PICKERING-AJAX-WHITBY SUB-REGION INTEGRATED REGIONAL RESOURCE PLAN - APPENDICES

Part of the GTA East Planning Region | June 30, 2016

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Pickering-Ajax-Whitby Sub-region IRRP

Appendix A: Demand Forecasts

Appendix A: Demand Forecasts

This Appendix provides details of the methodology used to develop the demand forecasts produced by the LDCs, as well as conservation and distributed generation assumptions, and detailed planning forecasts.

A.1 Gross Demand Forecasts

Appendices A.1.1 through A.1.2 describe the methodologies used by LDCs to prepare the gross demand forecasts used in this IRRP. Gross demand forecasts by station are provided in Appendix A.1.3.

A.1.1 Veridian Connections

Veridian Connections receives its power from Hydro One Networks Inc. (HONI) through two (2) transformer stations (TS), Whitby TS – DESN 1 & DESN 2 and Cherrywood TS in Pickering. Both stations are owned and operated by HONI. These transformer stations are connected to the provincial transmission system at 230 kV and deliver 44kV supply from Whitby DESN2, Cherrywood TS and 27.6kV supply from Whitby DESN1 for Veridian's use.

Veridian relies primarily on the relationship between population and typical load per customer type to generate its demand forecasts. Average load per customer type comes from analysis of Veridian's own customer data as well as incorporating the impacts of mandated CDM targets. This average load is also reviewed against changing trends in consumption to incorporate changes such as the charging of electric cars, or the penetration of DG with net metering.

Information on expected population changes typically comes from the Planning departments at the City of Pickering and the Town of Ajax. Additional information to help inform Veridian about future population growth may also come from the Region of Durham and/or developers/builders as well.

A.1.2 Whitby Hydro

Whitby Hydro receives its power from Hydro One Networks Inc (HONI) through two (2) transformer stations (TS), one located within the town's boundary (Whitby TS – DESN 1 & DESN 2) and one outside of the town's boundary (Thornton TS). All of these stations are owned and operated by HONI. These transformer stations are connected to the provincial transmission system at 230 kV and to Whitby Hydro's subtransmission system at 44 kV.

In general, the long term forecast relies on the historic relationship between electricity consumption and socio-economic indicators such as population growth.

Economic conditions, population growth and the availability of serviceable lands are the principle factors that influence load growth. Information used to forecast residential growth is collected from the following sources:

- The Town of Whitby's Planning Department

- Total number of vacant lots in existing developments
- Proposed subdivisions to be constructed
- Developers and/or builders
- Building permits issued by the Town of Whitby

The methodology for load forecasting is based on the history of feeder loads which are studied and correlated to population growth. The results are plotted and Linear Regression methods are used to establish a trend line. The trend line is then used to forecast future loads. Past trends are judged to assess if they will affect future expectations. Planning for a New TS should begin when loads exceed 80% of the 10-Day Limited Time Rating (LTR).

A.1.3 Gross Demand Forecast by TS

The following table shows the gross peak demand per station, as provided by LDCs. Where necessary, forecasts were extended until the end of the study period in 2034.

Table A-1: Gross Demand Forecast (MW)

Gross Demand	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cherrywood TS	180	180	180	180	180	180	180	180	180	176	176	176	176	176	176	176	176	176	176	176
Whitby TS DESN1	101	115	131	143	146	147	148	149	150	151	152	153	154	155	156	157	158	159	160	161
Whitby TS DESN2	172	178	180	185	187	189	190	192	194	196	198	199	201	203	205	207	209	211	213	215
Seaton TS (Proposed)	0	0	0	5	16	27	40	60	75	88	98	108	114	120	126	132	139	145	152	159

A.2 Conservation

The following tables show the expected peak demand impact of provincial energy targets, as assumed at each station for the purpose of the Planning forecast.

Table A-2: Conservation Assumptions by station (MW)

Conservation Savings	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cherrywood TS	1	2	3	5	7	8	10	11	12	13	15	16	17	17	18	19	20	19	19	19
Whitby TS DESN1	1	2	3	4	6	7	8	9	10	12	13	14	15	16	17	17	18	18	18	18
Whitby TS DESN2	1	2	3	5	6	8	9	11	13	15	17	18	20	21	22	23	24	24	24	24
Seaton TS (Proposed)	0	0	0	0	0	1	1	2	3	4	6	7	9	10	12	13	15	16	16	17

A.3 Distributed Generation

As of September 2014, the IESO (then OPA) had awarded 20 MW of distributed generation contracts within the Pickering-Ajax-Whitby Sub-Region. Of these, 1.5 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 that had not yet reached commercial operation when the forecasts were produced needed to be incorporated.

There were a total of 51 contracts signed for the Pickering-Ajax-Whitby Sub-Region, a majority for solar projects contracted through the Feed in Tariff (FIT) program. Contract information provided the installed capacity, generation fuel type, connecting station, and maximum commercial operation date (MCOD) for each project. It was assumed that all active contracts would be connected by their MCOD. The supply mix of DG contracts in the Sub-Region included solar and renewable biomass, as stated in table 5-2 of the IRRP, along with their respective capacity contributions.

For the IRRP, the IESO relied upon observed historical capacity contribution factors for renewable biomass and solar generation. Based on this methodology, summer peak capacity contributions of 34% and 98% were assumed for solar and renewable biomass, respectively. After considering the anticipated peak contribution of each contract, the total effective capacity for all active, unconnected DG contracts was estimated on a station by station basis. The final DG forecast is shown in Appendix A.3.1.

A.3.1 Distributed Generation Assumptions, by Station

The following table shows the expected peak demand impact of DG contracts by station by kW. All effective capacity before 2015 was assumed to be already working into the historical data. Only DG impacts in 2015 and later were added, cumulatively, to the planning forecast.

Station	Pre 2015	2015	2016
Whitby TS DESN 1	492	215	215
Whitby TS DESN 2	965	17,863	17,863

A.4 Planning Forecasts

The Planning forecast is the primary forecast for carrying out system studies and was based on gross demand forecasted by LDCs within their respective service territories. It was then adjusted by the IESO to account for the anticipated peak demand impacts of provincial conservation energy targets, and the effect of contracted DG. It represents the most likely outcome based on currently available information and initiatives, both local and provincial.

In the planning forecast, the final demand allocated to the Veridian Connections and Whitby Hydro stations were adjusted between adjacent stations to account for typical station loading and operating practices. This balancing practice ensured that a station already at full capacity would continue at full utilization, even if incremental peak demand-reducing measures (such as CDM and DG) would have produced a net decrease in the load. The IESO worked with Veridian Connections and Whitby Hydro to understand and implement these adjustments consistent with expected operation.

The final Planning forecast is provided in Appendix A.4.1.

A.4.1 lanning Forecast, by TS (MW)

Planning Forecast	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cherrywood TS	179	178	177	175	173	172	170	169	168	163	162	161	160	159	158	157	157	157	157	158
Whitby TS DESN1	100	113	128	138	141	140	140	140	140	139	139	138	138	139	139	139	139	140	142	143
Whitby TS DESN2	153	158	159	163	163	163	163	163	163	163	163	163	164	165	166	166	167	169	171	174
Seaton TS (Proposed)	0	0	0	5	15	26	38	58	72	84	92	101	105	110	114	119	124	129	135	142

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Appendix B: Transmission and Distribution Options for Meeting Near-Term Forecast Electrical Demand within the Pickering-Ajax-Whitby Sub-region

B.1 Purpose and Introduction

This document reviews the near-term need and timing for additional 27.6 kV transformation and feeder capacity required to serve growth in the Pickering-Ajax-Whitby Sub-region and identifies the technically and economically viable transmission and distribution options for meeting this need. This analysis was carried out as part of the Integrated Regional Resource Plan ("IRRP") for the Pickering-Ajax-Whitby Sub-region

The study process considered:

- The magnitude and location of growth in electrical demand within the IRRP study area
- The capability of existing transmission and distribution facilities to meet the growth in electrical demand within the area
- The technically feasible transmission and distribution options available for meeting forecast electrical demand
- The relative cost of the transmission and distribution options

The sub-region study area is outlined in the figure below and includes the service territory of Veridian Connections Inc. ("Veridian") and Whitby Hydro Electric Corporation ("Whitby Hydro"), with some customers in the area served by Hydro One Distribution as an embedded distributor within Veridian and Whitby Hydro facilities.

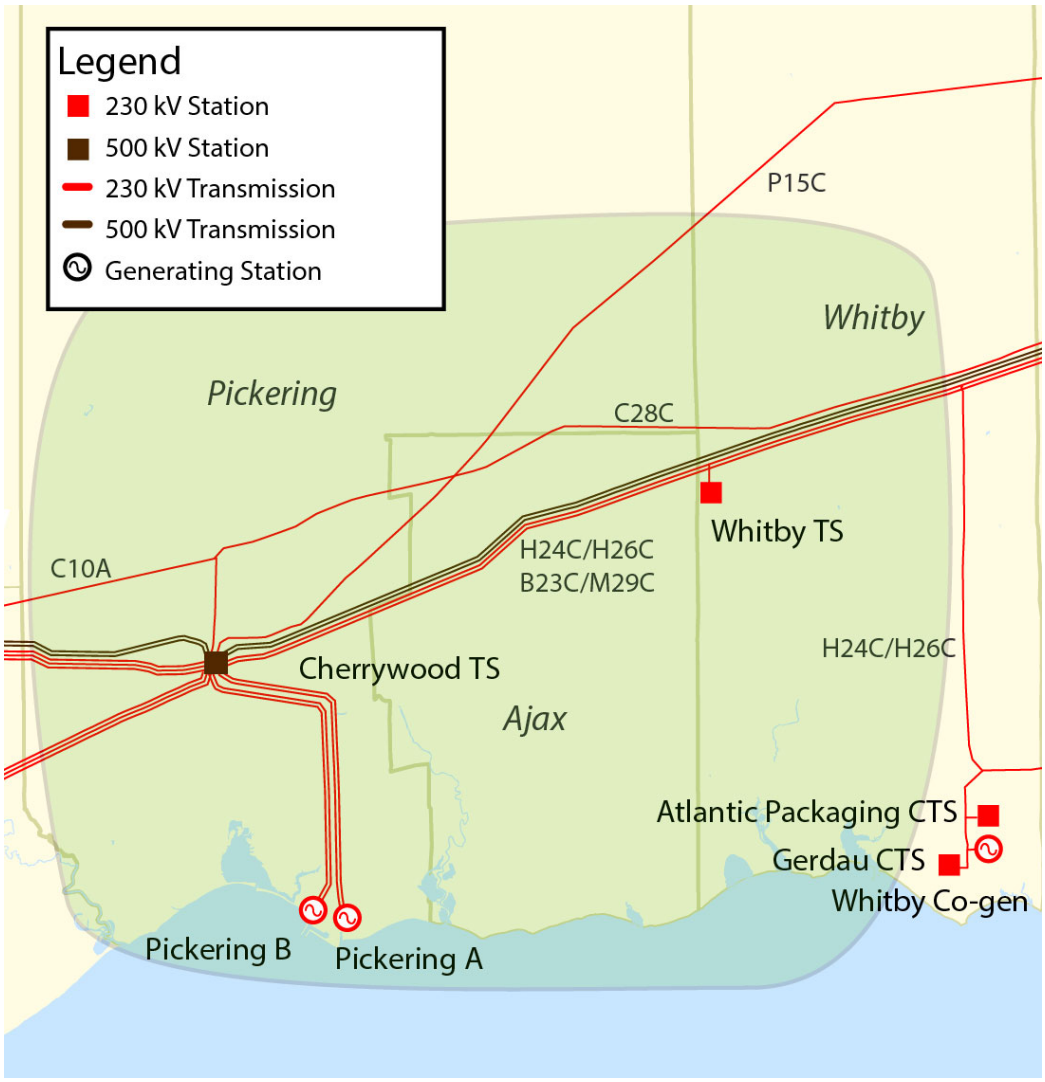

Figure 1 Pickering Ajax Whitby Study Area

Source: Data provided by Hydro One Networks Inc.

B.2 Area Supply

The main sources of transmission supply to this area are from Cherrywood TS and Whitby TS. These stations step down the voltage from 230 kV to either 44 kV or 27.6 kV distribution level voltages. The Cherrywood TS only steps down voltage to the 44 kV level, while Whitby TS steps voltage down to 27.6 kV and 44 kV levels. Only Veridian uses both voltage levels to supply its service territory, while Whitby Hydro provides distribution service at the 44 kV level. Dedicated feeders from Malvern TS and Sheppard TS also supply the western portion of

Veridian's service territory. These two stations are in the eastern part of another region-Metro Toronto.

B.3 Forecast Growth

Load forecasts used to perform this analysis were provided to the IESO by the three LDCs serving this area, Veridian, Whitby Hydro and Hydro One Distribution. The electrical demand impact of the energy based provincial conservation targets, which are outlined in the December 2013 LTEP, has been included in all planning forecasts. Uptake of DG through the FIT program and other projects has also been included. Additional information on the methodology used to prepare the net demand forecasts used in this study is available in appendix A of the IRRP.

Load growth within the overall study area is forecast to grow at an average annual rate of 2.1% over the 20-year study period, after accounting for the expected impact of provincial conservation targets and distributed generation.

- In the near term, Seaton-a greenfield development that is being planned in North Pickering with residential capacity for up to 70,000 people and 35,000 jobs, is influencing the strong growth rate mentioned above. Veridian plans to supply this community at 27.6 kV by the 2018 time period when significant development is expected to materialize. This area is currently not served by any transmission or distribution infrastructure, and is expected to fully utilize the capacity of a typical 230 / 27.6 kV step-down station over a 20-year time period.
- In the longer-term, growth is expected from the intensification and expansion of existing urban areas in downtown Pickering, Ajax, Whitby and targeted expansion of some areas such as the village of Brooklin in North Whitby. The growth targets for these municipalities are tied in part to the provincial growth targets for the Greater Golden Horseshoe and have been accounted for in the load forecasts provided by the LDCs.
- Given the nature of the near-term growth, 27.6 kV supply will be utilized leaving the remaining 44 kV capacity for serving the rural and industrial developments in the area. There is adequate 44 kV capacity to meet the growth needs of the area until the end of the study period.
- The highlighted area in Figure 2 shows the approximate geographic locations of the Seaton community relative to the local transmission infrastructure.

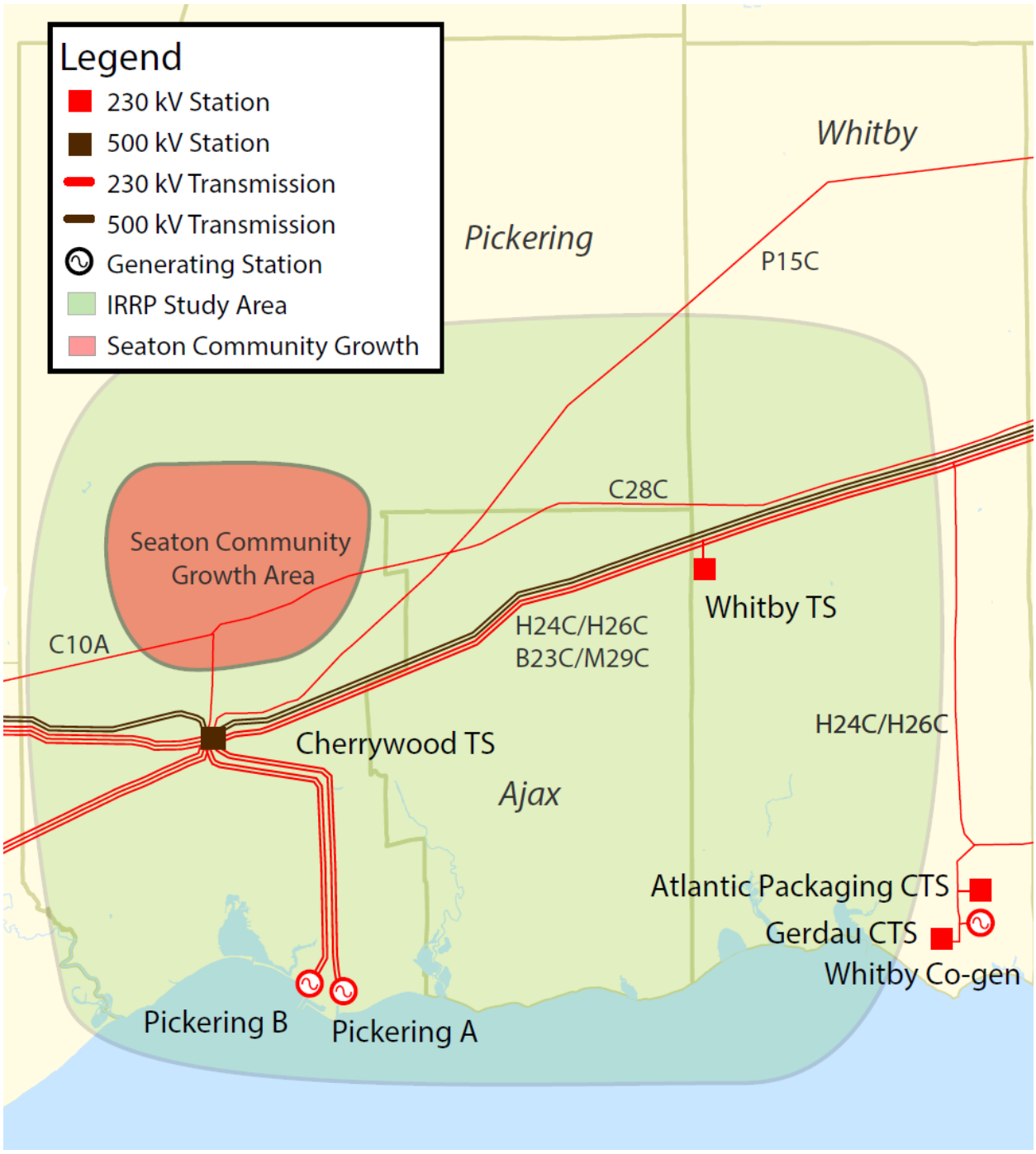

Figure 2 Growth Area

Source: Data provided by Hydro One Networks Inc.

B.4 Near Term Needs

Based on the planning forecast being used in this analysis, the capacity of the 230/27.6 kV transformers serving the sub-region is expected to be exceeded in 2019 (Figure 3). Sufficient 44 kV capacity exists in the study area to supply 44 kV demand until the end of the study period.

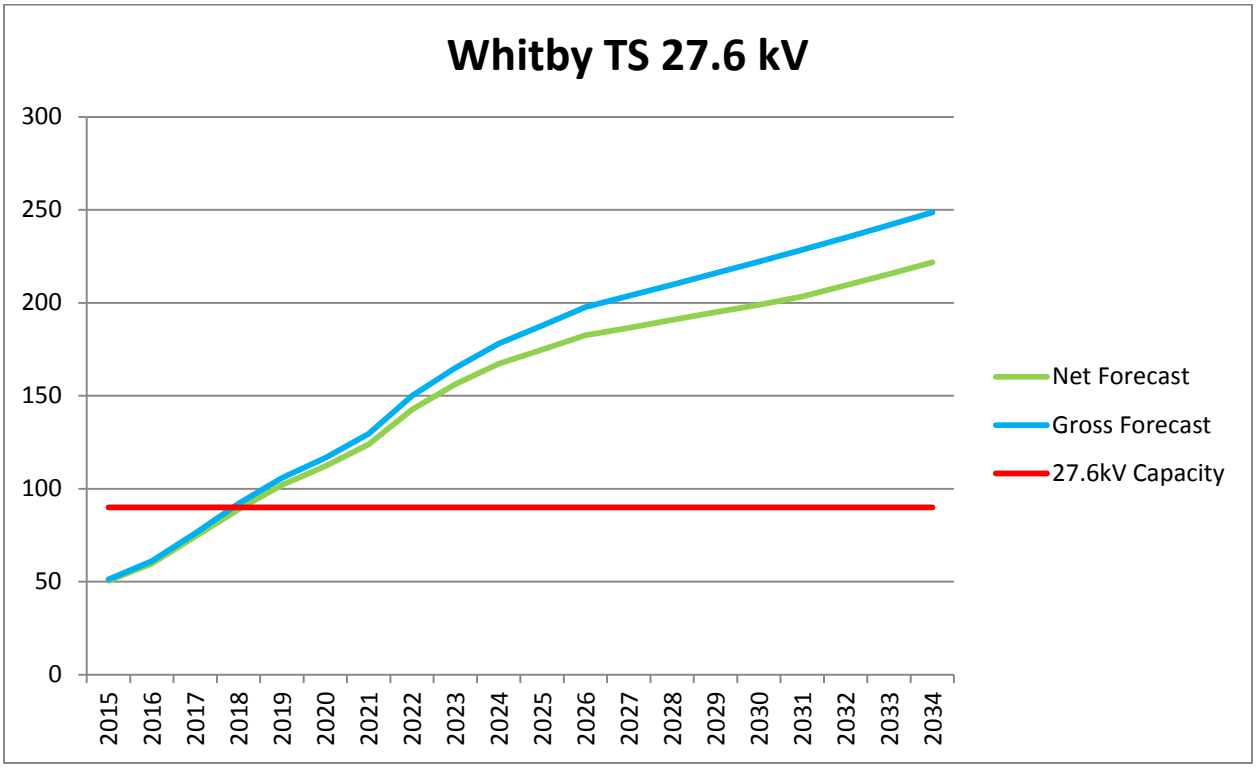

Figure 3 Whitby TS 27.6 kV Capacity

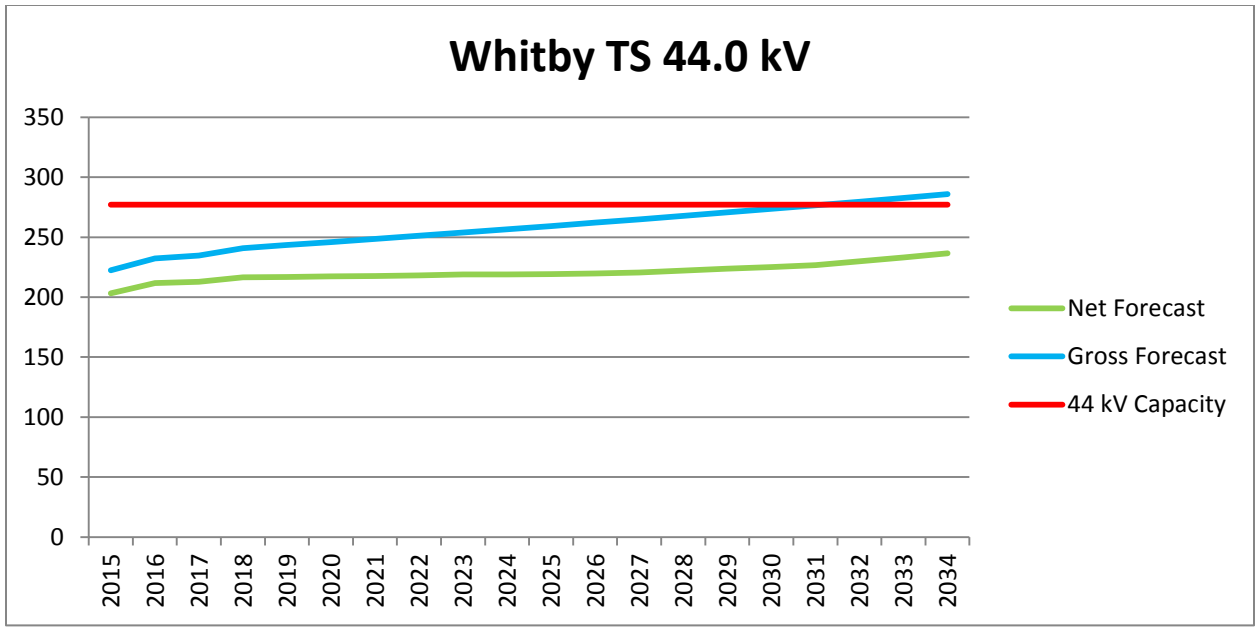

Figure 4 Whitby TS 44 kV Capacity

The 10 year forecast for 27.6 kV demand in the area is shown in the table below, with demand exceeding available capacity highlighted in red:

BY bus LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
90	51	60	74	89	102	112	124	143	156	167

Table 1 Whitby TS 27.6 kV loading and expected growth (MW) to 2024

Incremental 27.6 kV capacity of approximately 12 MW will be needed by 2019 increasing to approximately 132 MW by 2034 at the end of the study period. The majority of this 27.6 kV growth from 2018 onwards is due to the expected demand from the new community of Seaton. This community is forecast by 2034 to have a gross electricity demand of 160 MW, reduced to approximately 142 MW of demand after considering the impacts of conservation and DG.

Given the near-term nature of this need, this report provides a detailed planning analysis of the technically feasible transmission and/or distribution alternatives for meeting the area's 27.6 kV capacity shortfall.

The following sections analyze the technical and economic feasibility of transmission and distribution options in the sub-region. The options include building feeders from an existing step-down transformer station ("TS") having incremental capacity, the incorporation of new step-down stations, and combinations of these options.

B.5 Near-Term Supply Options

Provide additional 27.6 kV supply from existing Transformer Stations

Generally speaking, where technically and economically feasible, distribution transfers can be used on a short- or long-term basis to supply load growth from existing TSs that have available capacity. Currently, no incremental 27.6 kV capacity is available at the existing stations within the sub-region. However, two stations within the adjacent Metro Toronto Region-Sheppard and Malvern TS that already provides supply to Veridian customers are forecast to have incremental 27.6 kV transformation capacity available. Therefore new feeders from these existing stations were investigated as alternatives for providing the needed 27.6 kV capacity to the area.

Sheppard 230/27.6 kV TS:

Sheppard TS is a station in Metro Toronto that is already utilized by Veridian. Current estimates show that approximately 25 MW of 27.6 kV supply capacity is available at this station until the end of the study period. Geographically, this station is approximately 11 km west of the near-term growth area and it is technically feasible to supply the growth area from this station. This station is included in the economic analysis to meet the near-term need for additional 27.6 kV capacity in the study area.

Malvern TS 230/27.6 kV TS:

Malvern TS is a 230/27.6 kV station in Metro Toronto that is already utilized by Veridian. Current estimates show that approximately 60 MW of supply capacity is available at this station until the end of the study period. Geographically, this station is approximately 12 km south west of the near-term growth area and it is technically feasible to supply the growth area from this station. This station is included in the economic analysis to meet the near-term need for 27.6 kV capacity in the study area.

As both these stations only provide a portion (85 MW) of the total incremental 27.6 kV capacity (132 MW) that will be required by 2034, they will be considered as part of a staged wires based solution that can meet the entire capacity need.

Provide additional 27.6 kV supply from a new Transformer Station in the sub-region

New step-down station 230/27.6 kV:

Another option is to provide a new (75/125 MVA) 230/27.6 kV station in the vicinity of the growth area to meet the incremental 27.6 kV demand. Figure 5 shows the locations of the three station sites undergoing an Environmental Assessment. Sites 1 and 2 are the closest to the load centre while Site 3 is the furthest away. This analysis considers building feeders from Site 3 to the approximate load centre which for study purposes is assumed to be at Site 2 as it is closest to the load centre and feeders from other 27.6 kV supply stations, and closest to the transmission supply.

This option is included in the economic analysis to meet the near-term need for 27.6 kV capacity in the sub-region.

Figure 5 shows the relative locations of Sheppard TS and Malvern TS to the new growth area in North Pickering and the prospective sites for a new station within the community of Seaton (outlined in pink).

Figure 5 Locations of Alternative Sources of 27.6 kV Supply

Source: Data provided by Hydro One Networks Inc.

B.6 Transmission and Distribution Infrastructure Alternatives

Eight potential supply alternatives were developed for providing the capacity needed to meet the near-term growth in the area and are summarized in the table below. These alternatives were a combination of the feeder and station options presented in the previous section. The years that assets will need to be in service in order to serve the load for each alternative are also shown in Table 2 below:

Alternatives	Alternative Details and Need Date
1. Use Malvern TS capacity and build Seaton TS-1 or 2	-Build Feeders 1&2 (2019) -Build Feeders 3&4 (2021) -Build Seaton TS (2023)
2. Use Malvern TS capacity and build Seaton TS-3 and associated feeders	-Build Feeders 1&2 (2019) -Build Feeders 3&4 (2021) -Build Seaton TS and Feeders 1&2 (2023) -Build Feeders 3&4 (2026) -Build Feeders 5&6 (2033)
3. Use Sheppard TS capacity and build Seaton TS-1 or 2	-Build Feeders 1&2 (2019) -Build Seaton TS (2021)
4. Use Sheppard TS capacity and build Seaton TS-3 and associated feeders	-Build Feeders 1&2 (2019) -Build Seaton TS and Feeders 1&2 (2021) -Build Feeders 3&4 (2023) -Build Feeders 5&6 (2025) -Build Feeders 7&8 (2032)
5. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-1	-Build Feeders 1&2 (2019) -Build Feeders 1&2 (2021)

or 2	-Build Feeders 3&4 (2023) -Build Seaton TS (2026)
6. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-3 and associated feeders	-Build Feeders 1&2 (2019) -Build Feeders 1&2 (2021) -Build Feeders 3&4 (2023) -Build Seaton TS and Feeders 1&2 (2026) -Feeders 3&4 (2032)
7. Build Seaton TS- 1 or 2	-Build Seaton TS (2019)
. Build Seaton TS-3 and associated feeders to load ar	-Build Seaton TS and Feeders 1&2 (2019) -Build Feeders 3&4 (2021) -Build Feeders 5&6 (2023) -Build Feeders 7&8 (2026) -Build Feeders 9&10 (2033)

Table 2 Alternatives and need dates

Additional Details:

- A forecast net of conservation and distributed generation has been used in order to determine magnitude and timing of need.
- Two feeders will be built when a capacity need is triggered.
- Feeders are assumed to provide a maximum of 15.5 MW capacity.
- Feeders from Malvern TS will follow transmission right of way until Whites Rd, and then run North on Whites Rd, and East on to Taunton Rd to the load centre.
- Feeder losses were calculated using typical 27.6 kV conductor specifications.
- Planning level feeder construction and station costs were provided by Veridian.

- Planning level transmission line costs were provided by Hydro One Networks Inc.

B.7 Economic Comparison of Alternatives

To compare alternatives based on cost to the ratepayer[1], an economic assessment was performed. The evaluation present valued costs to 2016, considering a 45-year study period – 2019 to 2063 (based on the first replacement decision across all six alternatives; transmission station assets assume a 45-year life). Table 3 and Table 4 summarize the main cost assumptions considered in the evaluation of each alternative (planning level estimates in 2014$ Canadian). All investments were converted to a real annual levelized cost (including on-going annual costs), spread across the asset's assumed life, and only levelized costs falling within the study period were considered. This approach credits value to assets whose life ends beyond the study period (terminal value credit). Table 5 summarizes the net present value results of the six alternatives (in 2016$ Canadian).

The tables below summarize the major economic assumptions used for this analysis:

Cost Breakdown	Malvern TS ($M)	Sheppard TS ($M)
Breaker position at TS	2	2
Feeders to overhead risers	0.4	0.4
Double circuit 28 kV wood pole construction ($0.2M/km) [2]	2.47-2.85	2.26-2.65
Cost adder-off road construction	0.40-0.80	0.40-0.80

[1] Ratepayer Perspective is defined as the viewpoint of the end-use electricity consumer. It includes residential, commercial, and industrial customers within Ontario, and in terms of economics, ratepayer perspective includes costs that flow to bills for their consumption of electricity.

[2] Costs are per pair of feeders-Veridian's deck dated July 2014

Engineering (10% of construction cost)	0.53-0.61	0.51-0.58
Contingency 10%-25%	0.58-1.66	0.56-1.61
Annual Feeder losses	0.36-0.42	0.22-0.25
TOTAL[3] [4] ($M)	**6.37-8.32**	**6.13-8.04**

Table 3 Capital and On-Going Annual Costs for Malvern and Sheppard TS

[3] Total Feeder costs in table above excludes Feeder losses, those are NPV'd separately and added to the feeder costs in the Results section

[4] The total cost shown is dependent on the contingency percentage, off –road construction cost adder and the distances to sites 1 and 2.

Cost Breakdown	Build Seaton TS – Site 1 ($M)	Build Seaton TS – Site 2 ($M)	Build Seaton TS-Site 3 ($M)	Build Feeders to Site 2 from Site 3 ($M) [5]
Feeders to overhead risers	2.40	2.40	2.40	n/a
Double circuit 28 kV wood pole construction ($0.2M/km)	n/a			6.46
Engineering (10% of construction costs)	n/a			0.65
Contingency costs	Included in cost of station			0.71-1.78
Connecting preferred station Site to the transmission system[6]	15	10	8	n/a
Annual	n/a			0.19

[5] Used the same feeder costs as provided by Veridian's consultant excluding off-road construction costs
[6] Transmission connection costs from Sites 1&2 Hydro One December 2015; connection cost for Site 1 from Veridian

feeder losses				
Build 230/28 kV station 170 MVA[7]	25.56			n/a
TOTAL	**42.96**	**37.96**	**35.96**	**8.01-9.09**

Table 4 Capital and On-Going Annual Costs for Seaton TS Sites

Alternative 1, Malvern TS Feeders 1&2 (2019) + Malvern TS Feeders 3&4 (2021) + Seaton TS 1 or 2 and associated 230 kV line (2023):

This alternative considers building a pair of feeders from Malvern TS to be in service for 2019, followed by the second pair in service for 2021. These four feeders will provide a collective capacity of 60 MW. Additional capacity will be needed in 2023 and will be provided by Seaton TS, built at Sites 1 or 2.

Alternative 2, Malvern TS Feeders 1&2 (2019) + Malvern TS Feeders 3&4 (2021) + Seaton TS 3 and associated 230 kV line and Feeders 1&2 (2023) +Feeders 3&4 (2026) +Feeders 5&6 (2033):

This alternative considers building a pair of feeders from Malvern TS to be in service for 2019, followed by the second pair in service for 2021. These four feeders will provide a collective capacity of 60 MW. Additional capacity will be needed in 2023 and will be provided by Seaton TS, built at Site 3 and the associated 230 kV supply line and 6 feeders to the load centre over the study period with a pair being built every time a capacity need is triggered.

Alternative 3, Sheppard TS Feeders 1&2 (2019) + Seaton TS 1 or 2 and associated 230 kV line (2021)

This alternative considers building a pair of feeders from Sheppard TS to be in service for 2019, providing a total capacity of 25 MW. Additional capacity will be needed in 2021 and will be provided by Seaton TS, to be built at Sites 1 or 2.

[7] Station costs from Veridian-November 2015

Alternative 4, Sheppard TS Feeders 1&2 (2019) + Seaton TS 3 and associated 230 kV line and Feeders 1&2 (2021) +Feeders 3&4 (2023) + Feeders 5&6 (2025) + Feeders 7&8 (2032)

This alternative considers building a pair of feeders from Sheppard to be in service for 2019, providing a total capacity of 25 MW. Additional capacity will be needed in 2021 and will be provided by Seaton TS, built at Site 3 and the associated 230 kV supply line and 8 feeders to the load centre over the study period with a pair being built every time a capacity need is triggered.

Alternative 5, Sheppard TS Feeders 1&2 (2019) + Malvern TS Feeders 1&2 (2021) + Feeders 3&4 (2023) + Seaton TS 1 or 2 and associated 230 kV line (2026)

Alternative 5 considers utilizing the entire surplus 26.6 kV capacity that is available at Sheppard TS and Malvern TS and meeting the remaining capacity need with a new station at either Sites 1 or 2.

Alternative 6, Sheppard TS Feeders 1&2 (2019) + Malvern TS Feeders 1&2 (2021) + Feeders 3&4 (2023) + Seaton TS 3 and associated 230 kV ine and Feeders 1&2 (2026) + Feeders 3&4 (2032)

Alternative 6 considers utilizing the entire surplus 26.6 kV capacity that is available at Sheppard TS and Malvern TS and meeting the remaining capacity need with a new station at either Sites 3 and associated feeders to the load centre.

Alternative 7, Seaton TS Site 1 or 2 associated 230 kV supply line (2019)

This alternative considers building a new station near the load centre at Sites 1 or 2 in 2019 when incremental 27.6 kV transformation and distribution capacity is needed in the area.

Alternative 8, Seaton TS at Site 3 and associated 230 kV supply line +Feeders 1&2 (2019)+Feeders 3&4 (2021) + Feeders 5&6 (2023) + Feeders 7&8 (2026) +Feeders 9&10 (2033)

This alternative considers building the new station at Site 3, the associated 230 kV supply line and 10 feeders to the load centre with a pair being built every time a capacity need is triggered. Additionally 8 of these feeders are assumed to be above ground (4 on each side of a road), while the remaining 2 will be underground.

The table below summarizes the total costs for each alternative:

Table 5 Net Present Value Range for Seaton Alternatives

Alternatives	2016 $M
1. Use Malvern TS capacity and then build Seaton TS at Site 1 or 2	93-109
2. Use Malvern TS capacity and build Seaton TS as Site 3 and associated feeders	104-119
3. Use Sheppard TS capacity and then build Seaton TS-1 or 2	73-84
4. Use Sheppard TS capacity and then build Seaton TS-3 and associated feeders	91-102
5. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-1 or 2	105-124
6. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-3 and associated feeders	113-130
7. Build Seaton TS-1 or 2	60-68
8. Build Seaton TS-3 and associated feeders	94-108

The results in Table 5 demonstrate that the most economic alternative for providing near-term 27.6 kV capacity to the area is to build a new 75 /125 MVA- 230 / 27.6 kV TS at Sites 1 or 2, to be in service for 2019. A new TS near the load centre would result in highest relative reliability

given the much shorter feeder distances. Additionally, this option also avoids the approval challenges of building several distribution feeders through a national park-Rouge Valley Urban National Park.

Should Site 3 be selected through the EA process, more detailed technical and economic analysis[8] is required to determine if a new station should be built only versus building feeders from the Malvern or Sheppard stations followed by a new station.

B.8 Conclusion

A new 75 /125 MVA- 230 / 27.6 kV TS at Sites 1 or 2, connected to transmission line C28C[9] to be in service for 2019, is the most cost-effective option to meet the need for additional 27.6 kV capacity in the sub-region.

The analysis was conducted assuming a 2019 in service date. However, given the uncertainty associated with the load forecast, which depends on fully meeting local conservation targets, working group members believe that it is prudent to target a 2018 in service date for the new step-down station. As part of implementation Veridian will monitor growth and adjust the station in-service date accordingly.

[8] Further analysis is recommended due to the similar range of costs of the two alternatives-Station at Site 3 or Building feeders from existing stations followed by a station at Site 3

[9] Currently C28C is a 230 kV single circuit and would need to be modified to 230 kV double circuit for a limited amount of length in order to connect the new station to the power system

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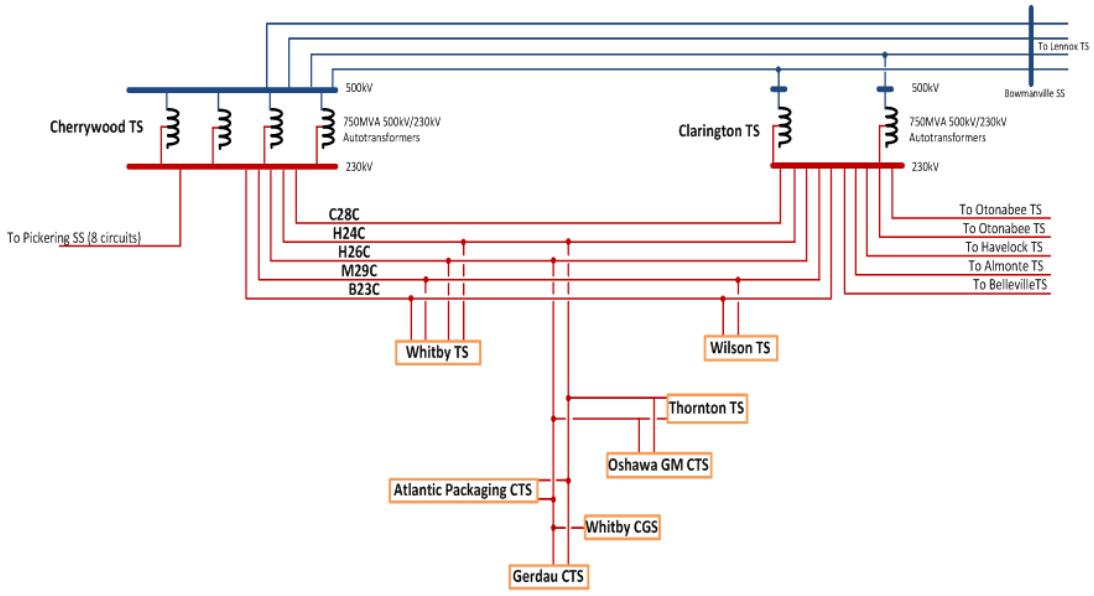
Appendix C: Analysis of Alternatives to Address Regional Restoration Need

Options to Address GTA East Restoration Needs

GTA East Region is served by four 230 kV circuits that emanate from Cherrywood TS and run eastwards towards Ottawa for 120-300 km[1]. These circuits supply Whitby TS, Wilson TS and a pair of these circuits is tapped by a radial line section which runs south to provide supply to Thornton TS and a number of direct connect customers. Figure 1 below shows these circuits and related points of supply. Once Clarington TS is in service in 2018, the region will be served by a new high capacity 230 kV supply point (connected to the 500 kV system) on the eastern end of the regional area. This new supply point will significantly reduce the length of the lines supplying this regional area (from hundreds of kilometers to less than 30) thereby improving supply reliability.

Figure 1-Single Line Diagram of the GTA East Region



The four circuits supplying this area are supported by a common tower line. The supply to customers however is split between the pairs of circuits. H24/26C supply Whitby TS DESN 1, Thornton TS and direct customers in the Whitby pocket; while M29/B23C supply Whitby

[1] Individual circuits terminate at different distances

DESN2 and Wilson TS. Together, these four circuits supplied approximately 792 MW of electrical demand during 2015 summer peak

The areas supplied by these circuits have been identified as not meeting ORTAC restoration load levels and timelines in the GTA East Region, as summarized in Table 6.2 of the IRRP. Transmission outages within the GTA are typically of short duration, due to the proximity of repair crews. A typical outage of this nature will be expected to be restored within 4 to 8 hours. Consequently the analysis only considers the area's ability to meet 30 minute and 4 hour restoration timelines.

Restoration capability is assessed assuming two simultaneous and prolonged outages occur on the transmission system. Restoration is achieved by isolating the faulted elements and restoring customers through supply sources which have electrical continuity. These supply sources could be at the transmission level, distribution level, or a combination of both. The customer demand or load levels that require restoration are specified in ORTAC Section 7.2.2. According to ORTAC[2], where a restoration need is identified, "transmission customers and transmitters can consider each case separately taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost". These affected customers and transmitters may agree on higher or lower levels of reliability for technical, economic, safety and environmental reasons. For this sub-region, a high level assessment of cost justification was undertaken to establish if more detailed analysis is warranted. Some jurisdictions assess cost justification for low probability / high impact events by comparing the cost risk (i.e., the probability of an event occurring and the consequences if it does) of the failure event to the cost of mitigating the risk. This is accomplished by:

1. Assessing the probability of the failure event occurring
2. Estimating the expected magnitude and duration of outages to customers served by the supply lines
3. Monetizing the cost of supply interruptions to the affected customer
4. Determining the cost of mitigating solutions and their impact on supply interruptions to the affect customers.

If the customer cost impact associated with the mitigating solutions exceeds the cost of customer supply interruptions under the status quo, the mitigating solutions are not considered cost justified.

[2] ORTAC Section 7.4 Application of Restoration Criteria <copy> or link pdf

This IESO applied this methodology to facilities serving transmission customers in GTA East.

First, the extent of the existing risk was quantified based on the supply line and load characteristics. The assessment was conducted with Clarington TS in service as it is scheduled to be in service for 2018. The inclusion of the new TS significantly shortens the circuits' lengths to approximately 30 km, and as a result the related reliability indices for annual frequency and duration are theoretically expected to significantly improve from current levels.

Based on a typical outage rate for double circuit lines in southern Ontario of 0.19/km/yr (calculated from historical outage rates for N-2 and N-1-1 type contingencies), and the length of the H24/26C and M29/B23C circuits (27 km with Clarington TS in service), the coincident outage rate is estimated to be approximately 1 outage every 20 years[3]. Although the present analysis has used average outage data from Southwestern Ontario, outage data for double circuits on common towers for the eastern portion of the GTA would further refine the current analysis.

The Table below shows the current demand served from these pairs of circuits and the increase in electrical demand expected to be served from these circuits in the next 10 years.

Load Pocket	2015 Actual Peak	2025 Net Forecast
H24/26C: Whitby TS DESN1, Thornton TS, Direct Connect Customers	356	567
M29/B23C: Whitby TS DESN2, Wilson TS	436	504

Following a double circuit outage on either circuit pair, area LDCs have the ability on a temporary emergency basis to transfer some amount of load to unaffected stations through the distribution system. The actual amount of transfer capability at a given moment would depend on several factors, including the operating condition at the time of the outage, and how the

[3] Historically, the H24/26C and M29/B23C circuits have sustained only one outage in 2008 which lasted for two hours. The cause was human error with regards to the protective settings on the B23C/M29C circuits; there has been no outage occurrence on the H24/26C circuits in the past 15 years.

distribution network is configured when the failure event occurs. In order to develop a conservative estimate of future restoration capability, the current restoration capabilities were assumed to remain constant. Table 1 shows the restoration shortfalls in MW for the 2015 recorded actual peak and 2025 planning forecast for the 30 minute and 4 hour timelines after taking into account area LDCs load transfer capabilities after a double circuit outage.

Table 1: Restoration Shortfall in MW for 2015 Peak and 2025 Planning Forecast

Load Pocket	2015 Peak					2025 Planning Forecast				
	Actual Demand	**30-Min Restoration**	**30-Min Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**	**Forecast**	**30 min Restoration**	**30-minute Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**
H24/H26: Whitby TS DESN1, Thornton TS, Direct Connect Customers	356	57	49	142	64	567	57	259	142	275
M29/B23: Whitby TS DESN2, Wilson TS	436	105	81	257	29	504	105	149	257	97

Going forward this analysis considers the two new step-down stations that have been recommended for this Regional area. A new step-down station in the proximity of Seaton is recommended as part of this IRRP for 2018, while the implementation of another station is underway in Clarington, which was recommended as part of the Oshawa-Clarington local planning report. The table below assumes that these stations will be in service and consequently any electrical demand forecast above current station limits is assumed to be transferred to one of the new stations. Any 27.6 kV electrical demand that exceeds Whitby TS LTR is assumed to be transferred to Seaton MTS, while any of the 44 kV demand that exceeds Wilson TS and Thornton TS combined LTR is assumed to be served by the new TS in Clarington. These assumptions are consistent with area LDC plans once the stations come into service.

Table 2: Restoration Shortfall in MW with the two new TSs in service

Load Pocket	2015 Peak					2025 Net				
	Actual Demand	30-Min Restoration	30-Min Restoration Shortfall	4-Hour Restoration	4-Hour Restoration Shortfall	Forecast	30 min Restoration	30-minute Restoration Shortfall	4-Hour Restoration	4-Hour Restoration Shortfall
H24/H26: Including Transmission Connected Customers	356	57	49	142	64	453	57	146	142	161
M29/B23: Whitby TS DESN2, Wilson TS	436	105	81	257	29	463	105	108	257	56

In order to consider the worst case scenario from a customer risk perspective, it is assumed that an H24/26C outage would interrupt the maximum 356 MW of load; and an M29/B23C outage would interrupt the maximum 436 MW of load. Assuming this event occurs at a rate of 0.05016 times per year, and lasts for 4 to 8 hours, this contingency represents a maximum of around 79.1 – 125.0 MWh of customer load at risk per year for H24C/H26C, and 89.3 – 160.1 MWh of customer load at risk for the M29C/B23C load pocket.

In order to quantify the cost risk of unserved energy, value of lost load ("VOLL"), represented in $/unserved energy, is used. Different jurisdictions have proposed a wide range of possible values, based on factors such of the type of customer, duration of outage, approximate loss of GDP, and estimated economic consequences of historical blackouts.

A 2013 briefing paper prepared by London Economics International LLC for the Electric Reliability Council of Texas carried out an international literature review of VOLL studies. The executive summary noted:

Average VOLLs for a developed, industrial economy range from approximately [US]$9,000/MWh to [US]$45,000/MWh. Looking on a more disaggregated level, residential customers generally have a lower VOLL ([US]$0/MWh - [US]$17,976/MWh) than commercial and industrial ("C/I") customers (whose VOLLs range from about [US]$3,000/MWH to [US]$53,907/MWh)[4].

Assuming equal parts residential and commercial/industrial load within the GTA East Region, this would suggest that the VOLL could range anywhere from $1.50/kWh to $35.94/kWh. While

[4]http://www.puc.texas.gov/industry/projects/electric/40000/40000_427_061813_ERCOT_VOLL_Literature_Review_and_Macroeconomic_Analysis.pdf

this represents a large range, it is consistent with a 2006 Canadian example of VOLL that was used in a regulatory application to upgrade the Cathedral Square Substation in downtown Vancouver. In a supporting paper released by BCTC, a low and high value for VOLL was estimated to be $3.07/kWh and $35.57/kWh, after considering customer composition and provincial GDP[5].

A VOLL range of $10- $30/ kWh is used in this analysis to provide a low and high estimate of the risk borne by local customers.

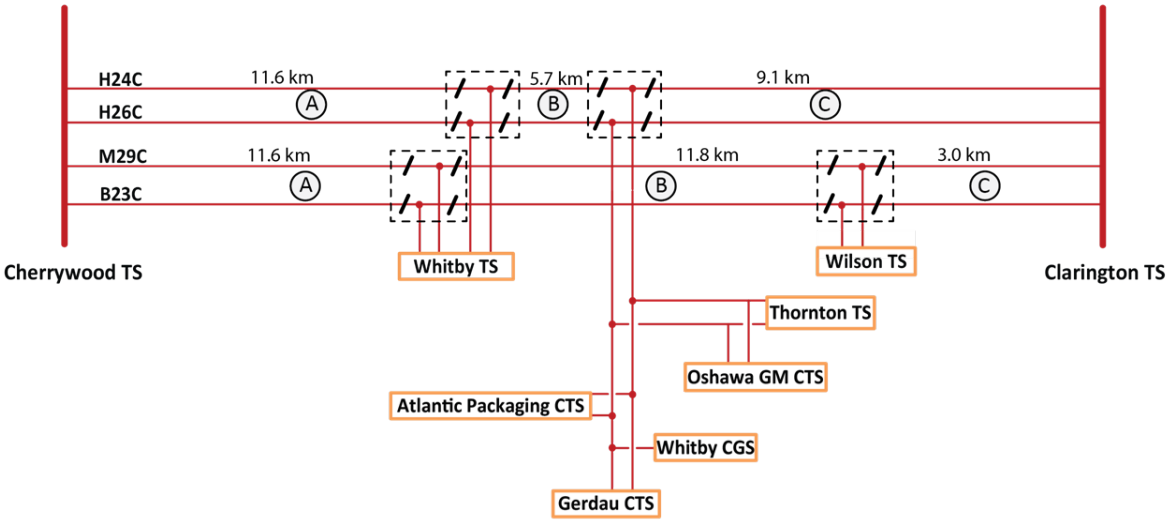
Using a VOLL of $10-30/kWh and assuming all load is restored within 4 hours, the equivalent economic risk by the 58.6 – 89.3 MWh/yr regional restoration vulnerability is approximately $586,000 – $2,680,000/yr. This roughly translates to a maximum present day risk of approximately $8 – $36 million over the 20 year planning horizon of this study.[6] From the VOLL calculations, it is reasonable to assume that there could be a benefit of between $8-23 million and $12-36 million to restore customer load along the H24C/H26C and M23C/B23C lines respectively for a wires solution; in other words it could be cost justified to implement a solution up to these monetary amounts.

Distribution level solutions, transmission level solutions or a combination of both could therefore be technically and economically feasible options to providing alternative sources of supply to loads during a rare double element outage up to the amounts specified above. A distribution solution for the GTA East Region could include the construction of additional load transfer capability between stations at the feeder level. The costs and technical feasibility of this type of solution however needs to be investigated further.

A transmission-based restoration solution for the GTA East Region would require the installation of motorized disconnect switches on the circuits. These disconnect switches enable operators to segregate faulted line sections and restore service to customers via an alternate supply source. The figure below shows the maximum number of switches (8 pairs) that could be utilized to account for the full complement of outages. The estimated cost of installing motorized switches is $5-6 million per circuit pair for a total capital cost of $40-48 million to account for all outages along the corridor.

[5] http://transmission.bchydro.com/nr/rdonlyres/86da00e7-105f-4f72-8d3c-342c06919b8e/0/oorareliabilityassessmentofcathedralsquaresubstation.pdf

[6] Present value of annual risk, over 29 years, 4% interest rate



This preliminary analysis indicates that there may be economic justification for proceeding with mitigating solutions in the area. More detailed analysis is required to be conducted by the transmitter and LDCs in the area. This analysis should account for detailed local outage statistics, refined solutions and cost assumptions.

Note that 8 pairs of switches is a very conservative estimate and further analysis is needed to determine the optimum number and location to substantially meet restoration load levels and timelines. The inclusion of switches or other wires based solutions on the regional transmission system adds another element of complexity that could negatively impact reliability; this also needs to be considered when conducting a detailed comparison of options for restoration. The risk to reliability is especially important as there are large industrial customers connected directly to the grid in this area and these types of customers typically have the highest impacts during these failure events. In order to justify any investment to meet the restoration timelines, assumptions should be refined to include the following:

- The amount of load at risk for interruption should be calculated based on typical load duration curves, instead of assuming the annual peak demand is maintained throughout the duration of an outage.
- Actual customer composition should be used to estimate VOLL (or a range of VOLLs) specific to the area.

Detailed study is also needed to determine the optimum number and location of switches, the inherent increase in risk introduced by the switches and other LDC operational benefits

provided by distribution level transfers. It is recommended that this detailed study be conducted as part of the Hydro One led RIP for the GTA East Region. This RIP is expected to be completed in Q1 2017 and will include all regional participants as working group members.

Pickering-Ajax-Whitby Sub-region IRRP

Appendix D: GTA East LAC Meeting Summaries

Meeting Information	
Date:	Thursday, March 10, 2016
Location:	Ajax, ON
Subject:	GTA East Local Advisory Committee Meeting #1
Attendees:	**Committee Members in Attendance** Ed Belsey Gilbert Boehm Jeff Brooks Meagan Craven Gabe Czegledy Adam Murree Dorothy Skinner Ralph Sutton Dr. Anita Tucker René C. Viau **Hydro One Distribution** Dhaval Patel **Hydro One Transmission** Ajay Garg **IESO** Joe Toneguzzo Wajiha Shoaib Luisa Da Rocha **Veridian Connections** Craig Smith Ed Johnston **Whitby Hydro** Rui Victal **Oshawa PUC** Ivano Labricciosa Jayesh Shah Eric Andres Rajendra Patel
LAC Meeting Materials:	http://www.ieso.ca/Pages/Participate/Regional-Planning/GTA-East/GTA-East.aspx

	Key Topics	Follow up Actions
1	**Opening Remarks and Roundtable Introductions** • Mr. Toneguzzo and Ms. Da Rocha welcomed everyone and discussed the meeting focus • Roundtable introductions were made	
2	**Role of LAC and Review of LAC Manual** • Ms. Da Rocha provided an overview of the Local Advisory Committee's role and the nature of issues and topics that the LAC will be discussing. It was indicated that the	

	focus of this LAC is on providing input on community preferences towards approaches for meeting mid and longer-term electrical growth. The solutions focused on the near-terms needs are already underway. The Integrated Regional Resource Plan for the Pickering-Ajax-Whitby sub-region will be posted in June 2016. **Review of LAC Manual** • The contents of the LAC manual were reviewed.	
2	**Presentation and Discussion GTA East Local Needs and Next Steps** <u>*Presentation Summary – Bulk System:*</u> *Joe Toneguzzo and Jiya Shoaib presented information on the bulk electricity system in the area, the regional electricity planning process and the needs that have been identified specifically in the Pickering-Ajax-Whitby sub-region. To set the context for the discussion, an overview was provided of the bulk electricity system focusing on how the Pickering Nuclear Generating Station (NGS) and the Cherrywood Transformer Station (TS) in Pickering serve the 900 MW demand in south Durham Region. Once Pickering NGS is closed, Clarington TS (currently under construction) will help transform electricity from the 500KV system supplied by the Darlington NGS to the 230KV lines currently supplied by the Pickering NGS.* Questions and feedback from the LAC members: • Ontario Power Generation (OPG) is currently collecting information on uses for the Pickering NGS following its closure. ○ OPG is undertaking a Re-purposing Pickering Study and they are working with the city and community to determine the future of the site. The site will continue to house spent fuel until a long-term solution is developed. • What is the capacity at Pickering NGS? ○ The facility produces 3,000 MW from six units each producing 500MW. This provides baseload electricity generation which means it runs 24 hours/day, 7 days/week, and 365 days/year. • What is the date for the Clarington TS to be in-service? ○ Hydro One is building this TS and it is scheduled to be in-service in 2018. • Without the closure of Pickering NGS, there is 3,000MW less being supplied in to the electricity grid – where is this generation coming from? Is the Durham Energy from Waste (EFW) facility part of this solution? ○ The IESO has known about the upcoming closure of Pickering NGS and has been planning for this. Over the last few years, there have been a number of gas plants built to assist with the shift off coal generation and these will run more when Pickering is out of service. There is also an opportunity to investigate Combined Heat and Power (CHP) projects once Pickering is out of service. The Durham EFW facility is also part of the solution. ○ It was also noted that the Seaton TS will be able to serve approximately 150 MW of demand and this already takes in to consideration a considerable amount of conservation. The TS will be 170MVA which is a standard station size and is the optimum size for this station given the pace of growth in the area. The facility will have a lifespan of 40-50 years.	

	<u>Presentation Summary – Near – Term Regional Needs and Plan:</u> From a regional planning perspective, two sub-regions were identified based on the type of needs within the larger GTA East region: Pickering-Ajax-Whitby and Oshawa-Clarington. *One near-term need for transformation capacity was identified for the Oshawa-Clarington area. This need was further assessed by a Hydro One led Local Planning Working Group in 2015. This Working Group recommended a new step-down transformer station (currently called Enfield TS) for providing the required transformation capacity to Local Distribution Companies serving the Oshawa-Clarington area.* *Two near-term needs were identified in the Pickering-Ajax-Whitby area - the need for additional transformation <u>capacity</u> to be in-service by 2018 to support urban and greenfield growth in Pickering; and a need to investigate the value of addressing <u>restoration</u> criteria for rare failure event. Three options were explored to address the transformation capacity need, an economic analysis was conducted and based on the results, a new transformer station near the community of Seaton was recommended to meet the near-term transformation capacity need. In order to connect this new station, a small length of an existing transmission line would also have to be rebuilt from single to double circuit. Veridian has begun the Environmental Assessment (EA) process for the new station and Hydro One will begin the EA for the transmission line portion of the project. For the restoration needs, the Working Group is exploring the rationale for meeting the restoration criteria for these rare failure events and will report back at the next LAC meeting.* Questions and feedback from the LAC members: • What growth assumptions are being used in the study – housing stats etc.? ○ The Local Distribution Companies (LDCs) closely monitor growth and development activity and discuss this growth with the municipal planners. Once each LDC has developed a growth forecast, this is provided to the IESO and the forecasts are then combined into one regional planning forecast. The timing of developments is monitored. ○ A LAC member noted that at the provincial level, a growth plan is developed with a forecast. This plan is sent to the region, where it is distributed to the local municipalities and subsequently divided into neighbourhoods. This information is shared with the LDCs every year. • Who sets the standards for energy consumption for the average house? ○ The LDCs develop the growth forecasts and incorporate changes such as the addition of household renewable projects (microFIT) and increased energy efficiency. The forecasts are also discussed with the municipalities. An important consideration is that population growth does not match energy growth – energy efficiency is better today, so energy growth is less than population growth. • There is a large potential for changes in the study horizon with regards to electricity usage from homes. A net zero home is opening in Ajax. Energy storage is increasing. ○ These trends have been accounted for in developing the forecast. Consumer behaviour plays an important part in electricity planning. • Has the Pickering airport been accounted for? ○ The airport has not been included in the load forecast.	☐ Restoration cost-benefit analysis to be presented at next LAC meeting

	• What assumptions are being made with regards to the changes in industry and jobs? Is there a factor that is being used? ○ Municipal population and employment forecasts drive the forecast. Since there is a degree of uncertainly, there could be low, medium and high growth scenarios for some regions. • Where is the electricity capacity coming from to replace Pickering NGS? We can't expect expensive gas to fill this void. ○ On the provincial system level, there is generation capacity to supply the system from a combination of combined cycle gas generation and other renewable generation sources. There is also a need to transform electricity locally. Until 2024, there is lots of supply provincially. Beyond this, we will need to look at other solutions and the provincial government is about to start the next Long-term Energy Plan to look at this. • Is there an advantage for Site #3 in Seaton to be closer or further away from growth? ○ Site 3 is the least advantageous due to its distance from the geographic centre of the new electrical demand. Other factors also need to be considered such as the distance to a transmission line etc. If it is located further away, losses are factored in as well. • Does it make a difference that the province owns lands in Seaton? ○ All the new Seaton TS stations sites being considered are owned by Infrastructure Ontario; however the portion of the transmission line will be rebuilt within the existing Hydro One right-of-way • What is the cost difference between the options to address capacity needs (slide 26)? ○ The transformer station and line is about $60M and the distribution feeders are about $70-100M. A new station is the lowest cost alternative; it is more costly to use the existing transformer stations and build feeders through the Rouge Valley. • Need to have a level playing field across all of the municipalities (for anything that becomes mandatory for developers) <u>*Presentation Summary – Mid- and Long-Term Needs*</u> *A key focus of the GTA East LAC is to discuss the mid and long-term considerations for the area and the community's preferred options to supply the long-term electricity demand. This includes conservation and demand management, and community self-sufficiency options. The LAC will also be asked to provide feedback on how to engage the community on the development of a long-term electricity strategy for the region.* Questions and feedback from the LAC members: • What is the land needed for solar generation on a large scale? ○ A LAC member noted that for 1MW of solar, 5-6 acres of land is needed. • Behaviour modification is outside of our control. What is the biggest bang for the buck in regards to infrastructure? Renewables can't be prescribed through planning – where are the provincial partners? ○ Electricity planners are part of this discussion and we can influence this through policy such as the Long-term Energy Plan. • The provincial government doesn't have any regulations in place for a builder to add solar panels. If these regulations were in place, this would change things. • Need a level playing field – there can't be different regulations in different	☐ Community priorities and preferences for addressing long-term electricity needs to be discussed at next LAC meeting

	municipalities. • The cost of solar panels is going down and the quality is going up • A partnership between builders, municipalities and the province is needed • Solar energy also has a negative effect on the province through the Global Adjustment. It will drive out industry if the province keeps putting panels on the system at premium costs. ○ The subsidy is part of the global adjustment; however, we are looking at net metering. This would eliminate this subsidy. • Why are we looking at new transmission instead of distributed generation (DG) for a subdivision? ○ Solar panels alone will not eliminate the need for Seaton TS which serves new sub divisions. DG is a viable solution however experience shows that people want a wire connecting their home or business to the grid to provide supply security. Cost is a factor and it is uneconomical to have grid supply and DG.	
	LDC Presentations <u>Veridian Presentation - Questions/Feedback</u> • Can there be a micro-grid the size of Seaton? ○ Yes, however this was not factored in to the analysis because the need is immediate, given lead times. Other opportunities are being explored such as combined heat and power plants • What are the steps to looking in to a micro-grid? Suggest a sub-committee of LAC members be established to look in to micro-grids. ○ Micro-grids become more complicated due to the broader policy implications such as purchase agreements, having a steam host etc. • Has the opportunity to connect to Markham been explored? <u>Whitby Hydro Presentation - Questions/Feedback</u> • No questions <u>Oshawa PUC Presentation - Questions/Feedback</u> • To what extent have the LDCs collaborated with other countries that are experiencing the same issues (i.e. development of micro-grids) ○ Europe is further ahead on combined heat and power projects. Australia has strong policy, but in Ontario there may be pushback. Asia-Pacific is also very proactive. LDCs are aware of what other countries are doing but the business, policy and development context is not as advanced in Canada.. • The global spotlight isn't energy, its greenhouse gas emissions ○ The existing system is very green. The province is trying to do more in this area such as moving transportation to electricity. ○ The market has to drive some of this. For example, a combined heat and power project in Seaton would need a private developer, not the LDCs, along with a secure customer base. Also, distribution wires would still need to be built.	☐ Investigate establishing a dedicated micro-grid LAC group before next LAC meeting

	Public Questions • With the closure of Pickering NGS, does the Special Protection System (SPS) for Darlington NGS need to be upgraded given that it takes several years? ○ Local reliability is maintained by the development of Clarington TS after the closure of Pickering NGS. • Given that there is a 160 MW demand for the Pickering area, what is the total capacity in the area over the next 20 years? ○ The Seaton community is the main driver for the near-term capacity. • Will the next Long-term Energy Plan include off-shore wind; there is currently a 5km moratorium from the shoreline? ○ The IESO does not have a mandate for such policy; the next version of the LTEP will reveal the provincial renewable energy policy as mandated by the government.	
6	**Next Meeting & Adjournment** • Focus of the next meeting is identifying priorities for addressing the mid- and long-term needs so these ideas can be included in this IRRP. The LAC will also be asked about other local priorities and initiatives such as status of community energy plans. Together, these two topics will be used to guide a discussion on the next steps for the LAC. • Next meeting to be held at the beginning of May. • Fall meeting to include a presentation of the completed IRRP.	

Meeting Information	
Date:	May 4, 2016
Location:	Ajax, ON
Subject:	GTA East Local Advisory Committee Meeting #2
Attendees:	**Committee Members in Attendance** Brad Anderson Stev Andis Ed Belsey Jeff Brooks Grant McGregor Ralph Sutton René C. Viau **Hydro One Distribution** Dhaval Patel Charlie Lee **Hydro One Transmission** Ajay Garg Jehangir Qayyum **IESO** Joe Toneguzzo Wajiha Shoaib Luisa Da Rocha **Veridian Connections** Craig Smith Ed Johnston **Whitby Hydro** Kevin Whitehead Faisal Habibullah Evan Wade **Oshawa PUC** Jayesh Shah Eric Andres Rajendra Patel Janet Taylor
LAC Meeting Materials:	http://www.ieso.ca/Pages/Participate/Regional-Planning/GTA-East/GTA-East.aspx

Key Topics	Follow up Actions
Opening Remarks and Roundtable Introductions • Everyone was welcomed to the meeting • Roundtable introductions were made	
Review of Summary from Meeting #1 • LAC members were asked for their feedback on the summary from the inaugural meeting. Being none, the summary was deemed final and a copy will be posted to the GTA East Engagement page on the IESO website.	

Presentation and Discussion – Near-Term Needs and Next Steps *<u>Presentation Summary – Near-Term Needs:</u>* *Joe Toneguzzo and Jiya Shoaib reviewed and provided an update on the two near-term needs identified for the Pickering-Ajax-Whitby sub-region presented at the inaugural LAC meeting. With regards to the <u>capacity</u> needs, it was noted that an environmental assessment (EA) is ongoing for the new transformer station in north Pickering and related upgrade to transmission circuits. Veridian and Hydro One have submitted a joint application. These processes will determine the location of the new station and line. With regards to the <u>restoration</u> need, an update was provided indicating that four options have been identified to address this need since the last LAC meeting, It has been determined that a refinement of the restoration analysis and the related solution recommendations will be determined as part of a Regional Infrastructure Plan lead by Hydro One and expected to be completed by Q1 2017. It was noted that the Integrated Regional Resource Plan (IRRP) for the Pickering-Ajax-Whitby area is to be completed by June 2016.* Questions and feedback from the LAC members: • Will the new transformer station (TS) in Pickering alleviate the generation connection restraint at the Cherrywood TS? ○ No. The new station is to service increased demand in north Pickering, while the generation connection restraint at the Cherrywood TS is related to the ability to add generation. • Is the Pickering Airport in scope for the regional plan? ○ Yes. It is a consideration for the long-term. • Does the plan account for climate change? ○ Yes. This was included in the study and had a minimal effect on the results. • Is there full redundancy in the system if one line goes down? ○ In the event of a single circuit failure, no one loses power. If two circuits fail, the power will go out. To address this, if switches are installed on the line, the station can receive power from either direction. There are currently no switches on the circuits from Cherrywood TS, but the economic and reliability justification for their implementation are being investigated. • Is time a parameter in the restoration evaluation? ○ Yes. This has a large impact in terms of cost. • What is the life span of the towers? ○ Towers can last 50+ years. They are continuously monitored and regularly maintained.	
LDC Presentations on their Conservation and Demand Management Plans *Each of the Local Distribution Companies in the GTA East area presented an overview of their Conservation and Demand Management Plans, including their conservation targets and the programs and initiatives that will help to achieve the targets.*	☐ Determine if changes to the High Performance New Construction program will follow the 2017 changes to the Ontario Building Code

LAC Member Discussion – Mid- and Long-Term Growth and Priorities

Presentation Summary: The LAC members were asked for feedback on the three questions below to help shape the IRRP's mid- and long-term priorities. It was noted that the plan is a living document and any mid-and long-term changes identified after the plan is posted will still become part of the on-going planning work in this region.

- *Where are the future key growth areas in your communities, along with the scope of the growth and timing, both residential and non-residential?*
- *What are your energy goals and objectives and is there a plan to achieve them? For the communities, do you have a community energy plan to address greenhouse gas emissions, climate change and extreme weather events?*
- *Can you share information on your policies and initiatives that will impact energy use (i.e. electrification of transit etc.)?*

The following feedback was received from LAC members.

<u>City of Pickering</u>

- The review of the provincial land use plans, including the growth plan, is expected in May. The growth plan will consider scenarios up to 2041. The review and update of municipal official plans, including Pickering's, will follow the approval of the new provincial plans.
- The city has a current corporate energy management plan (2014-2019) that sets out a roadmap to managing energy usage in city facilities.

<u>Durham Region</u>

- The region is planning to launch a 1.5 year long community energy planning (CEP) process in June in collaboration with the local municipalities, natural gas companies and LDCs. The plan will look out to 2050 and will be broad in scope. The region will be setting up a stakeholder advisory group for the CEP process.
    - An offer was made by the IESO to sit as a member of this advisory group, if requested.
- The Pickering airport Independent Advisor Consultation Paper could be released by the fall of 2016.
- The "white belt" along Highway 407, east of the Pickering Airport Lands, was identified as an area for potential future development through Regional Official Plan Amendment 128. This land area is approximately 4,150 acres. Further details on these lands can be found in the Region's Official Plan, specifically policy 7.3.11 and Land Use Schedule A.
- The Region is developing a climate change adaptation plan that is expected in the first half of 2017. The regional municipalities will develop their own climate change adaptation plans once the plan is developed at the regional level.
- In the long-term, the region is exploring electrification of transit such as light rail along the Highway 2 corridor.

☐ LAC members to review discussion questions and provide any additional information to be considered in the mid- to long-term portion of the IRRP

Town of Ajax

- Ajax will exceed its population and residential unit forecast for the mid- and long-term time periods for the downtown area.
    - Downtown Official Plan projections by 2031 are: 1,850 residential units and 3,500 people
    - Current approved development to be built by 2018 includes: 1,000 residential units, 1,800 people, 4,200 sq.m. retail Gross Floor Area and 5,000 sq.m. office Gross Floor Area
    - Proposed additional development (pending development applications) by 2022: 1,182 residential units and 2,140 people
- The steam plant in downtown Ajax has been redeveloped to a nameplate capacity of 18 MW and burns biomass. It has approvals to increase capacity to 25 MW.

Town of Whitby

- The town's official plan will be updated in 2017.
- The town is investigating a district energy feasibility study within the community of Brooklin.
- A community sustainability plan is expected in 2017.

General LAC Discussion

- Short-term growth in the region will be seen in greenfield areas before intensification happens in established parts of the region. Some municipal representatives indicated that they are receiving many queries for building condominiums; however this is not resulting in a similar number of buildings being built. However other municipalities in the area are seeing higher density facilities under development.
- Durham Region and the City of Pickering will be holding a builder education program on net zero homes in the coming weeks.

Energy Trends Discussion

- There is an increasing trend of using waste as clean energy, for example by using plasma torches. These technologies are not inexpensive but the technology exists. Photovoltaic film efficiency has increased and the costs have decreased from a decade ago. There is opportunity to take advantage of government programs aimed towards these clean energy technologies. An example is the energy from waste project in Durham Region.
- Electrification of personal vehicles will impact future electricity use. However, a number of factors affect the use and impact of these vehicles, such as climate, distances traveled, availability of charging stations, etc.
- A question was asked about the life extension and eventual retirement of the Pickering Nuclear and the impact to the local area in terms of electricity.
    - The IESO explained that the retirement has a major impact to the area; however a mitigating solution is already under development in the form of Clarington TS. This new TS will backstop the regional system once Pickering is retired.
- The group noted that distributed generation is prohibited from connecting at Cherrywood TS due to a short circuit constraint that impacts the older parts of the City of Pickering.
    - Hydro One is actively pursuing the removal of this constraint.

<u>Other Items</u> • The IESO informed LAC members that the provincial Long-Term Energy Plan is expected in 2017. Prior to its release, it is also expected that engagement will be undertaken, as was the case during the development of the 2013 Long-Term Energy Plan. • The province's climate action plan is expected to be released next month	
Public Questions • Will cap and trade increase electricity consumption? ○ Kilowatt savings won't be dampened by cap and trade.	
Next Steps & Adjournment • LAC members will be sent a copy of the mid- and long-term priorities identified in the meeting and asked for any additional material for consideration in the development of the IRRP. • Next LAC meeting to take place in the fall and will include a presentation of the completed IRRP and discussion of the next steps for the LAC.	

LAC Member Discussion – Mid- and Long-Term Growth and Priorities

The LAC members were asked for feedback on the three questions below to help shape the IRRP's mid- and long-term priorities. It was noted that the plan is a living document and any mid-and long-term changes identified after the plan is posted will still become part of the on-going planning work in this region.

- *Where are the future key growth areas in your communities, along with the scope of the growth and timing, both residential and non-residential?*
- *What are your energy goals and objectives and is there a plan to achieve them? For the communities, do you have a community energy plan to address greenhouse gas emissions, climate change and extreme weather events?*
- *Can you share information on your policies and initiatives that will impact energy use (i.e. electrification of transit etc.)?*

The following feedback was received from LAC members.

<u>City of Pickering</u>

- The review of the provincial land use plans, including the growth plan, is expected in May. The growth plan will consider scenarios up to 2041. The review and update of municipal official plans, including Pickering's, will follow the approval of the new provincial plans.
- The city has a current corporate energy management plan (2014-2019) that sets out a roadmap to managing energy usage in city facilities.

<u>Durham Region</u>

- The region is planning to launch a 1.5 year long community energy planning (CEP) process in June in collaboration with the local municipalities, natural gas companies and LDCs. The plan will look out to 2050 and will be broad in scope. The region will be setting up a stakeholder advisory group for the CEP process.
- The Pickering airport Independent Advisor Consultation Paper could be released by the fall of 2016.
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