation, where cost-effective.

As outlined in the Conservation First policy, CDM savings can be achieved in a range of ways:

- Energy efficiency: Using more energy efficient technology that consumes less electricity, such as LED lighting. Building codes and product efficiency standards help improve the energy efficiency of new buildings and appliances.
- Behavioural changes: Increasing awareness and encouraging different behaviour to reduce energy use, for example through social benchmarking.
- Demand management: Reducing or shifting consumption away from peak times, using time-of-use pricing with smart meters and programs like Peaksaver PLUS® and Demand Response 3.
- Load displacement: Reducing load on the grid by enabling customers to improve the efficiency of their energy systems by recovering waste heat or generating electricity required to meet their own needs.

To help meet its conservation goals under the new Conservation First framework in Ontario for 2015-2020, Newmarket-Tay has teamed up with other LDCs of similar size to create a company called CustomerFirst to assist with the design and delivery of conservation programs.

By working together, CustomerFirst member utilities will find efficiencies in the delivery of conservation programs and this will lead to cost savings for electricity customers. Through collaboration and sharing of resources and expertise, CustomerFirst will look for innovative conservation programs including programs designed specifically for the Newmarket-Tay region. With increased customer participation in cost-effective programs that are available to all customer types and sectors, Newmarket-Tay along with the other members of CustomerFirst will continue to put conservation first and realize conservation savings that will contribute to the supply plan for the York Region.

C.1.3 Hydro One Distribution

The Government of Ontario has identified CDM as the most cost-effective electricity supply option. Hydro One has been actively delivering CDM programs since 2005 and will look to build on its efforts over the years to provide its most comprehensive CDM offerings to date during the 2015-2020 Conservation First framework. While Hydro One will be working diligently towards achieving an ambitious 2020 energy savings target as part of the new Conservation First framework, it also recognizes the need and significance of delivering peak demand savings.

Hydro One will make CDM programs available to each of its customer segments, including low-income and First Nations customers. Hydro One is participating in a number of utility working groups developing enhancements to existing CDM programs. Once implemented, these program enhancements will help to drive both higher levels of participation and deeper savings opportunities for program participants. In addition to Province-Wide CDM programs, Hydro One also plans on developing local and regional CDM programs that will aim to help customers save on their bills and defer investments in its asset infrastructure.

As per the CDM Requirement Guidelines for Electricity Distributers released by the OEB on December 19, 2014,[4] Hydro One's distribution planning will incorporate its CDM plans at the outset of the planning process. Thus, distribution investments to increase the system capacity will only be implemented as the regional solution where CDM is not a viable option.

C.2 Conservation Potential

The IESO is currently undertaking an Achievable Potential Study to develop of an updated forecast for conservation potential in Ontario. The Study will be used to inform:

- the 2015-2020 Conservation First Framework mid-term review, including developing aggregate and LDC-specific achievable potential estimate in 2020;
- the short-term and long-term planning and program design; and

[4] CDM Requirement Guidelines for Electricity Distributors EB-2014-0278:
http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/CDM_Guidelines_Elec_Distributors_20141219.pdf

- the 2016 Long Term Energy Plan (LTEP), including developing 20-year provincial economic potential and achievable potential estimates.

The study is scheduled for to be completed by June 1, 2016. Local consumption and conservation potential information is expected to be collected, with finer granularity than has previously been available, through this study. For example, achievable potential will be estimated by sub-sector and end use for each LDC. With this information, the IESO and LDCs will be in a better position to address identified needs in York Region in the next iteration of the plan.

York Region IRRP

Appendix D: Development of Community Based Solutions

Appendix D: Development of Community Based Solutions

This Appendix includes sections provided by the LDCs describing their view on developing community-based solutions.

D.1 Newmarket-Tay and PowerStream

As outlined in foregoing sections of this report, York Region is one of the fastest growing areas in Ontario, and the GTA, with forecast electricity load growth of 2-3% annually over the next 20 years (600 MW). In the absence of offsetting load reduction initiatives the construction of substantial new generation, transmission and distribution supply infrastructure will be required.

Siting new electricity supply infrastructure has become a contentious and difficult exercise with various stakeholders citing concerns with regards to the transparency of the process and opportunities for input.

Moreover, identifying representative participants from different customer segments, developing their knowledge of integrated supply planning considerations, effectively incorporating their input, and completing the required work in time to meet growing electricity demand requirements is not without challenge.

In direct response to these concerns a new approach designated "Community Self-Sufficiency" has been developed. The goal of Community Self-Sufficiency is to address these challenges through the use of new forms of customer engagement, new technologies and imaginative new solutions – in effect "To create a next-generation Ontario Supply Model".

This initiative targets the Long-Term Supply Planning Horizon or, as it has been referred to, "2020 & Beyond" because of the time required to pioneer, test and implement new technological solutions.

Under the overarching approval authority of the IESO, Newmarket-Tay and PowerStream will lead the engagement efforts in our communities. We will play a key role in identifying members of the public to participate in Local Advisory Committees as well playing a critical integration & liaison role with closely related planning processes such as the Municipal Energy Plans.

Our objectives are to successfully meet customer demand and growth across York Region throughout the supply planning period:

- While addressing regional electricity infrastructure and business (employment) needs;
- While satisfying system optimization and cost management objectives consistent with the asset management strategies of the utilities: and
- While pioneering new technologies and solutions showcasing the strategic vision and direction of our utilities.

Our Plan at a Glance:

- Develop stakeholder engagement strategy
- Develop liaison strategy
- Identify promising technologies & solutions
- Recruit technology partners
- Recruit stakeholders
- Commission test bed facility
- Develop "Innovation Cluster"
- Incorporate proven solutions into utility asset plans.

The technology solutions are not limited to but will consider the following:

- Advanced fuel cell technologies
- Advanced storage technologies – particularly in combination with fuel cells
- Aggressive DR programs – particularly Residential and Small Commercial Demand Response programs enabled by Aggregators
- Aggressive Conservation programs targeted at Residential Consumers and enabled by next-generation Home Area Networks
- Battery Electric Vehicle storage capabilities, especially for load intensification cluster applications
- Enhanced Renewable Generation opportunities enabled by next-generation storage technologies
- Micro-Grid and Micro-Generation technologies coupled with next-generation storage technologies
- Combined Heat and Power (CHP) opportunities
- Renewed consideration of the Load Serving Entity/Aggregator market model.

There are significant risks associated with this strategy, the most crucial being the necessity to successfully meet the growth in electricity demand with new and unproven load management and storage technologies.

Other key risks include demonstrating consumer value, cost recovery certainty for innovative technologies and the associated risk of asset stranding, risk/reward incentives and technological obsolescence as a casual factor for asset replacement.

PowerStream's recently implemented micro-grid field trial offers a degree of risk mitigation as it does provide a means to evaluate and provide feedback on the feasibility, scalability and cost effectiveness for new and experimental technologies.

D.2 Hydro One Distribution

Hydro One is exploring a variety of program offerings that provide customer and electricity system benefits through energy efficiency, behavioural changes, load displacement, load shifting, demand response, and energy storage. Hydro One is willing to collaborate with local electricity utilities and gas utilities to develop programs and implement projects that will be cost-effective and benefit the greater electricity system.