THUNDER BAY SUB-REGION
INTEGRATED REGIONAL RESOURCE PLAN - APPENDICES

Part of the Northwest Ontario Planning Region | December 16, 2016

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Thunder Bay Sub-region IRRP

Appendix A: Demand Forecast – Methodology and Assumptions

A.1 Gross Demand Forecast

Figures A-1 and A-2 show the gross demand forecast scenarios developed for the Thunder Bay Sub-region and the gross LDC Transformer Station Peak Forecasts. The gross demand forecast reflects the regional peak demand and was developed based on customer connection requests, projections for new and existing industrial customers and the growth projections developed by the Local Distribution Companies. Appendices A.1.1 and A.1.2 describe the LDCs' gross demand forecasting methodologies and assumptions. The gross demand also includes expected peak demand consumption from various existing and potential transmission connected customers in the Thunder Bay Sub-region. Appendix A.1.3 describes how these assumptions were developed.

The forecasts for the Thunder Bay IRRP were created prior to the release of the provincial government's Climate Change Action Plan. The plan could have implications for the long-term load growth in the region. The magnitude of the region's long-term energy and capacity needs could also vary depending on electric vehicle penetration and operation (i.e., on-peak versus off-peak charging). Potential impacts are not yet well understood at a regional level. As such, future planning cycles will attempt to capture these impacts.

Table A-1: Gross Demand Forecast Scenarios 2016-2035 – Thunder Bay Sub-region

Gross Demand Forecast Scenarios (MW)																				
Subsystems	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Reference Scenario	340	349	351	352	372	373	375	377	378	380	383	387	390	393	396	400	403	407	411	414
High Scenario	340	349	352	356	377	381	385	388	392	396	401	405	409	414	417	420	424	428	431	435
Low Scenario	335	333	330	319	317	315	313	311	309	308	308	308	308	308	309	310	310	311	312	314

Table A-2: LDC Gross Station Peak Forecasts

LDC Gross Station Peak Demand Forecasts (MW)																				
Station	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Red Rock DS	4.0	4.0	4.0	4.0	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.2
Nipigon DS	2.2	2.2	2.3	2.3	2.3	2.4	2.4	2.4	2.5	2.5	2.5	2.6	2.6	2.6	2.7	2.7	2.8	2.8	2.8	2.9
Murillo DS	19	20	20	20	20	21	21	21	21	21	22	22	22	22	23	23	23	23	24	24
Port Arthur TS	43	43	44	44	45	46	46	47	48	48	50	51	53	54	56	58	60	62	63	65
Birch TS	78	79	80	82	83	84	84	85	86	88	89	90	92	94	95	97	98	100	102	103
Fort William TS	85	85	85	86	86	87	87	87	88	88	89	90	91	92	93	94	95	96	97	98

A.1.1 Hydro One Distribution Inc.: Gross Forecast Methodology and Assumptions

Hydro One Distribution provides service to the rural areas surrounding the service area of Thunder Bay Hydro Electricity Distribution Inc. ("Thunder Bay Hydro"). Power is supplied to the area by Murillo Distribution Station ("DS"), Port Arthur TS M6, Nipigon DS and Red Rock DS.

Hydro One Distribution distributes electricity to approximately 12,000 customers in the Thunder Bay area, of which 89% are residential customer and 11% is commercial/industrial. The primary supply voltages in the area are 25 kV and 12.5 kV.

Factors that Affect Electricity Demand

In the Hydro One Distribution service area in the Thunder Bay area, the electricity demand is winter peaking and is greatly affected by weather. Electricity demand is expected to grow at a slow steady rate.

Forecast Methodology and Assumptions

Forecast was completed based on historical load growth in the area with a provision for CDM.

A.1.2 Thunder Bay Hydro Electric Corporation: Gross Forecast Methodology and Assumptions

The history of Thunder Bay Hydro dates back to the 1890's when at the time customers were served from two separate utilities; Port Arthur Public Utilities Commission and Fort William Hydro. In 1970 the two utilities were amalgamated (along with the cities of the same names) to form Thunder Bay Hydro. Thunder Bay Hydro serves 50,482 customers as of December 31, 2015 within a service territory spanning 387 square kilometers bounded by the limits of the City of Thunder Bay and Fort William First Nation. Thunder Bay Hydro's service territory is neighbored on all sides by Hydro One Networks Inc.

Bulk power is supplied to Thunder Bay Hydro from three Hydro One owned transformer stations at 25 kV. Thunder Bay Hydro owns, operates and maintains approximately 923 km of overhead primary distribution circuits, 258 km of underground primary distribution circuits, four (4) 12 kV distribution stations and ten (10) 4 kV distribution stations. This includes; 23, 25 kV feeders; 6, 12 kV feeders; and 38, 4 kV feeders.

As of 2015, residential customers comprise approximately 90% of customer accounts while only constituting 35% of total electricity consumption. Thunder Bay Hydro's customer base and electricity consumption have remained relatively unchanged. The state of the local economy has likely contributed to this lack of growth in customer base. It can be noted that Large Industrial users account for a small portion of Thunder Bay Hydro's customer base, approximately 1%, conversely, they account for a large portion of Thunder Bay Hydro's consumption, approximately 50%.

Factors that Affect Electricity Demand

Thunder Bay's economy is driven by the Forestry Sector, Seas Freight (Grain), and Mining industry. For that reason, commodity prices and forecasts of Timber, Grain and Base Metals have been applied in the forecast. A decline in the size of the forestry industry throughout Northwestern Ontario has greatly impacted the local workforce, suppliers and service providers alike. As a result, the City of Thunder Bay has embarked on a strategic plan to provide diverse opportunities to promote local economic growth. Future government spending on infrastructure to support mining has the potential to impact growth and in turn electricity demands in the region.

There is not an updated local Gross Domestic Product (GDP) forecast that has been considered for the forecast electricity demand. Instead, forecast values of national unemployment, commodity prices, and inflation from third party sources were used for the forecast.

The City of Thunder Bay is a winter peaking region, where peak (180 MW in 2015) typically occurs in December or January, mid-week, in the evening; driven by a combination of industrial, commercial and residential loads, with peaks trending heating requirements. The 2015 winter baseload approaches 140 MW during the week, and summer baseloads of around 70 MW, with peaks as high as 160 MW driven by air-conditioning load. Extreme cold weather increases peak demand for Thunder Bay Hydro, but is forecast as nominal for the purposes of the demand forecast.

A fire that destroyed the Great West Timber mill in Thunder Bay has removed the possibility of that load (7 MW) returning to the Port Arthur TS in the near and mid-term.

Forecast Methodology and Assumptions

Thunder Bay Hydro’s forecast was developed by examining the last 10 years of gross load on a monthly basis from each of the three Hydro One fed transformer stations as well as the aggregated system load. In addition to load, historical and forecast values of the following factors were analyzed for their effect on load in the area; local and national unemployment rates, commodity prices for timber, grain and metal, cold weather peak and average temperature, consumer price index (CPI) and inflation.

For the factors that have been determined to affect demand, the last 10 years of data was used to create a model using multiple linear regression methods. Independent forecasts for the factors were then assembled, and used as a basis for predicting future demand. An annual growth rate of 1.5% was applied to account for factors which would not reasonably be picked up in the model, such as potential additional load due to mining development in the area.

A.1.6 Industrial Customer Gross Forecast Methodology and Assumptions

The IESO regularly communicates with existing and potential transmission-connected industrial customers to ensure there is an understanding of their future electricity demand. In the Thundery Bay Sub-region, potential, new industrial customers account for a significant amount of the forecast demand growth. However, the magnitude and timing of the electrical demand growth associated with large industrial customers, especially those in the natural resource sector (e.g., mining, oil, forestry) depend on a number of external factors such as the commodity price of the resource, the economic viability of the industrial project, and the ability to secure capital. In order to account for uncertainty of natural resource-based customers, the IESO developed multiple demand scenarios for potential and existing transmission-connected industrial customers by considering a number of factors, including:

- Customer plans
- Stage of development (e.g., under construction, undergoing an Environmental Assessment, still in exploration, etc.)
- Financial feasibility (e.g., results of publically available economic assessments)
- Potential environmental impacts
- Existing infrastructure and accessibility
- Global markets (e.g., commodity prices, customers and demand)

A.2 Estimated Peak Demand Savings from Provincial Energy Conservation Targets

Table A-7 shows the estimated peak demand savings from provincial conservation energy targets in the Thunder Bay Sub-region, by LDC Transformer Station (TS). These estimates were developed using the methodology described in Appendix A.2.1 below, and were considered in the development of planning forecasts.

A-3: Estimated Peak Demand Savings from Provincial Energy Targets in the Thunder Bay Sub-region, by LDC TS - 2016-2035

Estimated Peak Demand Savings from Provincial Energy Conservation Target (MW)																				
Station	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Red Rock DS	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Nipigon DS	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Murillo DS	0.1	0.2	0.4	0.5	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.5	1.6	1.8	1.9	2.1	2.1	2.1	2.1	2.2
Port Arthur TS	0.3	0.5	0.8	1.2	1.5	1.7	2.0	2.2	2.4	2.7	3.1	3.5	3.8	4.4	4.8	5.2	5.4	5.6	5.7	5.9
Birch TS	0.5	0.9	1.5	2.2	2.7	3.2	3.7	4.1	4.4	5.0	5.6	6.2	6.7	7.5	8.2	8.7	8.9	9.0	9.2	9.4
Fort William TS	0.6	0.9	1.6	2.3	2.8	3.3	3.8	4.2	4.5	5.0	5.5	6.1	6.6	7.4	8.0	8.5	8.6	8.7	8.7	8.8

A.2.1 Methodology to Estimate Peak Demand Savings from Provincial Energy Targets

The estimated peak demand savings assumptions considered in the planning forecast 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. It is important to note that the Time-of-Use ("TOU") rates and demand response ("DR") resources focus on peak demand reduction rather than energy savings and, as such, are not reflected in the 30 TWh energy target. The savings from potential DR resources are not included in the forecast and are instead considered possible solutions to identified needs.

To assess the peak demand savings from the provincial conservation targets, two provincial 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 are 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 from three categories: (1) TOU rates, (2) C&S and (3) EE programs. 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 shown in Table A-4, using 2013 as a base year.

Table A-4: Estimated Peak Demand Savings from Provincial Energy Conservation Targets (percent of gross load)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
C&S	0.0%	0.3%	0.4%	1.0%	1.4%	1.7%	2.1%	2.3%	2.4%	2.5%	2.7%	2.9%	3.3%	3.6%	3.9%	4.1%	4.4%	4.4%	4.4%	4.4%	4.4%
TOU	0.0%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
EE programs	0.0%	0.1%	0.7%	1.2%	1.8%	2.4%	2.5%	2.9%	3.2%	3.6%	3.9%	4.2%	4.4%	4.6%	4.9%	5.2%	5.5%	5.5%	5.5%	5.5%	5.5%
Total	**0.0%**	**1.1%**	**1.8%**	**2.9%**	**3.9%**	**4.7%**	**5.3%**	**5.9%**	**6.3%**	**6.8%**	**7.2%**	**7.7%**	**8.3%**	**8.9%**	**9.4%**	**10.0%**	**10.5%**	**10.5%**	**10.5%**	**10.5%**	**10.5%**

These percentages were applied to the gross demand forecasts at the TS 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 Thunder Bay IRRP to monitor actual demand savings, and to assess conservation potential in the sub-region, will assist in developing region-specific conservation assumptions going forward.

A.3 Expected Peak Demand Contribution of Contracted Distributed Generation

The installed capacity of contracted DG is adjusted to reflect the expected power output at the time of local area peak, based on resource-specific peak capacity contribution values. The expected peak demand contribution of contracted DG in the Thunder Bay Sub-region is show in Table A-5. The total installed capacity of contracted DG in the Thunder Bay Sub-region can be found in Section A.3.1.

Table A-5: Expected Peak Demand Contribution from Contracted Distributed Generation

Expected Peak Demand Contribution from Contracted Distributed Generation (MW)																			
2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01

A.3.1 Installed Capacity of Contracted Distributed Generation in the Thunder Bay Sub-region

Table A-6 shows the installed capacity of contracted DG in the West of Thundery Bay Sub-region, which was active as of March, 2016

Table A-6: Installed Capacity of Distributed Generation in the Thunder Bay Sub-region

Installed Capacity of Distributed Generation in the Thunder Bay Sub-region (MW)																										
Fuel	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Solar	0.4	8.4	19.5	20.6	21.4	22.5	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8
Bioenergy	3.2	3.2	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Waterpower	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total	**4.1**	**12.1**	**23.8**	**24.9**	**25.7**	**26.8**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**	**27.1**

A.4 Planning Forecast Scenarios

As described in the main report, three Planning forecasts were developed for the Thunder Bay IRRP driven by the uncertainties surrounding various, potential industrial developments. Table A-7 shows the Planning Demand Forecasts for the Reference, High and Low scenarios respectively and Table A-8 shows the Planning Station Peak Demand Forecasts for the LDC Transformer Stations.

Table A-7: Reference Scenario Planning Demand Forecast 2015-2035 – Thunder Bay Sub-region

Planning Demand Forecast Scenarios (MW)																					
Subsystems	**2015 Historical**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Reference Scenario	314	339	347	347	347	366	367	367	368	369	370	372	373	376	377	379	381	385	388	391	395
High Scenario	314	339	347	349	351	371	374	377	380	383	385	389	392	395	398	400	402	405	408	412	415
Low Scenario	314	334	331	327	314	311	308	305	303	300	298	296	295	294	293	292	291	292	293	293	294

Table A-8: LDC Planning Station Peak Forecasts

Planning Station Peak Demand Forecasts (MW)																					
Station	**2015 Historical**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Red Rock DS	4.0	4.0	4.0	4.0	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Nipigon DS	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.6	2.6
Murillo DS	19.2	19.2	19.4	19.5	19.4	19.6	19.8	19.9	20.0	20.1	20.2	20.3	20.4	20.5	20.6	20.7	20.8	21.0	21.3	21.5	21.7
Port Arthur TS	34.2	42.3	42.6	42.8	43.0	43.4	43.8	44.2	44.7	45.1	45.5	46.6	47.8	49.0	50.1	51.3	52.7	54.3	56.0	57.7	59.6
Birch TS	74.0	77.9	78.5	78.8	79.3	79.8	80.3	80.5	81.3	82.0	82.5	83.4	84.3	85.3	86.1	86.9	88.0	89.5	91.0	92.5	94.1
Fort William TS	79.2	84.0	84.2	83.8	83.5	83.4	83.2	83.1	83.1	83.1	83.0	83.4	83.7	84.2	84.4	84.8	85.3	86.2	87.1	88.0	88.9

Thunder Bay IRRP

Appendix B: Summary of Planning Criteria Applied to the Thunder Bay Area

B.1 Pre-contingency Outages and Hydroelectric Conditions

For local area supply studies different credible combinations of reasonable worst-case conditions for generation output and pre-contingency facility outages[1] are considered:

Table B-1: Hydroelectric Generation Output Assumptions (General)

Hydroelectric Output	Pre-contingency State
98th Percentile	Normal – no elements on outage
85th Percentile	Single element outage

The local hydroelectric generation output assumed for study purposes are summarized below and based on 20 years of historical hydroelectric data:

Table B-2: Hydroelectric Generation Output Assumptions by Station (Winter)

Station	98th Percentile [MW]	85th Percentile [MW]
Agusdsbon GS	17.6	20.8
Alexander GS	38.7	45.8
Cameron Falls GS	49.0	57.9
Kakabeka Falls GS	13.2	15.6
Pine Potage GS	53.0	62.7
Silver Falls GS	18.6	22.0
Total	190.1	224.8

B.2 Equipment Loading Criteria

Section 7.1 of ORTAC specifies the following criteria for load security related to equipment loading and level of load loss allowed under the applicable credible contingencies defined in ORTAC 2.7.1 and 2.7.2, and NERC TPL-001-4:

- **Criterion I**: With all the transmission facilities in service, equipment loading must be within continuous ratings.

[1] Pre-contingency facility outages: Refers to the outage of a power system facility in the initial condition. Additional contingencies are considered on top of the outage.

- **Criterion II**: With one element out of service, equipment loading must be within applicable long-term ratings and not more than 150 MW of load may be interrupted. Planned load curtailment or load rejection, excluding voluntary demand management, is permissible only to account for local generation outages.
- **Criterion III**: With two elements out of service, equipment loading must be within applicable short-term emergency ratings. The equipment loading must be reduced to the applicable long-term emergency ratings in the time afforded by the short-term ratings. Planned load curtailment or load rejection exceeding 150 MW is permissible only to account for local generation outages. Not more than 600 MW of load may be interrupted by configuration and by planned load curtailment.

B.3 Voltage Criteria

Voltage criteria applied can be sub-categorized as: voltage magnitude/change, and voltage stability.

B.3.1 Voltage Magnitude / Change Criteria

The voltage magnitude and change criteria indicate the allowable range of pre-contingency and post-contingency voltage magnitudes as well as the allowable post-contingency voltage change before and after under load tap changer ("ULTC") action.

Table B-3: Summary of ORTAC Voltage Magnitude/Change Criteria

Nominal Bus Voltage [kV]	Pre-contingency		Post-contingency			
	Maximum	Minimum	Maximum	Minimum	Pre-ULTC Voltage Change	Post-ULTC Voltage Change
500	550	490	550	470	10%	10%
230	250	220	250	207	10%	10%
115	127	113	127	108	10%	10%
Transformer Station Secondary (e.g., 44, 27.6, 13.8 kV)	106% of nominal	98% of nominal	112% of nominal	88% of nominal	10%	5%

After the system is re-dispatched and system adjustments are made following a contingency condition, the system must return back to within acceptable pre-contingency limits.

B.3.2 Voltage Stability Criteria

Voltage stability analysis is carried out by generating pre- and post-contingency P-V curves for the system. Power transfer is limited to the lesser of the following:

- A pre-contingency transfer that is 10% lower than the voltage instability point of the pre-contingency P-V curve, or
- A pre-contingency transfer that results in a post-contingency power flow that is 5% lower than the voltage instability point of the post-contingency curve

B.4 Load Security and Restoration

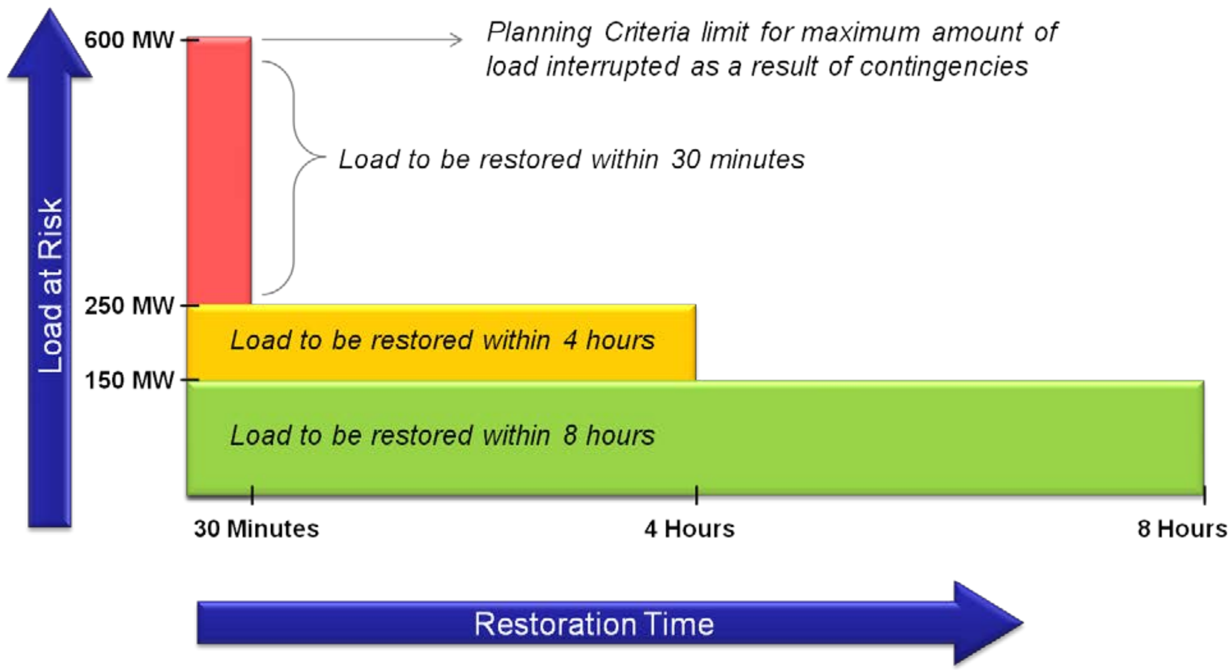
Table B-4: Summary of ORTAC Load Security Criteria

Condition	Load Curtailment Allowed [MW]	Total Load Loss Allowed (Load Curtailment + Lost by Configuration) [MW]
All transmission facilities in-service	N/A – All Load Must Be Continuously Supplied	
One element out-of-service	0*	150
Two elements out-of-service	150*	600

* Greater load curtailment is allowable to account for local generation outages, up to the magnitude of the respective generator(s). The total load loss does not change.

If the condition being studied results in an acceptable level of load loss, the load should be restored within the following timeframes.

Figure B-1: Summary of ORTAC Load Restoration Criteria



B.4 Transformer Station Capacity Needs in the Thunder Bay Sub-region

Table B-5 shows the peak demand forecasts for each transformer station in the Thunder Bay Sub-region, as well as the LMC of each station. Each of the station's peak electricity demand levels are forecast to remain within their respective LMCs, with the exception of Port Arthur TS, which is forecast to exceed its LMC by 2033.

Table B-5: Transformer Station Capacity Needs in the Thunder Bay Sub-region

Thunder Bay Sub-region Transformer Station Capacity Needs																					
	Station Capacity	*2015 Historic*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*	*2035*
TS	**Winter**	**Winter Peak**																				
Red Rock DS	9	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Nipigon DS	4	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3
Murillo DS	23	19	19	19	20	19	20	20	20	20	20	20	20	20	21	21	21	21	21	21	21	22
Birch TS	106	74	78	79	79	79	80	80	81	81	82	83	83	84	85	86	87	88	89	91	93	94
Fort Williams TS	104	79	84	84	84	83	83	83	83	83	83	83	83	84	84	84	85	85	86	87	88	89
Port Arthur TS	55	34	42	43	43	43	43	44	44	45	45	46	47	48	49	50	51	53	54	56	58	60

Thunder Bay IRRP

Appendix C: Power Quality

C.1 Short Circuit Study for the Thunder Bay 115 kV System

Hydro One conducted a short circuit study for four different operating scenarios on the Thunder Bay 115 kV system. The scenarios were chosen to capture the impact of different supply options on the fault levels at individual buses.

Scenario 1: Thunder Bay GS not running

Scenario 2: Thunder Bay GS running

Scenario 3: Thunder Bay GS not running, 3rd 230/115 kV autotransformer at Lakehead TS

Scenario 4: Thunder Bay GS not running, 30 km single circuit 230 kV line from Lakehead TS to Birch TS and a 230/115 kV autotransformer at Birch TS

Additionally, each scenario assumed all local generators were in-service, aside from Thunder Bay GS whose status is identified for each scenario. The results of the transmitter's analysis are shown in Table C-1.

The results show no significant benefit or impact to the fault level on the local 115 kV or 25 kV buses for the operation of Thunder Bay GS when compared to the two transmission alternatives.

Table C-1: Fault levels at buses supplied by the Thunder Bay 115 kV system for Scenarios 1-4

		Scenario 1				Scenario 2				Scenario 3				Scenario 4			
		Three phase fault		Line to ground fault		Three phase fault		Line to ground fault		Three phase fault		Line to ground fault		Three phase fault		Line to ground fault	
Station Name	Bus	Symm	Asym	Symm	Asym	Symm	Asym	Symm	Asym	Symm	Asym	Symm	Asym	Symm	Asym	Symm	Asym
	kV	kA	kA	kA	kA	kA	kA	kA	kA	kA	kA	kA	kA	kA	kA	kA	kA
Birch TS	115	13.294	14.809	12.080	12.841	15.396	17.754	14.653	15.873	13.569	15.079	12.404	13.153	14.378	16.222	15.707	18.206
	25	15.866	15.866	10.809	12.057	16.498	16.589	11.000	12.451	15.957	15.957	10.837	12.084	16.209	16.209	10.913	12.255
Port Arthur TS	115	11.722	12.507	11.354	12.304	12.674	13.484	12.234	13.190	11.996	12.778	11.700	12.640	11.832	12.615	11.919	12.851
	115	11.747	12.542	11.397	12.360	12.712	13.532	12.153	13.131	12.014	12.805	11.764	12.717	11.871	12.663	11.736	12.695
	25	10.421	10.698	8.109	8.972	10.555	10.851	8.163	9.041	10.460	10.737	8.125	8.988	10.439	10.715	8.116	8.979
Fort William TS	115	10.814	12.100	9.444	10.098	11.912	13.409	10.535	11.273	10.965	12.247	9.581	10.230	11.394	12.774	10.669	11.553
	115	10.199	11.240	8.449	8.790	11.321	12.588	9.705	10.119	10.352	11.389	8.585	8.921	10.790	11.929	9.797	10.427
	25	15.527	15.719	11.059	12.456	15.975	16.289	11.209	12.723	15.592	15.779	11.081	12.477	15.771	16.017	11.141	12.593
Customer Bus	115	10.169	12.488	10.245	13.065	10.918	13.347	11.021	13.956	10.275	12.593	10.343	13.168	10.570	12.941	10.882	13.784

C.2 Transient Voltage Study for the Thunder Bay 115 kV System

To further study the impact of Thunder Bay GS on the 115 kV system, the voltage response during a fault condition was monitored with and without the generator running. The fault condition tested was a three phase fault, administered on 115 kV circuit R2LB near Lakehead TS.

Figures C-1 and C-2 show the voltage response, both at the Birch 115 kV bus and the customer's 115 kV bus. While the voltage responses at both locations are very similar, the improvement in the post-contingency response that results from operating Thunder Bay GS in addition to any customer generation is small and unlikely to have any discernible benefit to equipment operation during three phase fault conditions.

Figure C-1: Transient voltage response at the Birch TS 115 kV bus to a fault administered on the 115 kV circuit R2LB near Lakehead TS

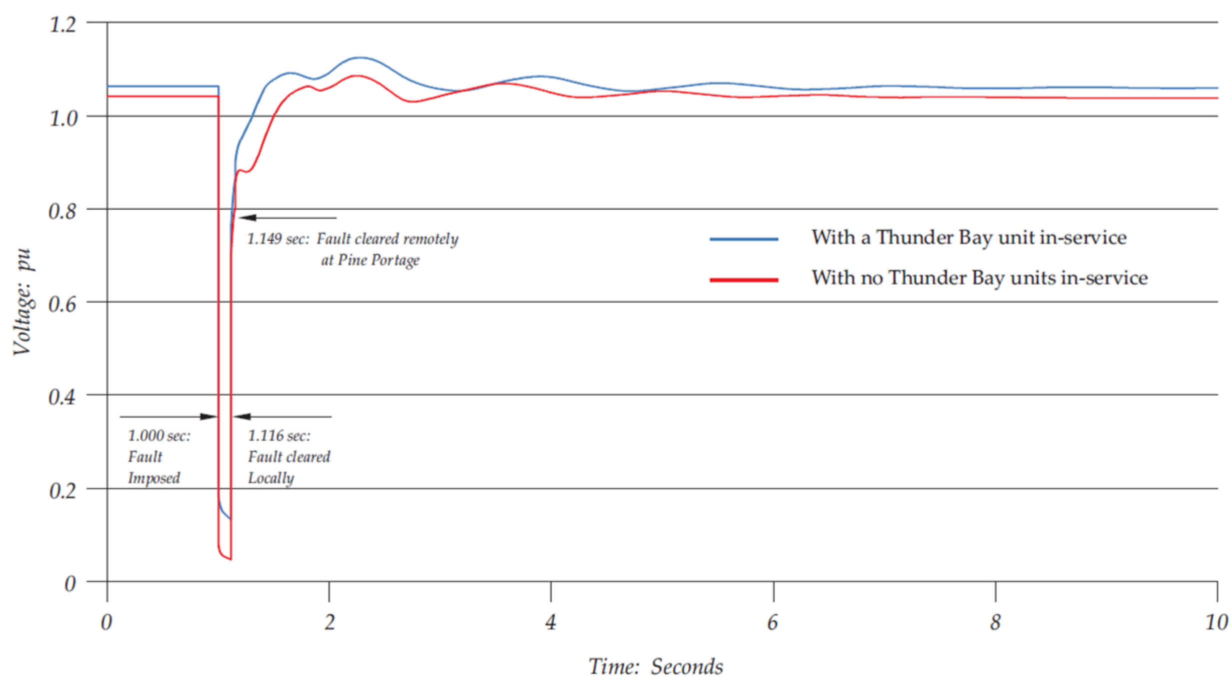
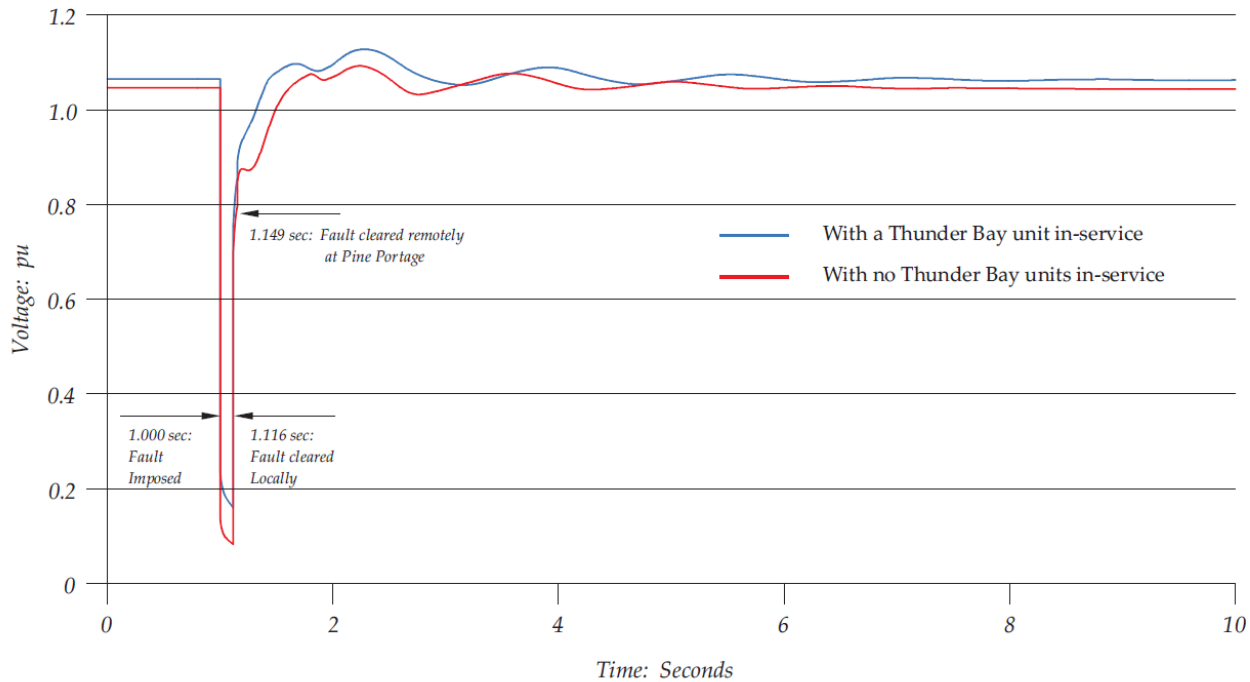


Figure C-2: Transient voltage response at the customer's 115 kV bus to a fault administered on the 115 kV circuit R2LB near Lakehead TS



Thunder Bay IRRP

Appendix D: Options to Increase Supply Capability on Thunder Bay 115 kV System

D.1 Transmission Reinforcement

Transmission reinforcement, or “wires” planning, reflects the traditional regional electricity planning approach associated with the development of centralized electric power systems. This approach involves using transmission and distribution infrastructure to supply a region’s electricity needs by taking power from the provincial electricity system. This model takes advantage of generation that is planned at the provincial level, along with generation sources typically located remotely from the region. Utilities, both transmitters and distributors, play a lead role in the development of this approach.

The Thunder Bay IRRP considered two transmission reinforcement alternatives – a third autotransformer at Lakehead TS and a third autotransformer at Birch TS and a 230 kV line from Lakehead TS to Birch TS.

These enhancements may be subject to regulatory approvals, such as a Class Environmental Assessment and utility rate filings. The costs of “wires” solutions would depend not only on the specific infrastructure involved, but also on the cost of providing energy at the provincial system level.

Appendix D.2 and D.3 provide more technical details relate to the options identified above.

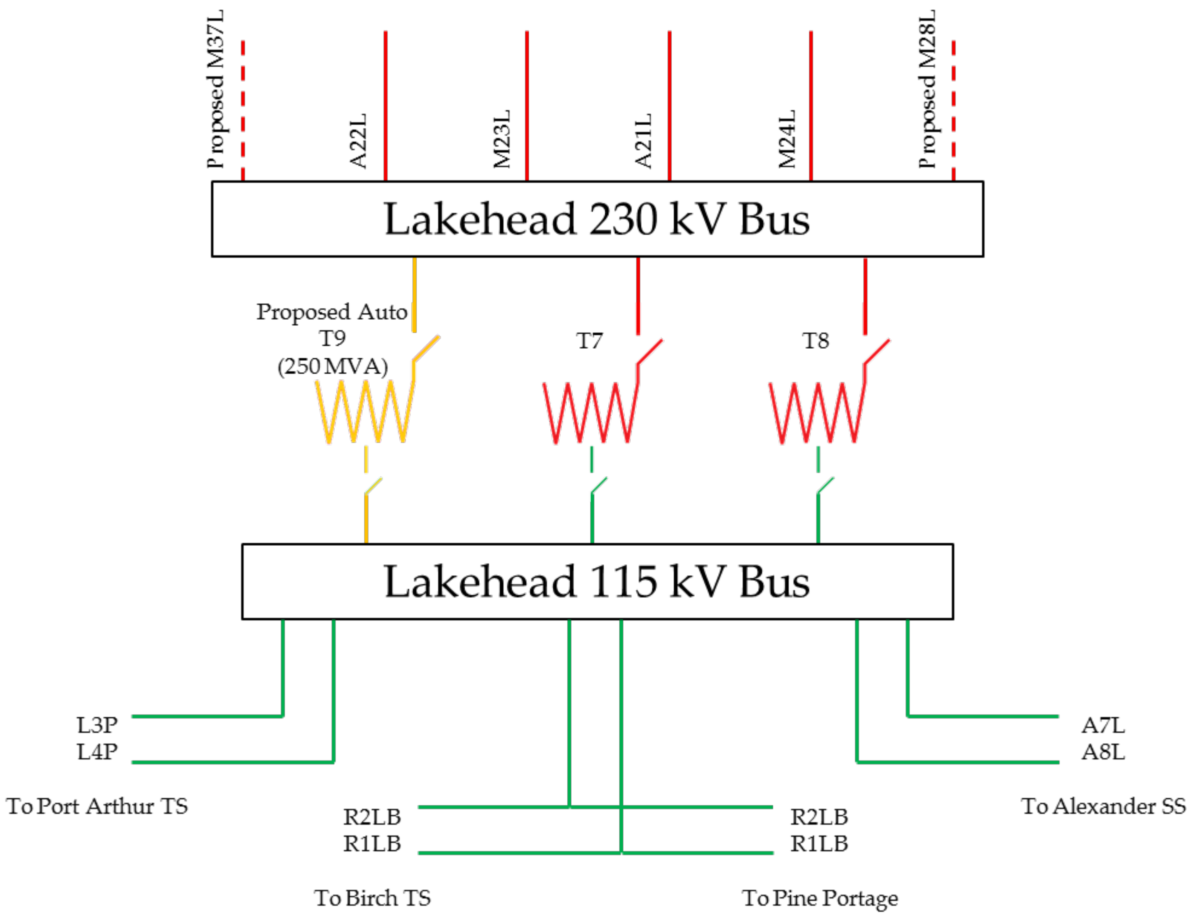
D.2 Third Autotransformer at Lakehead TS

Figure D-1 below shows a single line diagram ("SLD") depicting an additional, 230/115 kV autotransformer at Lakehead TS.

The new, 250 MVA autotransformer would increase the supply capacity of Lakehead TS by approximately 240 MW, allowing for all the growth forecast in the High scenario to be adequately supplied over the planning period.

Proposed circuits M37L and M28L below represent new circuits constructed as part of the new East-West Tie Line Project.[2]

Figure D-1: SLD – Third Autotransformer at Lakhead TS



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[2] http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/East-West%20Transmission%20Tie%20Line

D.3 New 230 kV line to Birch TS and 230/115 kV Autotransformer at Birch TS

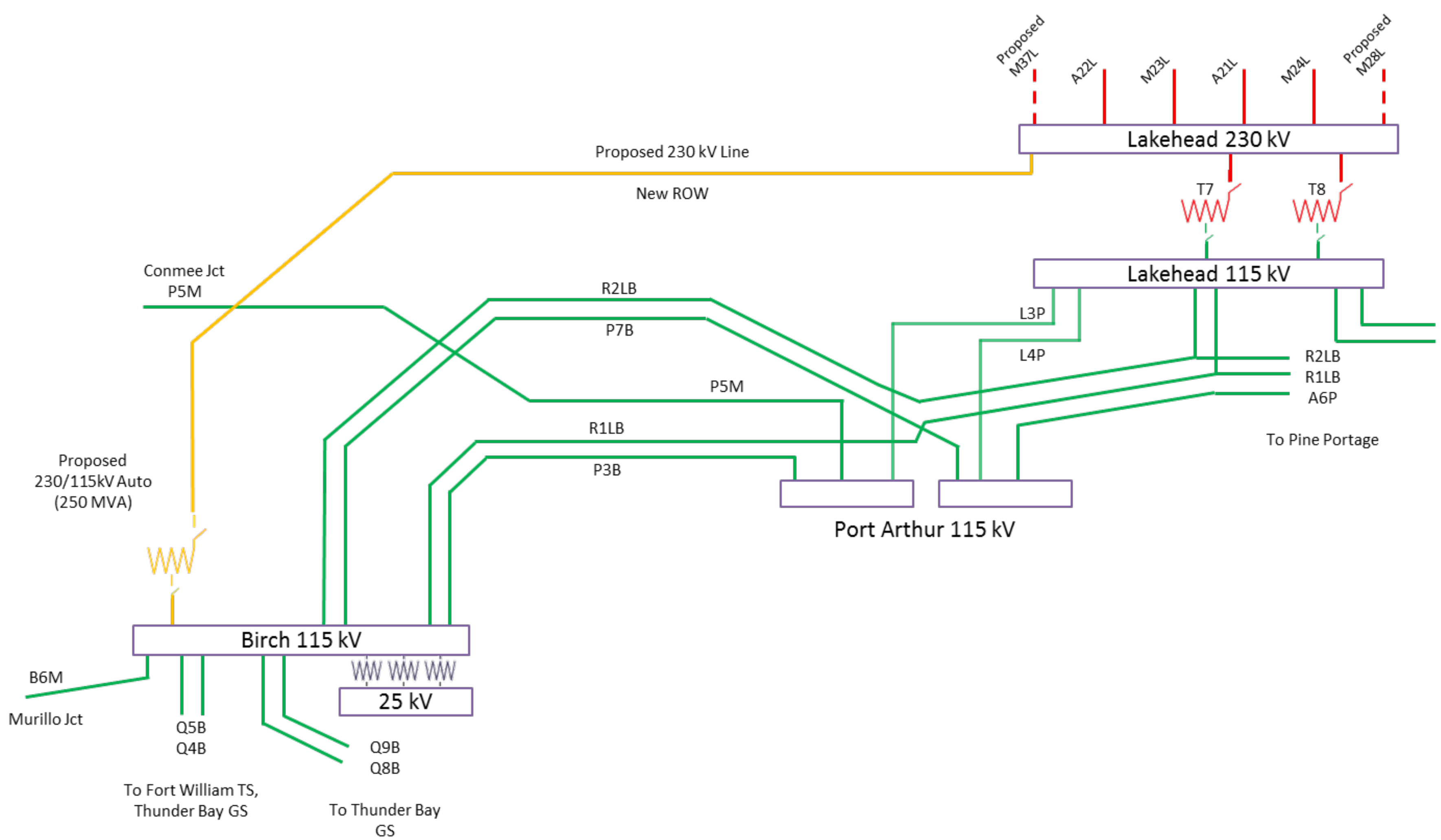
Figure D-2 below shows an SLD depicting a new, 230 kV line to Birch TS, and a 230/115 kV autotransformer at Birch TS.

The new, 250 MVA autotransformer at Birch TS would create a supply point for the southern part of Thunder Bay, with a supply capacity of approximately 240 MW, allowing for all the growth forecast in the High scenario to be adequately supplied over the planning period. It is assumed the new line would require a new Right of Way ("ROW").

Proposed circuits M37L and M28L below represent new circuits constructed as part of the new East-West Tie Line Project.[2]

The installation of a new line to Birch TS, along with a new autotransformer, provides supplementary benefits including providing extra supply capacity to the southern portion of Thunder Bay and additional system resiliency.

Figure D-2: SLD – New 230 kV line to Birch TS and 230/115 kV Autotransformer at Birch TS



D.4 Demand Response

Demand response ("DR")[3] enables consumers to reduce their electricity consumption in response to market prices and system needs. It allows the electricity system to utilize existing infrastructure, such as factories or hospitals, and is an efficient approach to meeting electrical demand needs.

DR was recently transitioned from a contract-based program to an auction-based mechanism held annually in December. The first DR auction was held in December, 2015 and secured over 400 MW of capacity for the winter commitment period and over 390 MW for the summer. Resolute FP Canada Inc. was a successful participant in the Thunder Bay Sub-region, offering 50 MW of capacity to participate in reducing provincial peak demand.[4]

The provincial DR program dispatches participants based on the Wholesale Market Clearing Price, which is driven by provincial peak demand. Typically the Thunder Bay Sub-region`s peak demand hours do not align with the Ontario peak. For this reason, the current, provincial DR program is not a reliable option to meet peak demand needs in the Thunder Bay area.

However, a pilot DR program was recommended by the IESO for the Brant IRRP[5] in order to identify costs and determine feasibility and potential for DR to meet regional supply capacity needs. If DR proves to be feasible and economic on a regional level, it could play an important role in other regional plans, including the Thunder Bay IRRP.

[3] More information on DR available at: http://www.ieso.ca/Pages/Ontario's-Power-System/Reliability-Through-Markets/Demand-Response.aspx

[4] DR Auction: Post-Auction Summary Report: http://reports.ieso.ca/public/DR-PostAuctionSummary/PUB_DR-PostAuctionSummary.xml

[5] Link Brant IRRP: http://www.ieso.ca/Documents/Regional-Planning/Burlington_to_Nanticoke/2015-Brant-IRRP-Report.pdf

D.5 Conservation

Conservation is important in managing demand in Ontario and plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. Conservation is achieved through a mix of program-related activities including behavioural changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results.

Within the Thunder Bay Sub-region, a significant portion of the forecast load growth is anticipated to be driven by new industrial development, which is assumed to include relatively efficient equipment given the inherent economic benefits and the latest codes and standards. Conservation expected to be achieved through provincial targets has already been included in the net demand forecast. Therefore, any potential for an additional amount of significant conservation that could address needs is limited.

Two of the available programs that transmission-connected industrial customers could be eligible for are the Industrial Conservation Initiative ("ICI") and the Industrial Accelerator program ("IAP"). The ICI encourages Class A customers to reduce their peak demand contributions, by providing a means to reduce their Global Adjustment charges.[6] IAP is geared to reducing electricity consumption on the provincial system, and to helping companies become more competitive by providing financial incentives that encourage investment in innovative process changes and equipment retrofits.[7] Opportunities for energy savings will continue to be explored for new and existing transmission-connected customers in the Thunder Bay Sub-region.

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[6] More information on how Global Adjustment is calculated for Class A customers is available at http://www.ieso.ca/Pages/Participate/Settlements/Global-Adjustment-for-Class-A.aspx

[7] More information on IAP is available at: http://www.ieso.ca/Pages/Participate/Industrial-Accelerator-Program/default.aspx

D.6 Distributed Energy Resources

Distributed Energy Resources such as DG and energy storage facilities have the potential to reduce the supply capacity requirements of the 230/115 kV autotransformers at Lakehead TS by supplying load on the 115 kV system during peak demand times.

As discussed in Section 5.3.3, 27 MW of DG is currently installed on the Thunder Bay 115 kV system with an effective capacity during peak demand times of approximately 5 MW. The low effective capacity is due to the majority of the DG installed on the system coming from solar facilities in which the generation output does not align with the Thunder Bay Sub-region’s electrical peak, which typically occurs overnight. Other DG technologies, such as bioenergy facilities, may be more effective at offsetting peak demand requirements and may be procured under existing programs such as the Feed-in Tariff (“FIT”) Program.[8]

The IESO is currently in the process of exploring how energy storage can be integrated into the day-to-day operation of Ontario's electricity system and market by procuring up to 50 MW of energy storage for Ontario in two phases.

In the first phase, the IESO selected storage technologies from five companies, for a total of 33.5 MW, to provide ancillary services to support increased reliability and efficiency of the grid. All projects are still under development, with the first expected to come into service before the end of 2016.

The second phase of the procurement was open to energy storage technologies with a range of performance characteristics. This phase was focused on two specific aspects of energy storage: its capacity value – the ability to be available to store energy and provide it back when called upon – and its arbitrage value – the ability to store energy during lower priced periods and inject it back into the electricity system when prices rise, and the value of energy increases.

As the technology matures within Ontario’s electricity system, future opportunities may exist to utilize energy storage to meet needs arising in regional planning activities. [9]

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[8] More information on the FIT Program - http://fit.powerauthority.on.ca/fit-program

[9] More information on Energy Storage initiatives in Ontario - http://www.ieso.ca/Pages/Ontario%27s-Power-System/Smart-Grid/Energy-Storage.aspx

Thunder Bay IRRP

Appendix E: Documentation of Local Advisory Committee Meetings

E.1 Meeting Summary for Thunder Bay Local Advisory Meeting #1

Meeting Summary	
Date:	Thursday, November 26, 2015
Location:	Thunder Bay, ON
Subject:	Thunder Bay Local Advisory Committee Meeting #1
Attendees:	**Committee Members** Hugh Briggs Ralph Bullough Harold Harkonen Larry Hebert Ellen Mortfield Ray Quinn Duff Stewart Jim Vezina Terry Wright **Hydro One Distribution** Cecilia Pang (via webinar) **Working Group - IESO** Nicole Hopper Alex Merrick Stephanie Aldersley Luisa Da Rocha **Thunder Bay Hydro** Rob Mace Don Zimak Tim Wilson Karla Bailey Joe McVety Andy Armitage
LAC Meeting Materials:	http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/Thunder-Bay.aspx

	Key Topics	Follow-up Actions
1	**Opening Remarks and Roundtable Introductions** • Mr. Mace, President, Thunder Bay Hydro welcomed everyone and discussed the committee and meeting focus • Roundtable introductions were made	
2	**Presentations by LDC Members of the Working Group** *Summary: Presentations were made by members of the Working Group to provide an introduction to the Local Distribution Companies (LDCs) in the Thunder Bay regional planning area. Copies of both presentations can be found on the LAC meeting link above.* • Presentation delivered by Mr. Mace, Thunder Bay Hydro • Presentation delivered by Ms. Pang, Hydro One Distribution	
3	**Role of Local Advisory Committee and Review of Manual**	

	• Ms. Da Rocha provided an overview of the role of the LAC: o Provide a local voice in electricity planning and advice and recommendations in the development of the plan o Identify additional stakeholders with regards to the development of the 20-year electricity plan for the Thunder Bay area • The LAC Member Manual was reviewed	☐ Collect remaining contact information from LAC members
4	**Presentation of Thunder Bay Electricity Planning Process** • Presentation delivered by Ms. Hopper, Senior Planner, IESO. A copy of the presentation is available on the LAC Meetings Materials link above. o Regional Electricity Planning Process o Electricity Planning in the Thunder Bay Area o Electricity Needs and Options **<u>Regional Electricity Planning Process</u>** *Presentation Summary: An overview was provided on Ontario's electricity sector and the regional planning process. The objective of regional planning is to identify and address local electricity needs ensuring that standards and criteria are met for a 20-year period. An integrated approach is used in regional planning that considers conservation, generation, transmission and innovative solutions. An overview was provided of regional and bulk planning in northwest Ontario. The work undertaken to date on the development of the regional plan were reviewed, including engagement with municipalities and First Nations, as well as the next steps.* • The map of the Thunder Bay regional planning area in the scoping report seems to include areas that should be part of other regional plans. For example, Oliver Paipoonge should be part of the Thunder Bay area. o IESO: The map in the scoping report has been revised since posting. • To which regional plan does the area north of Thunder Bay belong to? o IESO: The area directly to the north is part of the remote community connection plan, which is not a regional plan. Regional plans cover areas of the province that are grid connected and the remote community connections plan covers the part of the province that is not. There are two First Nations in the area north of Thunder Bay and they are part of the remote community plan, however they are two of the four communities that are not economic to connect to the grid at this time. The IESO is working with these communities to look at alternatives to diesel generation. • How are electrical needs identified? If a community identifies future needs, getting this information in to the plan will make a big difference. o IESO: There are a number of ways that needs are identified. Some needs are identified through technical planning such as looking at the reliability criteria that needs to be met, capability of the system as the demand grows and some needs may be raised for consideration by local	☐ Provide acronym list to the LAC members

communities. This is why we undertake engagement as one of the first steps in the planning process.

- How does a municipality know how much load is available?
  - IESO: The Local Distribution Company can supply this information.

Electricity Planning in the Thunder Bay Area

Presentation Summary – Existing System: An overview was provided of the Thunder Bay planning area and the electricity system. The regional study is looking at the 115kV system and the two autotransformers (steps power down from 230kV system to 115kV) at Lakehead Transformer Station as they are major supply points in to the area. The bulk system is being addressed through a separate planning process. Local generation is also accounted for in the study. Current supply and demand was discussed as well as local generation to meet this demand. The bulk of electricity comes in from the Lakehead autotransformers. Demand is currently 350MW and is served by local generation and supply from the Lakehead autotransformers.

- Hydro One also serves the United States Border Services Offices from infrastructure in the Thunder Bay area.
- Is Cameron Falls Generating Station included in the study?
  - IESO: Yes, it is connected to Alexander SS.
- Does local generation include wind farms?
  - IESO: There is one wind farm in the area and it is connected to the bulk system, not the regional system. It is considered as part of the supply to the area but it is not part of the study scope.
- Is generation measured as nameplate capacity?
  - IESO: No, it is measured as dependable capacity which is the amount of electricity available 98% of the time. This mostly affects the hydroelectric generation.
- Why is Thunder Bay Generating Station not in the dependable peak capacity chart?
  - IESO: It is included as part of the thermal generation (anything that is burned) along with Resolute and the Nipigon gas generator. Currently Thunder Bay GS has a limited fuel supply so its dependable capacity is very small. It is considered, but it is unable to provide capacity at this time based on its current contract.
- For hydro, how are drought years factored in to the 98% calculation?
  - 98%-of-time does include drought years

☐ Confirm if 98% factor includes drought years

Presentation Summary – Demand Drivers: Outreach has been undertaken to develop a picture for the entire northwest as well as work from the LDCs. Key drivers in this area include: growth in communities including spin-off economic activity from resource development across the northwest; potential local mining development; recovery of the forestry industry; and the gas-to-oil pipeline conversion project. There is uncertainty in the size and timing of development. Demand forecast includes a high and reference forecast which is net of conservation.

- Oil pumping stations are going to be off-grid
    - IESO: There is no final determination yet and we need to consider the possibility that they may connect to the grid
- What projects have not gone ahead and will not influence demand levels?
    - IESO: The IESO does not identify specific customer names

Electricity Needs and Options

Presentation Summary: Due to substantial uncertainties inherent in the demand forecast, the IESO is proposing a margin-based approach to planning in the Thunder Bay area. Many of the loads are very large and the plan needs to balance the need for reliability while ensuring that the economic risks are considered. Therefore, a margin-based approach is proposed that looks at potential drivers, the current capability of the system and what margin needs to be planned for. There is currently sufficient capacity - about 100MW of margin - to supply additional growth. Due to the way the system is configured, the Thunder Bay study also needs to look at growth in Greenstone. Needs arise in 2020 if all of the forecasted demand materializes and connects to the 115 kV system.. As a result, the Working Group is exploring options and solutions; there are currently no defined options. Evaluation of the options will consider cost, feasibility and reliability performance as well as other evaluation factors provided by the LAC.

- Is this planning process linked to emergency planning or climate adaptation planning in the city? Is there margin for disasters etc.?
    - Thunder Bay Hydro: Thunder Bay Hydro provides a forecast that includes predicted growth, conservation, and trends in economic development. At this point, the forecast doesn't include climate change, but it has been adjusted for conservation and combined heat and power projects. For emergency planning purposes, restoration of the system is part of the planning process that evaluates the current system and explores alternatives.
    - IESO: This is also included in the provincial reliability standards which not only looks at capacity, but how long it takes to restore loads in the event of an emergency.
- Margin could also be considered as MWs and extra fuel at the Thunder Bay GS could add 200MW of supply. The hindrance in the area isn't in physical assets, it's how it is being utilized for required demand.
    - IESO: The system in Thunder Bay is quite robust with double circuit supply. The largest possible contingency in the area would be losing one Lakehead autotransformer when the other is already down.
- Hopefully this doesn't bring the Thunder Bay GS conversion back to the table. It can't run very long on advanced biomass.
    - IESO: There are viable transmission solutions as well as local generation. Demand response is a possibility if it is only needed on a short-term basis.
- The Minister has said that when the power is required it will be there, but there are some examples where this is not the case. For example,

<table>
<tr>
<td></td>
<td>Greenstone Gold and Ear Falls.
o IESO: Neither of these are in the Thunder Bay area
• What is the lead time for a third autotransformer? How reactive can this be? If it is added, then more power is taken off the 230kV line, will this lessen power in other areas? Is this assuming the East-West Tie will be in place?
o IESO: This will be explored through the more detailed solutions. The new East West Tie is assumed to be in service in the Thunder Bay plan.
• The plan for this area needs to take into consideration other things going on in the province such as the closure of the Pickering Nuclear GS. Have calculations factored in any adverse effects from Pickering closing in 2020?
o IESO: Pickering GS is not part of the study. In regional planning, it is assumed that the provincial needs are being met. The needs for this study are not for provincial adequacy, but rather to supply the Thunder Bay area.
• Demand response (DR) has not been well used in this area and there are doubts that it can be well used.
o Thunder Bay Hydro: DR has been used in the region. Up until 1.5 – 2 years ago there was demand response until a policy decision closed the DR III program. There is an appetite for DR but we need to see if it becomes part of the IESO’s portfolio. When start looking at alternatives, this will help inform the IESO on program developments.
o IESO: Historically, the focus of the DR programs has been on system peak (provincial programs) and this hasn’t been a great match to the north because the north is winter peaking. If looking at a local program, it would need to be triggered on local needs instead of system needs.
• How is the quality of local supply evaluated for industrial customers? The loss of rotating generators and exposure to lightning is increasing to the point that some industrial customers can’t operate in the summer.
o IESO: This is not part of the reliability criteria. Local power quality concerns are typically addressed between the customer and the LDC or transmitter.</td>
<td>☐ Investigate opportunity for local DR program

☐ Consider quality of local supply as a criteria in the study</td>
</tr>
<tr>
<td>5</td>
<td>Discussion – Margin Based Approach
• This approach is like a crystal ball – any amount could be the right number depending on circumstances, even climate. Not sure there is a better system.
• Can there be a larger margin number with a special protection system (SPS)?
o IESO: SPS are an operating tool. In planning it is not assumed that an SPS will be used.
• Currently the 100MW margin represents a 25% surplus (on 450MW of demand). Is this standard? It is good to have a buffer because it is not known when things will happen.
o IESO: Regional planning typically doesn’t plan for a margin. This is a new approach with some risk that needs to be managed.
• What happens to the margin when a major catastrophe takes place?
o IESO: The study will look at the loss of power elements. Under current</td>
<td></td>
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</table>

load, this isn't a problem.

- Is the 100MW in one location or from around the region? Most of the lines are radial so a margin approach is needed.
    - IESO: The 100MW comes from different sources – transmission, generation and the Lakehead autotransformers. Solutions will be looked at in all locations.
- Will the margin include black start capability?
    - Thunder Bay Hydro: There is a different set of rules for planning and operating. For this study, 100MW of margin shouldn't be confused with needing this for operating purposes.
- The margin based approach is appropriate because we already have a margin.
    - Thunder Bay Hydro: Planning in other regions is based on organic growth, for example, 2% per year instead of a mining load coming on and needing 10MW. There is a lot more stability in organic based forecasting versus margin based forecasting.
- Agree with the margin based approach, but there is not enough information to say whether 100MW is enough.
- The margin shouldn't be funded by ratepayers, but rather the government in order to attract industry.
    - IESO: This is not typically included in the economic analysis. Currently, it is funded by ratepayers and we have to plan on that basis.
- Previously there were low, medium and high growth forecasts. Where does the margin fit in to this? Thunder Bay GS doesn't play a part in the 100MW but if there is growth, additional margin could be added by adding a fuel supply contract at Thunder Bay GS.
    - IESO: This depends on the costs and the characteristics of the need.
- The interconnection of the grid needs to be looked at. There may be a need to export which needs to the taken into consideration.
    - IESO: The plan could include a long-term permanent plan and a set of short-term options to deploy as needed. This will be looked at.

☐ Investigate including short-term options to deploy as needed in the plan

- With the degree of uncertainly, what is the trigger to adjusting the forecast?
    - IESO: Growth in the area will be monitored each year as part of updates to the IRRP.
- Do other regional planning areas in the Northwest use the margin based approach?
    - IESO: This will be confirmed.

☐ Determine whether the other NW plans use a margin based approach

- The 100 MW margin will be eliminated in 12-18 months with the new solar manufacturer. What happens if this company wipes out the margin?
    - IESO: A connection request hasn't been received yet from this company by the IESO, Hydro One or any LDC. It will likely need to be connected to the 230kV system in which case it would not affect the local margin. These needs should be discussed with the transmitter.

Discussion – Additional Local Priorities for Consideration

	• Are there any infrastructure issues that need to be addressed by Thunder Bay Hydro because of the regional plan? o Thunder Bay Hydro: The only overlap is at the TS capacity level, otherwise the local plans are not affected. • There is no more spinning reserve and this causes problems. For example, a company lost 10 motors with a lightning strike. • A missing factor is the resiliency of the system. • There is a drought in the area every four years and this could create a problem because there are no back-ups with Thunder Bay GS and Atikokan. **Discussion – Who Else Should We be Talking to?** • Educational sector to get information on trends, especially elementary schools as they have been good at getting this on board. • Generators. How does the regional plan know about changes the generators are making? o IESO: The IESO planning department is frequently in contact with generators about their facilities. As options are identified, the IESO will likely contact them to discuss feasibility and request cost estimates if appropriate. • Broader industrial community – for example the Ontario Mining Association (OMA) and other industry groups. Consider presenting to their committees. o IESO: The IESO periodically meets with the OMA and individual mines as well as those proposing mines. Common Voice Northwest is a good source of information on mines in the area. Presentations to group could cross all three plans underway in the northwest. • Local economic developers and the Chamber of Commerce. Not sure how much time we have to engage people.	☐ Review suggestions for additional outreach
	Other Priorities for Discussion • No additional items identified by the LAC members.	
6	**Next Steps & Closing Remarks** • Next meeting – Options for consideration to be brought back to the Committee in early March. Meeting time to remain the same.	☐ Next meeting to include options for consideration

E.2 Meeting Summary for Thunder Bay Local Advisory Meeting #2

<table>
<tr><th colspan="2">Meeting Summary</th></tr>
<tr><td>Date:</td><td>Wednesday, March 9, 2016</td></tr>
<tr><td>Location:</td><td>Thunder Bay, ON</td></tr>
<tr><td>Subject:</td><td>Thunder Bay Local Advisory Committee Meeting #2</td></tr>
<tr><td>Attendees:</td><td><u>Committee Members in Attendance</u>
Hugh Briggs
Ralph Bullough
Harold Harkonen
Larry Hebert
Ellen Mortfield
Ray Quinn
Erik Ross
Duff Stewart
Terry Wright

<u>Hydro One Transmission</u>
Bruce Parker
Hamid Hamadanizadeh (via webinar)

<u>Hydro One Distribution</u>
Cecilia Pang (via webinar)

<u>IESO</u>
Stephanie Aldersley
Bob Chow
Luisa Da Rocha
Nicole Hopper
Megan Lund

<u>Thunder Bay Hydro</u>
Rob Mace
Don Zimak
Tim Wilson
Karla Bailey
Joe McVety</td></tr>
<tr><td>LAC Meeting Materials:</td><td>http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/Thunder-Bay.aspx</td></tr>
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<tr><th>Key Topics</th><th>Follow-up Actions</th></tr>
<tr><td>Opening Remarks and Roundtable Introductions

• Ms. Da Rocha welcomed everyone and reviewed the meeting agenda
• Roundtable introductions were made</td><td></td></tr>
<tr><td>Review of Inaugural Meeting Summary and Follow-Up Actions

• Action items from the previous meeting were reviewed and the following updates were provided:
  o An acronym list was provided to the LAC members
  o It was confirmed that the 98% of time factor used for hydro generation includes drought years – this measures how much a hydro plant would output in 98% of hours over several decades</td><td>☐ Meeting summary to be posted on Thunder Bay LAC webpage</td></tr>
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- Power quality of local supply will be looked at as part of the study, however depending on the exact concern, it may be outside the study scope. In these cases, the concerns will be addressed to the most appropriate entity. - It was confirmed that the margin-based approach is generally not being used in other regional plans, except in the Brant area - Suggestions for additional outreach were considered and most have already been undertaken. Additional suggestions are welcome. - Follow-up items to be discussed later in the meeting – demand response and short-term options for the Thunder Bay plan - With no comments received on the inaugural meeting summary, it was deemed final and is to be posted on the Thunder Bay LAC webpage.	
Discussion of LAC Inquiries Received Since the Inaugural Meeting A new practice was introduced with a summary of all inquiries received from LAC members between meetings as well as the responses distributed to the LAC members. It is hoped that this will help with information sharing and communication among the LAC members.	
Recap of Electricity Needs in the Thunder Bay Planning Area *Presentation Summary: The study focuses on meeting load growth primarily in the Thunder Bay area, but also in the Greenstone area since supply to that area is linked to Thunder Bay. Electricity is currently supplied primarily by two autotransformers at the Lakehead Transformer Station (TS), as well as local hydro and thermal generation. The Load Meeting Capability (LMC) of the area is defined by the capability of these major supply sources. Today, there is sufficient supply to meet needs as well as accommodate 100MW of growth which could originate from community growth, mining growth in Thunder Bay and Greenstone, and the pipeline conversion. The current 100MW margin decreases by 50MW (* Correction from meeting: the capacity is 40MW) in 2022 with the expiry of a local generation contract. Overall, a plan is being prepared that takes into account the upcoming change in supply and the forecasted growth, acknowledging uncertainties, to ensure there is an adequate capability to supply new loads.* *Two additional needs to be addressed in the plan include ensuring there is adequate transformer station capacity in the City of Thunder Bay by the mid-2020s, and the need to address a circuit issue on the 115kV network in the City of Thunder Bay to ensure it meets reliability standards. Hydro One has begun to address the circuit issue based on a request by the Working Group.* Questions and feedback from LAC members: - What is accounting for the 50MW reduction in supply? - The contract is expiring for a generator and for planning purposes, when a contract expires, it is not assumed it will automatically renew. It is an option that it could renew. - Why is the Greenstone load considered in the Thunder Bay plan? - If new loads in Greenstone connect to the 115kV system, they will affect the Thunder Bay system because it is supplied by the Nipigon generator and the Lakehead autotransformers. If new loads connect to the 230kV	

system, it won't affect Thunder Bay. • Slide 6 - How much load growth is attributed to the pipeline conversion? o This portion of the chart includes the pipeline conversion, but also some mining growth in Greenstone. • Power quality is a problem across the area. Resolute is working closely with Hydro One with respect to lightning, asset reliability/maintenance. There were 14 instances one summer that shut the mill which is significant. In previous meetings, the installation of new lines such as the East-West Tie has been discussed and this is the time to discuss increasing reliability of all lines for industrial customers. Need to get power reliably to industrial customers. o IESO: This issue is separate from need #3 (slide 7). If there are additional customer issues, customers should raise these issues and they will be noted. The regional planning process is to plan to standards (capacity and security), but it cannot deal with this issue as many of the power quality issues do not always rest with the system. The transmitter and customer need to work towards a solution and IESO will help where possible on a system-wide basis. The short circuit level drives this issue; however there is no standard as to the appropriate level of short circuit. o Hydro One: It would be helpful to separate the issues of reliability from power quality. Reliability issues are about meeting customer demand under certain contingencies. Power quality doesn't affect the whole area, but individual customers. This will be addressed between the relevant customers and Hydro One. • Power quality doesn't affect just one customer - it is directly related to the decline in local generation. The future direction to more transmission connected supply will only accentuate the problem. The decision to forego local generation for transmission will not be successful. Performance criteria for the north are too broad; the voltage range is too broad for most large industrial customers. Having less local generation allows the system to operate more widely in the band and it will affect large industrial customers more. It is a planning decision of local generation versus transmission at early stages that sets the stage for future power quality. o IESO: Local generation does improve local conditions; however most of the generation in the area is for peaking purposes. Baseload electricity is still produced by hydro. Many of the generation facilities operate very few hours to meet peak conditions. Unless something is installed to address baseload needs, it won't change the situation. • Synchronous condensers could help if they are strategically located to maintain the strength of the system. • IESO: The issue of generation is complex and will be discussed as part of option development for the regional plan.	
Option Development to Address Needs in the Thunder Bay Planning Area *Presentation Summary: The planning approach to identifying and screening options is standard and applies to all parts of the province. The approach starts with identifying the needs and then identifying potential options. There are generally three ways to meet a capacity need: (1) reinforcing the system (wires approach) which includes bringing wires into the area and taking advantage of the supply available to the province as a whole, (2) developing local generation, and (3) reducing demand. Once the options are identified, they are assessed and compared by a set of criteria, including*	

cost, feasibility, reliability, environmental impacts, community acceptance and flexibility. *<u>Need #1 – Increasing the Thunder Bay Area LMC</u> – Options to increase the Thunder Bay LMC by 100 MW and ensure the area can be supplied following the loss of a Lakehead autotransformer when the other is out of service. Four potential options were presented to meet this need – a more detailed description of each of the options can be found in the meeting presentation.* Questions and Feedback on <u>Option #1 – reinforcing transmission supply</u>: • How long would it take to add a new auto transformer at Birch TS? Is it still 5-7 years despite the shorter length? o IESO: It would take 5-7 years to build both the autotransformer and transmission line as you still need to undertake the environmental assessment and leave to construct processes and work with community. • Are there any 230kV supplied customers in the Thunder Bay planning area, or Northwest Ontario as a whole? o IESO: There are none in the planning area. There may be a mine in the Fort Frances area. There may be some in the future. • Improvements in other methods of electricity generation will be introduced in the next 15-20 years for residential use at competitive rates, such as solar cells. In the Greenstone area, there are discussions about using gas as a favourable alternative due to the cost of lines and production. Has this been taken into consideration or is it being assuming that the mines will be using electricity? The study is adding a 25% increase in usage, however it may be less than that– are we preparing for the worst and accepting the second best? o IESO: There are no assumptions being made in this study. The load forecast includes potential loads and illustrates the worst case scenario for the Thunder Bay infrastructure system where these loads connect to the 115kV system. If new loads connect to 230kV system, they will not be part of the Thunder Bay system. No predictions are being made and the plan is not advocating what will happen. All of the developments are very uncertain which is one of the key difficulties in planning for this area – it cannot be predicted which load is more probable than another. Since it takes a long time to get infrastructure in place, development work may be started to reduce the total lead time. Development work takes 2-3 years, but no commitment has been made since this would require an advance on capital and for a load to be there. Questions and Feedback on <u>Option #2 – adding local generation</u>: • Is the study looking mainly at gas-fired generation? o IESO: The study is looking at gas and biomass. • The lead time for biomass is significantly less than the two years indicated in the presentation. o IESO: Correct, since there is a facility already generating from biomass. Questions and Feedback on <u>Option #3 – moving loads off the 115kV system</u>: • No questions or feedback Questions and Feedback on <u>Option #4 – reducing demand</u>: • No questions or feedback *<u>Need #2 – Ensuring Adequate Transformer Station Capacity in the City of Thunder Bay</u> –*	

Need for up to 15MW in the Port Arthur distribution service area starting around 2021 and up to 25MW in the Birch distribution service area starting around 2023. Four potential options were presented to meet this need – a more detailed description of each of the options can be found in the meeting presentation. Questions and Feedback on <u>all options</u>: • Is reducing demand practical for the area? There may be a little flexibility for efficiencies and conservation, but for the past ten years it has been taken care of for the area. o Thunder Bay Hydro: There are fairly significant conservation targets that need to be met as part of the Thunder Bay Hydro license. Another option is behind-the-meter generation that also reduces demand. There are existing combined heat and power plants and depending on where they are positioned, the demand can be reduced. However, generation can't be located in some areas because of short circuit issues and other work may be needed. Lots of scenarios need to be evaluated before making a decision. A further complication is the growth demand graph is fairly conservative – there is a need to plan now and evaluate yearly the status on the demand projection curve. • Is power generation on the island (biomass plant) being factored in to the plan? It is currently not operating close to its capacity? Can it be linked in to Thunder Bay Hydro or Hydro One? The station has huge options for getting electricity out – it has four lines that feed in to the northwest system. o IESO: It is one of the options being considered as a repurposed asset. • Is gas conversion being considered? The pipeline was built without sufficient capacity for the plant. o IESO: The working group is in discussion with the asset owners and have asked for information on continued biomass and gas conversion. It is realized that gas conversion would require a pipeline.	
Discussion of Potential Options and Priorities The following questions were posed to the LAC members for discussion: 1. Are the needs clearly laid out? 2. Today, we have identified several options that will be considered to meet the needs: • Are the options reasonable? • Are there additional options that we haven't thought of? 3. At our next LAC meeting, we will provide more information on the options to facilitate a more detailed discussion: • Is there any information in particular on these options that you think is required? 4. Is there anything else you would like to share with us at this time? General Discussion by the LAC members: • A great option is local generation, particularly behind-the-meter generation. Is this new and is there a big cost to the consumer and producer? o IESO: The current system in Ontario is green, relatively low cost and sufficient in terms of power and energy. In the last decade, there has been a change in that we now have the opportunity to generate locally. Wires	

are still considered the best option in many situations. Gas generation can be moved to where it is needed, and this was first tested in a number of locations in southern Ontario where it was successful in deferring transmission for as much as ten years. There are now more resources that are smaller in scale that can be located closer to the customer. The issue is that many are still very costly, and many don't provide capacity, just energy, such as wind and solar. In integrated planning, these different options will be considered, not just wires options that take power from the grid and bring it to a local area.

    - Thunder Bay Hydro: For behind-the-meter generation, not renewables, but combined heat and power, the challenge is a customer of a certain size is needed to make the project economic. The project is also needed in the right location – if the constraint is in the north end of the city and there is a project in the south, this doesn't help. There is also uncertainly around cap and trade because gas is being burned.
- Can more information be provided on cap and trade? Will this create a push to solar or geothermal energy that hasn't necessarily been economic yet?
    - Thunder Bay Hydro: This is not known yet in Ontario and the Ontario cap and trade is separate from federal initiatives. There is no indication of where the collected money will go. There is no market yet where green generation is subsidized by cap and trade. Distribution utilities are being told it won't be a big issue in selected supply, and there will only be an effect if there is a carbon cost on fuel. There is no other information to bring forward until the province puts out the cap and trade guidelines.
- What is the status of the East-West Tie?
    - IESO: The East-West Tie serves all of northwest Ontario. Regional need will be served by the East-West Tie or another source if it doesn't go ahead. The planning assumption is that the East-West Tie will be there. (*Note: since the Thunder Bay LAC meeting, the East-West Tie has been declared a priority project by the Minister of Energy*).
- There is a rumour that the East-West Tie won't have any power to send to the northwest because of the nuclear issues in southern Ontario. This is of concern to a number of groups in the area if East-West Tie doesn't go ahead.
- Is there an option to secure firm capacity from Manitoba if the East-West Tie doesn't go ahead?
    - IESO: At the moment, it is premature to speak with Manitoba.
    - Thunder Bay Hydro: The government is starting to develop the next Long-Term Energy Plan and this is where imports will be discussed.
- On the East-West Tie, is it mainly the east tie that is being upgraded? There are not new wires going to Manitoba so they will still have the same capacity.
    - IESO: Manitoba is the "back door". If power is lost on the East-West Tie, this is where the power comes from. It is good to have interconnections and there are now four in the northwest - Manitoba, Minnesota, and two at Wawa because the East-West Tie is doubled.
- Is IESO looking at new solutions such as geothermal, or is it just wires?
    - IESO: Planning is done at different levels. Many of the IESO programs are part of the long-term picture for the province. In regional planning, there are 21 regions and they need to be coordinated. Any regional resource is part of the provincial resources. It is a matter of looking for the optimal solution between the two.
- There will always be the need for wires, as they provide back-up - this is the challenge. Changes in technology can happen fast but we need to be ready.

- Thunder Bay Hydro: One of the challenges is bringing forward options that we don't necessarily know about. This will be looked at more moving forward. For example, there are no generators on the LAC. In the future, perhaps it should.

- Are there upgrades happening in the West of Thunder Bay?
  - IESO: There are potential bulk system needs in this area for mining and to meet the future needs for Atikokan. This upgrade would reinforce the system from Lakehead to Dryden. This study is behind the East-West Tie.
- How is it justified to Ear Falls and Greenstone that they can't get enough power, yet power is being supplied over the border to Pigeon River, Minnesota? This should be taken back to the political leaders.
  - IESO: Solutions have been identified - it is a matter of economics.
  - Hydro One: *(Post Meeting Update: Hydro One Distribution only supplies the area north of Pigeon River in Canada.)*
- There is a large 200MW manufacturing project in town that is being driven to a 230kV connection. While the preference is to connect to the 115kV, it can't handle it. Do they have any option, or is it 230kV or gas?
  - IESO: Depending on the project, it would be customer choice. There is also an assessment process to go through the IESO.

<u>Discussion of Option #1 – Reinforcing the Transmission Supply</u>

- Timelines are very general – add more specific timelines for each option.
- If East-West Tie is a requirement, an update on the project would be helpful
  - Thunder Bay Hydro: East-West Tie is not a prerequisite; a third autotransformer is required at Lakehead because of supply in Thunder Bay
  - IESO: If East-West Tie doesn't go ahead, other options would be looked at
- Why is there a desire to not put a third autotransformer at Lakehead. Would it make a difference to place it at Birch?
  - IESO: The third autotransformer at Lakehead is viable, but is still limited by the 115kV line. This is okay for the current need, but in longer-term it could end up trapping capacity at Lakehead. If the autotransformer is placed at Birch, it would need a 230kV connection.
- Should we look at a 3rd autotransformer at Port Arthur TS instead of Lakehead or Birch? Would the timeline be the same?
  - IESO: The timeline for a line and an autotransformer at Port Arthur TS is the same as a line and an autotransformer at Birch TS (5-7 years). We can consider an autotransformer at Port Arthur as an option.
- Is the mine at Port Arthur connected from Lakehead or Birch?
  - IESO: It is supplied by Lakehead.

<u>Discussion of Option #2 – Adding Local Generation</u>

- Has there been any consideration given to converting facilities to gas? Is the potential being looked at?
  - IESO: The need is relatively few hours per year; the expectation is it would run very few hours per year. There are a few facilities that could be re-purposed, or new facilities could be built. For generation, there is a need to look at where the fuel is coming from. If use the existing Thunder Bay GS, a gas line is needed. If it's a new plant, the location of new plant will determine if a new gas line is need. There are a few issues with regards to gas management, gas storage, pipeline location, peaking operation etc. For biomass, we are speaking with a proponent with biomass experience. We are learning that these facilities are all different – Resolute, Atikokan,

Thunder Bay. What is appropriate for the Thunder Bay station is to be determined, including who will source the biomass supply. For non-gas and non-thermal generation, there are renewables, but probably not enough. They could partially serve the need, but not all of the need. • Which is cheaper – East-West Tie or local gas generation? o IESO: In the IESO's December need report on the East-West Tie it was indicated that the economic option for the northwest is the East-West Tie because the system is adequate in terms of energy and capacity, therefore the rest of the grid could serve the northwest. • Has there been any consideration of a hybrid facility for gas and biomass that may respond quicker and if there is a lack of biomass it would run on gas? This could be cost-competitive to the East-West Tie if it runs more. o IESO: It is assumed in the study that Atikokan will continue as is until 2024 when its contract expires. It is not assumed that Thunder Bay GS biomass will continue once the contract expires. At the moment, the capacity factor is low, and it doesn't contribute very much for supply in northwest – it is mostly from hydro. • Does the regional load curve lend itself to energy storage technology, for example, compressed air storage? There are lots of abandoned mines in the area that can be used for this. o IESO: The issue with storage is that the planning requirement needs to look at dry years – 98% dependable. In these situations, pump storage will not help very much. • The Auditor's report said that the biomass facility is used nine days per year. If the East-West Tie is being built to increase availability of power, in Atikokan there is enough power to generate for the area. The costs to bring electricity to the point of sale should be added in. o IESO: Both plants are not running at a high capacity factor because of the fuel. If a more expensive fuel is used, such as biomass, then it is running against less expensive system resources. The system resources are adequate, economical and clean so anything that is running locally will need to offset this. Transmission is the adder to the system cost to deliver to local areas. In some areas, transmission costs are so high that it is more economical to generate locally. This is not the case for the northwest because of the East-West Tie. • Are line losses factored in to this approach? o IESO: Yes. As the second East-West Tie line is added, losses are lowered. <u>Discussion of Option #3 – Moving Loads off the 115kV</u> • No questions or feedback <u>Discussion of Option #43 – Reducing Demand</u> • Is behind-the-meter generation considered reducing demand? o IESO: Yes. • The new manufacturing facility will be 200MW (gas) so will this be considered as savings from a demand standpoint? o Thunder Bay Hydro: If it is behind-the-meter generation, it is not assumed to be part of the new load assuming it is connected. If it is self-generating it is not counted. <u>Any other options for the Working Group to consider?</u> • No feedback	☐ Send link to East-West Tie needs reports

Any additional information requested? • No feedback	
Public Questions • Has consideration been given to educating primary-level students about energy conservation and how they can make a difference? o IESO: This is out of scope for the plan development, but not out of scope for implementation of plan moving forward. This would be considered as part of the conservation programs. o Thunder Bay Hydro: In the past, there was a program for Grade 5 students and the schools still have a conservation and energy study at this level. Currently, there are no active programs for school aged children. There is small component on conservation as part of the spring education program on line safety. • In Slide 4, supply to Thunder Bay area, there is no generation. Does the committee have information about the operating characteristics for the hydro generating assets in the area? It was mentioned that the need in the area is associated with peak generation, and part of this discussion could be looking at the profiles for hydro assets and seeing if they can operate in this fashion to meet these needs. Some of these attributes were restricted previously, but could be brought back, and new hydro could also be looked in to. With regards to the information on slide 12, the life expectancy of a hydro facility is 80-100 years, not 20 compared to other options and the development lead time is different than 2-4 years. This information can be provided. Hydro assets can be managed differently to address needs. o IESO: In the first meeting there was a review of generation assets in the area – this information is posted online. More information would be welcomed. The presented asset information was geared towards thermal, not hydro. These options are being looked at because it is a peak need, but information would be welcomed on how hydro can address this. • There is a plan entitled, "Master Power Plan for the Northwest" to bring power to the northwest through a new 230kV line from Manitoba to Red Lake to the Ring of Fire. This removes the need for new transmission lines from southern Ontario, eliminates 1,200MW of generation, reduces emissions, saves $2 Billion and will reduce global adjustment costs. o IESO: The plan should be sent to the regional planning email address. Some of these issues are beyond the scope of regional planning and are more directly related to the Long-term Energy Plan which is currently being developed by the Ministry of Energy. They will be undertaking engagements as part of the development of the plan.	
Next Steps & Closing Remarks • Next meeting – A more detailed exploration of the options. • Subsequent meeting – Presentation of draft plan recommendations. • Request by a committee member for the LAC meeting to be closer to the city centre and on a transit route.	

E.3 Meeting Summary for Thunder Bay Local Advisory Meeting #3

Meeting Summary	
Date:	Monday, June 27, 2016
Location:	Thunder Bay, ON
Subject:	Thunder Bay Local Advisory Committee Meeting #3
Attendees:	**Committee Members in Attendance** Hugh Briggs Ralph Bullough Cameron Burgess Larry Hebert Ellen Mortfield Patricia Obie Ray Quinn Erik Ross Duff Stewart **Hydro One Transmission** Hamid Hamadanizadeh **Hydro One Distribution** Rich Baggerman (via webinar) **IESO** Stephanie Aldersley Bob Chow Luisa Da Rocha Megan Lund Salvatore Provvidenza Alex Merrick Terry Young **Thunder Bay Hydro** Rob Mace Tim Wilson Karla Bailey
LAC Meeting Materials:	http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/Thunder-Bay.aspx

Key Topics	Follow-up Actions
Opening Remarks and Roundtable Introductions • Ms. Da Rocha welcomed everyone and reviewed the meeting agenda • Roundtable introductions were made • Hugh Briggs from Lakehead University delivered opening remarks and noted that Lakehead University is celebrating their 51st anniversary this year as well as the 10th anniversary of the Orillia campus. Mr. Briggs highlighted several initiatives on campus including the $22 million retrofit of the power house and campus 10 years ago that reduced gas consumption by 45% and electricity by 18-22% and these savings have been maintained. The university is building on this by actively looking at a co-generation facility on campus and other energy initiatives. Lakehead University is also exploring next steps in the renovation of the science and research centre, and the development of a building for Indigenous programs.	

Review of LAC Meeting #2 Summary and Follow-Up Actions • The summary from LAC meeting #2 was reviewed with the committee and was deemed final with no changes to be made.	☐ Meeting summary to be posted on Thunder Bay LAC webpage
Discussion of LAC Inquiries Received Since the Last Meeting *Presentation Summary: In response to a LAC member inquiry regarding why renewable energy was not being considered for northern Ontario, a written answer was shared with the Committee. It was noted that the IESO announced 16 contracts in March for the first round of the Large Renewable Procurement. A key aspect of these proposals was connection availability and the northwest area of the province was identified as having no availability to connect projects of this size, although some availability exists for smaller renewable energy projects (up to 500 kilowatts). It was also noted that the regional planning process is designed to ensure the reliability and adequacy of a region's electricity system to supply demand while meeting accepted reliability criteria and planning standards. In the northwest, there are adequate resources to supply today's demand. The regional planning process is not intended to enable the connection of renewable generation where no new generation is required.* **Questions and feedback from LAC members:** • There is no mention of the East-West Tie? Are you looking at this? o This bulk transmission project's planned in service date is 2020. It is expected that there will be a significant amount of growth in the mining and pipeline sectors, and the East-West Tie will serve this growth in the northwest as a whole. • There was mention that there might not be enough nuclear power to send out to the northwest? o At the moment, there is sufficient capacity and very clean power will be available to supply the northwest; this is not an issue over the next while. Northern Ontario is winter peaking while the south is summer peaking, and this diversity helps with the availability of energy. o The provincial government is embarking on the development of their next Long-Term Energy Plan and they will be holding engagements across the province. The IESO will circulate information to the LAC once available.	
Recap of Electricity Needs in the Thunder Bay Planning Area *Presentation Summary: Since the last LAC meeting, a new demand forecast has been developed for the area that reflects a base year of 2015 (updated from 2013), incorporates new demand forecasts provided by Thunder Bay Hydro and Hydro One Distribution, and reflects updates to some of the industrial assumptions in the Greenstone - Marathon area which impact on the ability to meet demand in the Thunder Bay area. The updated demand forecast has resulted in an updated needs assessment. As part of the regional planning process, this needs assessment was developed based on the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC).* *Today, the Load Meeting Capability (LMC) in the area is adequate and there is 150MW of*	

margin which allows quite a bit of room for growth. Based on the updated forecasts, a need for additional capacity may arise in the late 2020's once the margin has been diminished. This would be a peaking need, it would occur during the winter months probably for a few hours a year when the hydro generators are dry and the load is high. Decisions do not have to be made today on new infrastructure as there is room for growth and the amount of margin will be monitored. If the margin diminishes in the future, there is time to evaluate the options and determine the best option. *Some minor needs were also identified in the area including the potential need for step down transformer capacity at Port Arthur Transformer Station (TS) which may occur around 2030. This is a good opportunity to look at a variety of options such as conservation or demand response to try and defer this need as far as possible. Another minor need is a line uprating needed on the R2LB line which Hydro One is addressing by increasing the clearance of a section of the line.* **Questions and feedback from LAC members:** • What is ORTAC? o The "Ontario Resource and Transmission Assessment Criteria" is the IESO's criteria used when developing regional plans. • Where do biomass generators fit into the bulk/regional system and how can long range planning promote the use of them? o The three levels of electricity planning are interconnected and decisions at one level can affect decisions at other levels. For example, if there is a need in a region and the best way to address the need is through generation, then that generation (including biomass) can also provide value to the bulk or distribution systems. Depending on the type of plant and where it is located, it is possible to provide supply to the regional network which would then tie in to the northwest bulk system. • The Greenstone mine is currently going through an environmental assessment process and they are discussing using gas generation. Is there any infrastructure or plans to service that area? o The development of the Greenstone-Marathon IRRP began in early 2015 and Local Advisory Committees were established for the area. Early on, the IESO was advised that the need in the area is urgent and that a plan was required as soon as possible. To address this, the IESO developed an Interim IRRP (released June 2015) that provided recommendations on how to connect the mining, pumping stations and saw mill projects in the near term. The IESO has spoken with the mining and gas company representatives and they are looking at installing generation instead of pursuing the transmission option. Ultimately, it is up to the proponents to decide which option they will pursue. The final Greenstone-Marathon IRRP is being released at the end of June 2016. As it relates to the Thunder Bay IRRP, the studies have assumed the Greenstone loads will be connected via transmission along line A4L served primarily by the Lakehead TS. • Is the unit running at the Thunder Bay Generating Station (GS) part of the 475WM of supply available in the area (slide 6)? Doesn't the contract end in 2019 and wouldn't you lose 150MW of supply in 2019? o The graph represents the capabilities of all generators in the area as well as the transformation capabilities of Lakehead TS. The Thunder Bay GS current contract only allows a certain amount of fuel and it doesn't have enough fuel to provide a reliable source of capacity for the area, so it does not contribute	

to the LMC. Therefore, Thunder Bay GS has an installed capacity of 150MW and it is part of the supply, but the value attributed to it is zero since due to its short supply of fuel, it is unable to run reliably when it is needed. • On March 10 there was a 15 hour power outage in Greenstone during cool temperatures because of the unreliability of that line. • How are the pipeline loads being divided between the west of Thunder Bay, Thunder Bay and Greenstone planning areas? o The plan for the pumping stations is to connect as many as possible to the electricity system. Where the stations are near transmission lines, it is easy to determine which region it will be in. For example, if the station is near a line west of Mackenzie TS it will be considered in the West of Thunder Bay plan, if it is around Lakehead TS to the Greenstone area then it will be included in the Thunder Bay plan, and if it is along the A4L, it will be included in the Greenstone plan. There are also pumping stations that are not near a transmission line where new circuits may need to be built and the station wouldn't fall into any one particular planning region. In this case, it may depend on which way electricity is flowing at the time that it is pumping. • How much of the Greenstone growth is from the pipeline (slide 6)? o One station is part of the Greenstone area growth. The top part of the graph (marked as pipeline conversion) represents the stations in the Thunder Bay area. There are several pumping stations that potentially could be converted in the Greenstone area. The most economic option for electricity supply to the pumping stations would include a new 230kV line to the Greenstone area. This would result in a lower demand as seen by the Thunder Bay 115kV subsystem, which supplies the existing 115kV line to the Greenstone area. • What is an auto-transformer? o An auto-transformer converts power from the bulk system voltage (230kV) to the regional transmission voltage (115kV) at which point it can be delivered to customers and Local Distribution Companies in the area. • Where is the R2LB line? o Hydro One: R2LB is a three terminal line that comes down from Pine Portage TS to Lakehead TS to Birch TS. There are two lines in parallel, one with a higher rating than the other because of some clearances (due to feeders underneath), but that will be fixed.	
Approaches to Meet Area Needs and/or Maintain LMC Margin *Presentation Summary: As context for the options discussion, a diagram (slide 9) was presented to the LAC members to illustrate the transmission and generation options to meet capacity needs in the Thunder Bay area. The existing East-West Tie takes electricity from the rest of the system (which has a projected surplus forecasted to the mid-2020s) and brings it into the northwest. With the expansion of the East-West Tie scheduled to be completed in 2020, there is sufficient capacity to meet the needs in the northwest. Once the electricity moves through the East-West Tie, some of the electricity supplies other loads and some supplies the Thunder Bay area through the Lakehead TS.* *<u>Transmission Options:</u>* *While there are currently no capacity limitations in the area, if load should grow under the high growth scenario, supply would be limited by the number of autotransformers at the Lakehead TS. This is because the amount of electricity that can be supplied by the existing two autotransformers isn't enough to meet the forecast need that may arise in the mid-2020s. The two transmission options, both of which permit utilization of grid resources via*	

the expanded East-West Tie, are: • *Install a third auto-transformer at Lakehead TS ($30M)* • *Install a new auto-transformer at Birch TS with a new 230kV line ($100M) – provides another supply point that could potentially enable further growth* *<u>Thunder Bay Generation Option:</u>* *While most of the capacity and energy needs can be met through the existing Lakehead TS, there are a few hours during the year where it may not be enough. In these situations, local supply could meet that need. If future need is met through local generation, it would need to be operating in advance in order to ramp between 0-40MW to meet the capacity shortage. Description of the Thunder Bay GS as an option:* • *Thunder Bay GS currently operates one 150MW unit on advance biomass that is shipped from Norway. The contract is set to expire in 2019.* • *Any further consideration of this asset on biomass will require a more certain and a more cost effective method of procuring fuel.* • *The facility has a minimum load point of approximately 25% of installed capacity, approximately 40MW, matching the size of the projected need. As this is the minimum capacity, there is no room to ramp between 0-40MW.* • *When compared to other peaking systems, the facility's ramp rate is slower. Any local generation solution would need to run in advance of the need so that it's ready to produce power when needed.* *A comparison was provided (slide 12) between the transmission and generation options taking in to consideration cost, operability and flexibility.* *<u>Other Supply Options:</u>* • *The Nipigon contract is approximately 40MW and is set to expire at the end of 2022; further operation is uncertain at this time.* • *Hydroelectric – based on current information, local hydro is not suitable to meet the potential need since Thunder Bay has peaking, not energy needs.* • *New Build – Whether powered by natural gas or biomass, a new facility would be fairly expensive; there is uncertainty surrounding fuel costs and availability.* *<u>Distributed Generation (DG) Options:</u>* *Over the past 10 years, FIT, microFIT, RESOP and HCI programs have resulted in over 27MW of installed DG in the Thunder Bay area and going forward, DG will continue to be developed through the FIT and microFIT programs. Any new generation contracted before the LMC is met will help defer the need; however, there are currently short circuit limitations at some of the transmission stations that would impose limits on the generation that can be installed on the distribution system. A lot of the generation procured from the FIT and microFIT programs is solar which is not effective in meeting peak loads in the area (night time in the winter). Water and bioenergy DG might be better fits for meeting needs, but it would depend on the type of generation.* *<u>Conservation and Demand Management (CDM) Options:</u>* *CDM plays a key role in maximizing existing assets and offsetting demand growth which could allow for the deferment of infrastructure needs. Conservation is best suited to a need where load growth is slow and the need is far in the future, thereby allowing the additional time needed to get conservation results. The load forecast already includes the conservation targets set out in the provincial Long-Term Energy Plan (LTEP) and the LDC's Conservation Plan to meet their conservation targets for 2020. Given these factors, additional CDM may delay, but it will not eliminate area needs.*	

<u>Demand Response (DR) Options:</u> *DR plays a role in reducing load at peak by triggering customers who have flexibility in their load to decrease load at times of system need. Currently the DR program is for meeting provincial needs, but if DR is to be an option for regional needs, then a different type of trigger mechanism is needed. The IESO is currently undertaking pilot programs for another regional plan looking at a regional or local DR program. At the moment, Thunder Bay peak does not match the provincial peak; therefore the current DR program design does not help address capacity needs in the Thunder Bay area.* *<u>Summary of Options:</u>* *Transmission is the most suitable option to meet the potential need due to its relatively low cost and the nature of the need. The short lead time of 3 years will allow the IESO to monitor load growth and commit resources when needed. Concurrent with this, development of transmission west of Thunder Bay will be monitored for opportunities to coordinate activities between the two plans as this could have additional benefits to the Thunder Bay system. Generation options are less suitable given their costs and performance capabilities in relation to the future needs. CDM has been incorporated into the load forecast and economic demand management activities like DR will continue to be explored in the Thunder Bay area, to help defer infrastructure investments.* **Questions and Feedback from LAC members on the transmission options:** • With respect to the East-West Tie, would it be better to put in a higher voltage line instead of a new line? There are lots of lines coming into Thunder Bay. o The new East-West Tie line is based on the existing line which is a double circuit 230kV line and it will add about 450MW of additional capacity. A higher voltage line (e.g. 500 kV) would not provide further benefit since it would become the largest contingency (i.e., after the loss of the 500 kV line, you're left with a 230 kV line). There may be value to twinning the line. The current load in the northwest is about 750MW and the line supplies almost half the load, with an additional 600MW from hydro. The Tie serves two purposes – it provides capacity for the northwest and it allows excessive power to flow toward the northeast without restriction. Currently, there is still a bottleneck from the northeast to Toronto, but once that is resolved there will be a free running "highway" all the way from the northwest down to Toronto. • The (transmission) solution seems to be based on more centralized generation in southern Ontario as opposed to a distributed generation system, so we are going to be relying more and more on a generator that is a thousand miles away to meet our needs. This seems different from what I have heard about generation and seems like a very short-term thought pattern. o The vast majority of demand in the northwest is currently served by hydro generation. To meet future needs, we are looking at the few hours of the year when demand spikes and the rivers are running dry. In these situations, the bulk transmission system can assist in meeting this need in a cost-effective way. In Ontario, there is no incremental generation being built in the south to serve the northwest – we have built enough to meet system adequacy in the south and this can help meet needs without building more resources. • Does the new auto transformer at Birch TS only help the City of Thunder Bay or does it help the Thunder Bay region? o It helps the entire region. While the costs of installing an autotransformer at Birch TS are higher, the option was added to explore possible synergies with the west of Thunder Bay bulk reinforcement project. While that route is not yet known, we may be able to take advantage of that line to create a second	

supply point at Birch TS. This is looking at the longer term.

- Who plays the role of the coordinator between Hydro One and the private developer for the East-West Tie? IESO? OEB?
  - The IESO looks after provincial and regional planning. However, broader system planning is part of the government's Long-Term Energy Plan. It sets the general policy direction on electricity matters including items such as resources and conservation. The next version of the LTEP will be developed at the end of this year and the government will be consulting across the province. The IESO is providing input into the development of the plan and will be asked to prepare an implementation plan based on the LTEP.
- Since we last met a very devastating thing happened in Fort McMurray. One of my concerns is the proximity of the existing East-West Tie to the new line. Is fire damage a possibility?
  - On the resource side, the northwest has over 600MW of hydro, and 200MW of interconnection with Minnesota and Manitoba that can be drawn upon in an emergency. There have been cases that single circuits on wood poles were knocked down by a forest fire, but that would not be a problem on the East-West Tie as they are steel lattice towers. In 2011 there was an ice storm that knocked down 14 towers and Hydro One quickly built a bypass on wood poles to keep the connection between the northwest and the northeast.
- I believe the East-West Tie averaged 12 outages per year from 2009 to 2014. During one outage, the line near Schreiber was down for 16 days. They might have bypassed it but that didn't happen overnight.
  - The bypass was built quickly. Generally, outages of the East-West Tie are not causing customer outages. Local generation, the connections to Manitoba and Minnesota all prevent blackouts and customer outages due to the East-West Tie going down. Now with double circuits, the likelihood of both circuits going down is very low.

Questions and Feedback from LAC members on the generation options:

- Is gas generation off the table with the recently proposed Ontario Climate Change Action Plan? Will electricity generation from natural gas be restricted? Since Thunder Bay GS is a provincial asset, I suspect that the government is not going to allow that it be changed to natural gas.
  - Gas-fired generation is less advantageous than previously. We still don't have a plan that says there is no gas. For the purposes of today's discussion, references to Thunder Bay GS are biomass plant.
- What is the "slow relative ramp" for Thunder Bay GS?
  - It is not slow in absolute terms but slower in terms of newer systems because of the nature of the technology. Thunder Bay GS is a ranking system where there is a boiler to heat up water and create steam that is then pushed through a steam turbine, versus having a gas turbine or an engine that runs off diesel. It is slow versus other dispatchable systems.
- Was Thunder Bay GS brought up as an option for comparisons sake?
  - This option is presented because of the level of interest. A number of options eliminate themselves based on operability characteristics, relative capital costs, the nature of the need etc. The costs in relation to other options make them uneconomic or not feasible.
- Forecasting is what the IESO does - forecasting loads and predicting needs. Based on this, you should be able to determine when a facility like Thunder Bay GS is going to be needed in enough time to allow them to be up and running when they are needed. Why is this a negative?

- There are different types of generators that will ramp up faster than others. When you look at loads throughout the day you can see how quickly things can change and we are seeing that more so today then a number of years ago. When you are looking at generating capability then ramp rate is one of the things that is considered. Compared to other options that may be available, the ramp rate might not be as good. Ramp rates, start-up costs, minimum run time – these are all operating characteristics that help make a decision.

- For the generation option, is it the IESO's standpoint that you're looking for one source, multiple sources, or does this matter?
  - There are several options. It could be a single facility with multiple generators in it or a single large generator. The timing of the need around late 2020's, allows enough time to get the most out of conservation, to see how the localized DR pilots are doing and try to defer the need as much as possible. The decision does not need to be made right away.
- Slide 12 is negative towards Thunder Bay GS. The worst case scenario is presented and that's not really fair. You're saying slow ramp rate, slow start up and that is only when the unit is cold. If the unit is hot, then it's a quick start and it's a quick ramp rate. Your data is correct for one set of circumstances and I think it might be set up purposely to be bias for the transmission. It's not a true representation.
  - These are the characteristics under a certain set of circumstances but these are the circumstances we are forecasting. With respect to the load forecast scenario, the 40MW is a very optimistic need.
- When the East-West Tie went down for 16 days in Schreiber, the generating station was operating 24/7 full load for that period of time. This represents a need for a rapid capability unit in the northwest.
  - With existing load levels and connections to Manitoba and Minnesota, you will not need generation to run 24 hrs/day in that situation.
- Thunder Bay GS provides security that is needed. Should something happen, you can mobilize an alternative source of power that is here and available. It is a matter of what you want to pay to have that insurance policy for the future. Fort McMurray has taught us that anything can happen. There are tornados in the north, and if one took out the line, we might need to able to provide power in the local area or even out to the broader regions. We need to keep looking at it – you have the asset and it's not something you need to throw away.
- Are there any other plants in North America that are being developed with advanced biomass? I know that one of the issues is the supply of the fuel, so what's the forecast for that?
  - Ontario Power Generation (OPG) has indicated that within North America they are leading the way and lots of people are visiting their biomass facility to look at what they have been doing especially since the United States is looking at the retirement of some of their coal plants.
- There is a proposal in the Armstrong area for a biomass generator that will take over for the diesel generators, approximately 3MW. That is the perfect application for a local load centre generation. Is the IESO looking for more of those types of low generation biomass units that are quick operating assets and can be placed close to a load centre? Does this impact the orange zone? It prevents having to build or upgrade long transmission lines.
  - Whitesand First Nations had a proposal for a biomass generator as well as a pellet plant. Because of the government's policy to reduce diesel generation in remote First Nations communities, they sent a directive to the IESO to arrange a power purchase agreement with Whitesand First Nations but they will remain off grid and not influence the orange zone.

- For the foreseeable future, there is abundant clean and low cost generation. We have procured a lot of renewable generation over the past few years and now the idea of generating on top of that with local biomass is not the most economic at this time because there is enough on the system. We are not building that much transmission with some exceptions in the northwest such as the line to Pickle Lake.

Questions and Feedback from LAC members on Distributed Generation, Conservation and Demand Response:

- How can FIT be an option for the future if the northwest is an orange zone?
  - Projects under the 500kW in size can still connect.
- Do Time-of-Use rates contribute to making a false peak? This could probably be better managed by looking at the rates to push different peak times.
  - It is perhaps not the TOU that is affecting peak as much as the different programs in place to incent industrial customers to consume power at non-peak times. Through the DR pilot program, we hope to learn more about the triggers and characteristics of the load that would be ideal for this. This would only be for a few hours during the year.
- On slide 14, all but three projects are solar. This seems to go against what was said about solar not being effective in Thunder Bay since peak loads occur in the evenings. Why is the IESO encouraging ineffective generation?
  - Although these projects are likely not contributing to reduce the demand locally since the peak occurs overnight in winter, these projects contribute to reducing the provincial demand as the peak occurs in the summer during the hottest days of the year and typically that's when the water dries up in the northwest. Also, the FIT and microFIT are provincial procurement programs.

General Questions and Feedback from the LAC members:

- There is a local company looking at making glass for solar panels – 68 MW load per line (eventually 4 lines). Can the company work with OPG on this? This may eliminate the need to bring supply from Norway.
  - IESO needs to contract on behalf of the rate payers of Ontario and needs to consider whether other resources can be used to supply the load. From the perspective of the IESO, there is enough capacity on the system to supply any load in the area. If there is a desire to have generation contracted, it is up to the external parties. For large loads, it is important to contact the IESO to start the connection process.
- If the northwest is contributing supply to southern Ontario which is summer peaking, then the northwest should never be an orange zone or maybe just a winter orange zone.
  - The orange zone refers to the Large Renewable Procurement whereas the distributed generation slide refers to FIT which is projects less than 500kW. An issue arises if you procure a large project in the north (i.e., 100MW wind farm) where the generated power can either be consumed by a customer or it can be transferred out of the region through the East-West Tie. If there are not enough customers at the time and the East-West Tie is congested, the new wind turbine needs to be turned off because there is nowhere for the power to go, even though the turbines were procured with ratepayer money. With smaller projects like FIT (under 500 kW) and microFIT (under 10kW) this is generally not an issue. These are typically solar projects which generate the most power in the summer when the rivers aren't running as strongly and therefore not as much power is flowing along the East-West Tie.

• If the line is truly congested then it's not getting to where it supposed to go, regardless of the size of project. o If the lines are congested and generation is higher than demand, then something has to be curtailed. For each large renewable procurement, a new set of transmission and distribution availability tables is prepared that shows the availability for each line across the province. • Right now the whole north, not just the northwest is an orange zone for LRP. o The northwest has been at zero capacity for a number of years and the capacity in the northeast became zero on the last Large Renewable Procurement and will stay zero unless something happens. The IESO will endeavour to update the tables more often. • When does a decision need to be made on the solution for Thunder Bay? o Not for a while. Typically it takes three years to install a new auto transformer and some solutions can be done quicker. There is time to explore the potential for a more localized DR program which isn't available yet, but could be a good approach in the future. With regards to the timing of the regional plans, they are renewed every five years or sooner. This Thunder Bay regional plan will be released towards the end of 2016 which means that the next regional plan will come out towards the end of 2021 at the latest. The IESO will be monitoring the developments in the area during that time and the next regional plan can be triggered earlier if needed.	
Public Questions or Feedback: • There were no public questions or feedback.	
Next Steps: • Another meeting of the Thunder Bay LAC will be scheduled to discuss the draft plan recommendations prior to publication of the Thunder Bay IRRP.	

E.3 Meeting Summary for Thunder Bay Local Advisory Meeting #3

Meeting Summary	
Date:	Wednesday, November 2, 2016
Location:	Thunder Bay, ON
Subject:	Thunder Bay Local Advisory Committee Meeting #4
Attendees:	**Committee Members in Attendance** Ralph Bullough Ray Quinn Erik Ross Duff Stewart Jim Vezina **Hydro One (via webinar)** Hamid Hamadanizadeh **IESO** Stephanie Aldersley Bob Chow Luisa Da Rocha Alex Merrick **Thunder Bay Hydro** Rob Mace Tim Wilson Karla Bailey
LAC Meeting Materials:	http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/Thunder-Bay.aspx

Key Topics	Follow-up Actions
Opening Remarks and Roundtable Introductions • Ms. Da Rocha welcomed everyone and reviewed the meeting agenda • Roundtable introductions were made	
Review of LAC Meeting #3 Summary and Follow-Up Actions • The summary from LAC meeting #3 was reviewed with the committee • It was noted that there was a change on page 4 of the draft meeting summary for the question "Where is the R2LB line?" The answer should reference Pine Portage, not, Point Portage. This correction will be made prior to posting.	☐ Meeting summary to be corrected and posted on Thunder Bay LAC webpage
Discussion of LAC Inquiries Received Since the Last Meeting • No inquiries were received from LAC members since the last meeting	

Recap of Thunder Bay Planning Process *Presentation Summary: The regional planning process started about two years ago following the release of the Northwest Ontario Scoping Report that identified Thunder Bay as requiring coordinated regional planning. A Working Group was formed to develop an Integrated Regional Resource Plan (IRRP) and the group created a load forecast that was shared with municipalities and communities at meetings held in March 2015. A Local Advisory Committee (LAC) was formed with the first two meetings held in November 2015 and March 2016. In spring 2016, the Working Group revised the load forecast based on newly available information and presented a new load forecast along with options to address needs at the third LAC meeting in June 2016. The Working Group has since been finalizing the results of the needs assessment, and drafting the IRRP.*	
Thunder Bay IRRP – Key Study Assumptions, Needs and Recommendations *Presentation Summary: To assess the adequacy of electricity supply to the Thunder Bay sub-system, the Working Group applied the Ontario Resource and Transmission Assessment Criteria (ORTAC) over a 20-year period and under three different load forecast scenarios – high, medium and low. The forecast for the area includes growth in the LDC service territory, load from direct-connected industrial customers as well as potential new mining loads and the pipeline conversion project. The scenarios also consider the impact of the Greenstone sub-system on the Thunder Bay area and assume the most impactful scenario where circuit A4L is rebuilt to allow up to 60MW of future load to connect. Further information on circuit A4L is available in the Greenstone/Marathon IRRP: http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/Northwest-Ontario/Greenstone-Marathon.aspx* *Overall, the needs assessment found that the Thunder Bay system is adequate today and can accommodate over 150MW of load growth before additional supply is required.* *<u>Near-Term Needs:</u>* *There is one recommended near-term action to upgrade a section of circuit R2LB between Lakehead Transformer Station (TS) and Birch TS as it has a lower rating and could reach capacity by the mid-2020s under the high growth scenario. To address this, Hydro One will upgrade the circuit by spring 2017 by modifying the feeder that goes under the circuit, or some other form of improvement, to bring the line to the same level as other circuits. (Update note: This line work has been completed as of Q4 2016). No other near-term actions are recommended in the plan.* *<u>Long-Term Needs:</u>* *The plan identifies two potential long-term needs under the high growth scenario. There is a need for potential supply capacity for the Thunder Bay 115kV system by 2030 under a high growth scenario and with a rebuild of A4L in Greenstone. Options were investigated to address this need including transmission reinforcement, generation and other options such*	

as demand response, distributed energy resources, and conservation. The options were reviewed and discussed in more depth at previous LAC meetings, where it was also mentioned that preliminary results show that the addition of a third autotransformer at the Lakehead TS is the lowest cost option. It was noted that the existing autotransformers at Lakehead TS were replaced this fall with further work to take place in the spring. *Another potential long-term need is for transformer station capacity at the Port Arthur TS by 2033. Capacity at the station is limited by low voltage equipment and if upgraded, the capacity could increase by 4MW and delay the need beyond the planning period. This work could likely be done at a low cost if coordinated with sustainment activities. If load growth should exceed the forecast, there are other options to further increase capacity.* *A summary was provided of the recommended actions to be included in the report (slide 8):* • *Near-term need to upgrade circuit R2LB – Hydro One to address by spring 2017 (Update note: this line work has been completed as of Q4 2016)* • *Potential long-term need for capacity on Thunder Bay 115 kV system – no action required now* • *Potential long-term need for capacity at Port Arthur TS - no action required now* *For the long-term needs, there is time to monitor load, study options, and revisit the needs in subsequent planning cycles. If faster growth is noticed, the planning process can be restarted at any point. Annual updates will be provided on IESO website.* *Two other areas of interest identified and explored further in the study are power quality and 230kV voltage regulation. See slide 9 for additional details.* *It was noted by the Working Group that the plan should recognize the commitments in the Climate Change Action Plan.* **Questions and Feedback from the LAC members:** • What is a shunt reactor (slide 9)? o They are devices that reduce voltage; they perform the opposite function of capacitors that increase voltage. In the north, there is a tendency for voltage to go high during equipment outages because of lighter loads. At Lakehead TS, the loss of the two transformers, also leads to the loss of the control devices resulting in a high voltage on the 230kV line. Shunt reactors are being installed as a result of the East-West Tie work. They are also installed in Dryden and Marathon so they are not unique at this location. • Is the Working Group study on power quality available? o Yes, a summary with be included in the report and the detailed results will be included in the plan appendices. • For installed renewable energy projects, what happens when the contract ends? o It is not uncommon in the lease arrangements for renewable projects to include provisions for the project owner to remove and remediate the lands. This issue is not unique to renewables and is also seen with non-utility and other generators.	
Major Bulk Transmission Projects in the Northwest *Presentation Summary: Four bulk transmission projects were reviewed including the East-West Tie, Line to Pickle Lake, the Remote Community Connection Plan and the Northwest Bulk Line. The first three projects have all received orders in council, and for the northwest*	

bulk transmission line, while Hydro One has not official launched the project, the initial studies have been started. **Questions and Feedback from LAC members:** • Is the new Line to Pickle Lake a ring bus system with the old line? o The recommended configuration will have an open point on the east side of Ear Falls. All of the customers on E1C will be supplied from the new line to Pickle Lake, but it will normally be disconnected at Ear Falls. There will be options in the event of an outage to re-supply the area.	
Next Steps Following the LAC meeting, an email will be sent to the members inviting feedback on the draft recommendations for an additional two weeks. The Thunder Bay plan is scheduled to be posted on December 16, 2016 to the dedicated Thunder Bay regional planning webpage on the IESO website. Annual updates on the plan will also be posted to this webpage.	☐ Email members inviting feedback for an additional two weeks
Future Role of the LAC The role of the LAC is to provide advice and recommendations in the development of the regional plan. With the upcoming release of the plan, the committee was asked for their feedback whether they would like to continue to meet and how often. It was noted that the plan will be revisited in five years at the latest. **Questions and Feedback from LAC members:** • Meeting once a year between plans is sufficient. The meeting frequency should increase once the next planning cycle begins. There was agreement with the committee members in attendance that the LAC would continue to meet on a yearly basis to discuss the annual plan update and to be provided with an update on the bulk projects. The impacts of the LTEP and Climate Change Action Plan on the regional plan are to be part of this update.	☐ The decision for the LAC to meet once a year following the posting of the plan to be included in the email to members for additional feedback
Public Questions or Feedback: • In relation to the major transmission projects map (slide 10), there are lines that are not identified in the Greenstone area to serve the Greenstone Gold Mine and address reliability in the area. The solutions shown on the map seem to negate the needs in Greenstone. The Greenstone LAC has recommended going straight to a 230kV system and this is not identified on the map. o The purpose of the map is to show the committed priority projects included in the 2013 LTEP as they relate to the Thunder Bay regional plan. The map shows the committed projects, but does not identify all projects. The Thunder Bay plan assumes the most impactful scenario (where Thunder Bay needs to supply 60 MW to Greenstone), however it does not make a statement on the outcome of the Greenstone-Marathon plan.	
Meeting Adjournment Committee members were thanked for their contributions to the development of the Thunder Bay plan and the meeting was concluded.	

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Key Topics	Follow-up Actions
Opening Remarks and Roundtable Introductions • Ms. Da Rocha welcomed everyone and reviewed the meeting agenda • Roundtable introductions were made	
Review of LAC Meeting #3 Summary and Follow-Up Actions • The summary from LAC meeting #3 was reviewed with the committee • It was noted that there was a change on page 4 of the draft meeting summary for the question "Where is the R2LB line?" The answer should reference Pine Portage, not, Point Portage. This correction will be made prior to posting.	☐ Meeting summary to be corrected and posted on Thunder Bay LAC webpage
Discussion of LAC Inquiries Received Since the Last Meeting • No inquiries were received from LAC members since the last meeting.	

Recap of Thunder Bay Planning Process *Presentation Summary: The regional planning process started about two years ago following the release of the Northwest Ontario Scoping Report that identified Thunder Bay as requiring coordinated regional planning. A Working Group was formed to develop an Integrated Regional Resource Plan (IRRP) and the group created a load forecast that was shared with municipalities and communities at meetings held in March 2015. A Local Advisory Committee (LAC) was formed with the first two meetings held in November 2015 and March 2016. In spring 2016, the Working Group revised the load forecast based on newly available information and presented a new load forecast along with options to address needs at the third LAC meeting in June 2016. The Working Group has since been finalizing the results of the needs assessment, and drafting the IRRP.*	
Thunder Bay IRRP – Key Study Assumptions, Needs and Recommendations *Presentation Summary: To assess the adequacy of electricity supply to the Thunder Bay sub-system, the Working Group applied the Ontario Resource and Transmission Assessment Criteria (ORTAC) over a 20-year period and under three different load forecast scenarios – high, medium and low. The forecast for the area includes growth in the LDC service territory, load from direct-connected industrial customers as well as potential new mining loads and the pipeline conversion project. The scenarios also consider the impact of the Greenstone sub-system on the Thunder Bay area and assume the most impactful scenario where circuit A4L is rebuilt to allow up to 60MW of future load to connect. Further information on circuit A4L is available in the Greenstone/Marathon IRRP: http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/Northwest-Ontario/Greenstone-Marathon.aspx* *Overall, the needs assessment found that the Thunder Bay system is adequate today and can accommodate over 150MW of load growth before additional supply is required.* *<u>Near-Term Needs:</u>* *There is one recommended near-term action to upgrade a section of circuit R2LB between Lakehead Transformer Station (TS) and Birch TS as it has a lower rating and could reach capacity by the mid-2020s under the high growth scenario. To address this, Hydro One will upgrade the circuit by spring 2017 by modifying the feeder that goes under the circuit, or some other form of improvement, to bring the line to the same level as other circuits. (Update note: This line work has been completed as of Q4 2016). No other near-term actions are recommended in the plan.* *<u>Long-Term Needs:</u>* *The plan identifies two potential long-term needs under the high growth scenario. There is a need for potential supply capacity for the Thunder Bay 115kV system by 2030 under a high growth scenario and with a rebuild of A4L in Greenstone. Options were investigated to address this need including transmission reinforcement, generation and other options such as demand response, distributed energy resources, and conservation. The options were reviewed and discussed in more depth at previous LAC meetings, where it was also mentioned that preliminary results show that the addition of a third autotransformer at the Lakehead TS is the lowest cost option. It was noted that the existing autotransformers at Lakehead TS were replaced this fall with further work to take place in the spring.*	

Another potential long-term need is for transformer station capacity at the Port Arthur TS by 2033. Capacity at the station is limited by low voltage equipment and if upgraded, the capacity could increase by 4MW and delay the need beyond the planning period. This work could likely be done at a low cost if coordinated with sustainment activities. If load growth should exceed the forecast, there are other options to further increase capacity. *A summary was provided of the recommended actions to be included in the report (slide 8):* • *Near-term need to upgrade circuit R2LB – Hydro One to address by spring 2017 (Update note: this line work has been completed as of Q4 2016)* • *Potential long-term need for capacity on Thunder Bay 115 kV system – no action required now* • *Potential long-term need for capacity at Port Arthur TS - no action required now* *For the long-term needs, there is time to monitor load, study options, and revisit the needs in subsequent planning cycles. If faster growth is noticed, the planning process can be restarted at any point. Annual updates will be provided on IESO website.* *Two other areas of interest identified and explored further in the study are power quality and 230kV voltage regulation. See slide 9 for additional details.* *It was noted by the Working Group that the plan should recognize the commitments in the Climate Change Action Plan.* **Questions and Feedback from the LAC members:** • What is a shunt reactor (slide 9)? o They are devices that reduce voltage; they perform the opposite function of capacitors that increase voltage. In the north, there is a tendency for voltage to go high during equipment outages because of lighter loads. At Lakehead TS, the loss of the two transformers, also leads to the loss of the control devices resulting in a high voltage on the 230kV line. Shunt reactors are being installed as a result of the East-West Tie work. They are also installed in Dryden and Marathon so they are not unique at this location. • Is the Working Group study on power quality available? o Yes, a summary with be included in the report and the detailed results will be included in the plan appendices. • For installed renewable energy projects, what happens when the contract ends? o It is not uncommon in the lease arrangements for renewable projects to include provisions for the project owner to remove and remediate the lands. This issue is not unique to renewables and is also seen with non-utility and other generators.	
Major Bulk Transmission Projects in the Northwest *Presentation Summary: Four bulk transmission projects were reviewed including the East-West Tie, Line to Pickle Lake, the Remote Community Connection Plan and the Northwest Bulk Line. The first three projects have all received orders in council, and for the northwest bulk transmission line, while Hydro One has not official launched the project, the initial studies have been started.*	

Questions and Feedback from LAC members: • Is the new Line to Pickle Lake a ring bus system with the old line? o The recommended configuration will have an open point on the east side of Ear Falls. All of the customers on E1C will be supplied from the new line to Pickle Lake, but it will normally be disconnected at Ear Falls. There will be options in the event of an outage to re-supply the area.	
Next Steps Following the LAC meeting, an email will be sent to the members inviting feedback on the draft recommendations for an additional two weeks. The Thunder Bay plan is scheduled to be posted on December 16, 2016 to the dedicated Thunder Bay regional planning webpage on the IESO website. Annual updates on the plan will also be posted to this webpage.	☐ Email members inviting feedback for an additional two weeks
Future Role of the LAC The role of the LAC is to provide advice and recommendations in the development of the regional plan. With the upcoming release of the plan, the committee was asked for their feedback whether they would like to continue to meet and how often. It was noted that the plan will be revisited in five years at the latest. **Questions and Feedback from LAC members:** • Meeting once a year between plans is sufficient. The meeting frequency should increase once the next planning cycle begins. There was agreement with the committee members in attendance that the LAC would continue to meet on a yearly basis to discuss the annual plan update and to be provided with an update on the bulk projects. The impacts of the LTEP and Climate Change Action Plan on the regional plan are to be part of this update.	☐ The decision for the LAC to meet once a year following the posting of the plan to be included in the email to members for additional feedback
Public Questions or Feedback: • In relation to the major transmission projects map (slide 10), there are lines that are not identified in the Greenstone area to serve the Greenstone Gold Mine and address reliability in the area. The solutions shown on the map seem to negate the needs in Greenstone. The Greenstone LAC has recommended going straight to a 230kV system and this is not identified on the map. o The purpose of the map is to show the committed priority projects included in the 2013 LTEP as they relate to the Thunder Bay regional plan. The map shows the committed projects, but does not identify all projects. The Thunder Bay plan assumes the most impactful scenario (where Thunder Bay needs to supply 60 MW to Greenstone), however it does not make a statement on the outcome of the Greenstone-Marathon plan.	
Meeting Adjournment Committee members were thanked for their contributions to the development of the Thunder Bay plan and the meeting was concluded.	