NPCC
2012 Ontario Comprehensive Review of Resource Adequacy

Covering the Ontario Area

for the period 2013 to 2017

Approved by the RCC
November 27, 2012

November 27, 2012

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1 EXECUTIVE SUMMARY

1.1 Major Findings

The Independent Electricity System Operator (IESO) submits this assessment of resource adequacy for the Ontario Area to comply with the Reliability Assessment Program established by the Northeast Power Coordinating Council (NPCC). This 2012 Comprehensive Review of Resource Adequacy covers the study period from 2013 through 2017, and supersedes the review conducted in 2009. The guidelines for the review are specified in Appendix D of the NPCC Regional Reliability Reference Directory #1, "*Guidelines for Area Review of Resource Adequacy*" (Original document: December 1, 2009).

The IESO determined Ontario's level of reliability using the Multi-Area Reliability Simulation (MARS) program.

Since the last comprehensive review in 2009, about 2,400 MW of generation capacity has been added in Ontario, and 3,200 MW of coal capacity has been shutdown. Capacity additions include about 1,600 MW of gas-fired capacity, more than 600 MW of wind, 70 MW of hydroelectric, 50 MW of biomass and 20 MW of nuclear. In addition, future generating resource capacity additions of 7,000 MW are under construction or planned to come into service from now till 2017.

There are eight more coal units across three facilities, totalling 3,300 MW, in the province that will be phased out by 2014. In the Northwest zone, the conversion of Atikokan to burn biomass is underway. Conversion of some or all of the six southern Ontario coal units is being evaluated against other supply alternatives.

This Comprehensive Review identifies changes in assumptions from the 2009 Comprehensive Review, including changes to facilities and system conditions, generation resources availability, load forecast, and electricity sector regulations..

This 2012 Comprehensive Review indicates that Ontario will be able to meet the NPCC resource adequacy criterion that requires an LOLE (loss of load expectation) value of no more than 0.1 days/year for all years from 2013 to 2017. New generation that is expected to come into service together with the general decline in forecast demand arising from conservation and embedded generation are expected to maintain the reliability of the Ontario power system as the coal units are removed from service.

1.2 Major Assumptions and Results

This review covers the period from 2013 to 2017 inclusive. Major assumptions are summarized in Table 1.1 below:

Table 1.1 Major Assumptions

Assumption	Description
Adequacy Criterion	NPCC Loss Of Load Expectation (LOLE) requirement of not more than 0.1 days/year
Reliability Model	GE's MARS program
Load Model	8,760 hourly loads with forecast uncertainty factors
Energy Demand Growth Rate	Median Demand Growth: about -2.3% per annum High Demand Growth: about -1.6 % per annum
Generating Capacity Additions	7,000 MW by the end of 2017
Generating Capacity Retirements	About 3,300 MW of coal-fired generation is in operation. Coal generation will cease by 2014. The coal to biomass conversion at the Atikokan Generating Station is expected to take place by 2013Q4.
Internal and Interconnection Transmission Constraints	Based on IESO normal system operating security limits
Tie Benefits	Expected coincident import capability of approximately 5,200 MW with all the transmission elements in service. For all study years, no interconnection assistance was required to meet the LOLE criterion.
Emergency Operating Procedures	Initial runs had no EOPs modeled An additional run was modeled with EOPs for 2015 when LOLE of 0.1 days/year could not be achieved without EOPs
Unit Availability	Planned outages modeled: 2013 outages are based on planned outage submissions from market participants. 2014 to 2017 outages are based on forecast Planned Outage Factor (POF) from market participants and/or the Generic Outage Plan derived from historic outage patterns of existing units. Forced outages modeled: Based on Equivalent Forced Outage Rate (EFOR) derived from five-year history of actual forced outages. Units with insufficient historical data are based on forecast EFOR from market participants.
Conservation, Demand Management and Embedded Generation	Conservation: Up to 2,136 MW by 2017 Demand Management: Up to 1,673 MW by 2017 Embedded Generation: Up to 3,200 MW by 2017

There were two different sets of study conditions that the IESO established for modeling in MARS. In the first set of MARS runs, the calculations are performed with the assumptions listed above, without the use of any emergency operating procedures (EOPs). These resources include all existing units and projects under contract, as well as units procured for contracts by the OPA (Ontario Power Authority) as directed by the Ministry of Energy. If the LOLE criterion could not be met under the first study set, the second set of MARS runs are performed with the assumptions listed above, and additional use of EOPs. MARS results for the median and high demand growth scenarios are presented in Table 1.2.

The initial set of runs under the **median demand growth** forecast shows that Ontario would meet the LOLE criterion for all years of the study period. For all calendar years, only the first set of MARS runs was required to achieve the LOLE criterion of 0.1 days/year. This was achieved without utilizing any EOPs or interconnection assistance.

Under the **high demand growth** forecast assumption, Ontario would meet the LOLE criterion for all years of the study period. For the calendar year 2015, utilization of EOPs was required to meet the LOLE criterion. For all the other calendar years, the LOLE criterion was achieved without utilizing the EOPs. For all calendar years, interconnection assistance was not required to meet the LOLE criterion.

The study results under the median and high demand forecast are summarized in Table 1.2.

Table 1.2 Annual LOLE Values, Median and High Demand Forecast

Scenario	EOPs	Additional Resources (MW)	LOLE [days/year]				
			2013	2014	2015	2016	2017
Median	No	0	0.002	0.006	0.041	0.001	0.001
High	No	0	0.008	0.039	0.247	0.042	0.038
High	Yes	0	-	-	0.074	-	-

- End of Section -

2 TABLE OF CONTENTS

2.1 List of Tables

2.2 List of Figures

3 INTRODUCTION

This report is the comprehensive area review of resource adequacy for Ontario, prepared by the Independent Electricity System Operator and submitted to the Northeast Power Coordinating Council in accordance with Appendix D of the NPCC Regional Reliability Reference Directory #1, "*Guidelines for Area Review of Resource Adequacy*" (Original document: December 1, 2009).

The IESO is a non-profit, regulated corporation without share capital established by the Ontario Electricity Act 1998, with its Directors appointed by the government. It is responsible for the day-to-day operation of Ontario's electricity system, and is responsible for enabling, administering and operating the competitive wholesale energy markets for the province.

The information presented in this 2012 Comprehensive Review of resource adequacy covers the forecast period from 2013 through 2017.

3.1 Reference to Most Recent NPCC Comprehensive Review

The previous Comprehensive Review was submitted at the September 2009 meeting of the Reliability Coordinating Committee. Comparisons between this review and the September 2009, "IESO 2009 Comprehensive Review of Ontario Resource Adequacy for the period 2010 to 2014" are included in this report.

3.2 Comparison of This Review and Previous Review

3.2.1 Demand Forecast

The forecast of demand contains two scenarios; a median demand growth and high demand growth. The seasonal peak demand forecasts for this 2012 review are presented in Tables 3.1 and 3.2. Figure 3.1 compares the peak demand forecasts of the 2012 and the 2009 reviews.

Since the 2009 review, the economy has not grown out of the recession as strongly as expected. The global economy continues to be hampered by high levels of debt and unemployment which undermine both business and consumer confidence. Although most economies have rebounded from the recession many have not surpassed their pre-recession peaks. Ontario's export oriented economy has not been immune to these global headwinds. Over the forecast, the pace of economic expansion is expected to be low by historical standards.

Modest economic expansion combined with population growth will not be sufficient to offset the downward pressures from conservation, embedded generation and price effects[1]. The net results will be an overall decline in both energy and peak demand. The mix of embedded generation and the conservation programs composition will have differing impacts on the seasonal peaks and overall energy demand.

Under the median demand growth scenario both seasonal peaks and overall electricity demand is forecast to decline. Summer peaks will decline due to large investments in embedded solar capacity and winter peaks will decline as conservation programs and legislation drive lighting savings. Energy demand will also decline as conservation, embedded generation and price impacts all work to off-set increases from economic activity and population growth.

Under the high demand growth scenario, the seasonal peaks and overall electricity demand are expected to be higher than in the medium scenario with the major difference coming from higher cooling loads driven by residential and commercial growth. The assumptions for prices, conservation and embedded generation remain the same so the higher growth moderates the peak and energy declines over the forecast. Peaks and electricity demand are still expected to decline but at a much lower pace.

Compared to the 2009 forecast overall electricity demand is much lower due to the moderate economic recovery and underlying structural change. The peak demands are similar in the medium scenario as they are driven by the building stock and weather conditions which are not vastly different from 2009. However, the peaks under the High Growth scenario are much lower in 2012 as the economic potential has been both diminished and delayed by the slow recovery.

Although point forecasts are presented for both the median and high growth scenarios, each scenario has an associated "uncertainty" distribution which recognizes the variability of demand due to weather volatility.

Both demand forecast scenarios vary from the previous review due to the inclusion of actual data. As mentioned earlier the economic recovery has been disappointing by historical standards. This means that the total electricity consumption is at levels lower than in previously expected.

Table 3.1 Comparison of Demand Forecasts: Normal Weather Summer Peak (MW)

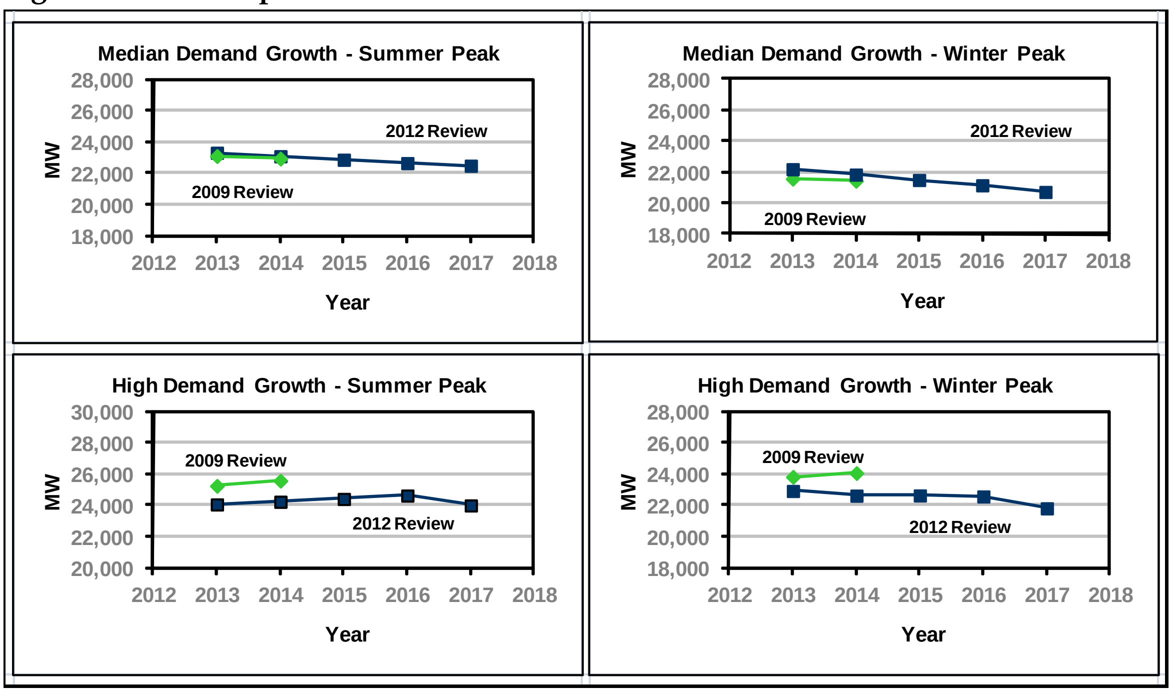
Year	Normal Weather Summer Peak					
	Median Demand Growth			High Demand Growth		
	2009 Review	2012 Review	Difference	2009 Review	2012 Review	Difference
2013	23,092	23,301	209	25,234	24,046	-1,188
2014	22,932	23,079	147	25,563	24,217	-1,346
2015		22,859			24,395	
2016		22,640			24,614	
2017		22,471			23,980	
Average Growth Rate	-0.69%	-0.90%	-0.21%	1.30%	-0.07%	-1.37%

[1] Price effects include Time of Use Rates, Wholesale Market Prices and the Global Adjustment.

Table 3.2 Comparison of Demand Forecasts: Normal Weather Winter Peak (MW)

Year	Normal Weather Winter Peak					
	Median Demand Growth			High Demand Growth		
	2009 Review	2012 Review	Difference	2009 Review	2012 Review	Difference
2013	21,575	22,192	617	23,809	22,907	-902
2014	21,442	21,845	403	24,051	22,610	-1,441
2015		21,498			22,621	
2016		21,154			22,555	
2017		20,719			21,799	
Average Growth Rate	-0.62%	-1.70%	-1.09%	1.02%	-1.23%	-2.25%

Figure 3.1 Comparison of Demand Forecasts



3.2.2 Resources Forecast

Table 3.3 shows the resources forecast to be available to the Ontario system at the time of the seasonal peaks assumed for this 2012 Comprehensive Review and for the 2009 Comprehensive Review.

Table 3.3 Comparison of Available Resource Forecasts (MW)

Year	Winter Peak			Summer Peak		
	2009 Review	2012 Review	Difference	2009 Review	2012 Review	Difference
2013	33,280	33,728	448	32,316	31,940	-376
2014	31,806	32,038	232	32,739	30,688	-2,051
2015		32,004			30,385	
2016		32,559			29,858	
2017		29,926			28,087	

This 2012 Comprehensive Review assumes resource availability based on the latest available information regarding existing and future resources. For the purpose of this study 13.4% and 33.6% of the installed capacity for wind were assumed to be available at the time of the summer and winter peak respectively. The summer and winter capacity contribution values for solar were modeled as 40% and 0% respectively for this study. The assumptions regarding shutdown of the remaining coal units have been advanced compared to the 2009 Comprehensive Review. In the Northwest zone, the conversion of a unit at Atikokan to burn biomass is underway. Conversion of some or all of the six southern Ontario coal units is being evaluated against other supply alternatives. One gas project was relocated to the west zone and another to the east zone from Toronto. These projects were originally assumed to come in service in 2012 and 2013 respectively.

3.2.3 Resource Adequacy Assessment Criterion

For both the 2009 and the current review, the assessment criterion described in Section 4.1 was used, which is the same as the NPCC resource adequacy criterion.

- End of Section –

4 RESOURCE ADEQUACY CRITERION

4.1 Statement of Resource Adequacy Criterion

The IESO uses the NPCC resource adequacy criterion from Directory #1 to assess the adequacy of resources in the Ontario control area:

> "The probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than one day in ten years as determined by studies conducted for each Resource Planning and Planning Coordinator Area. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas', transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

4.2 Statement of How the Criterion is Applied

The reliability standard is used to assess the adequacy of available resources needed to supply the Ontario Area on an on-going basis, to identify periods of resource deficiency or surplus.

Consideration can be given to Ontario's interconnections with Manitoba, Minnesota, Québec, New York and Michigan and the resultant tie-benefits which can be assumed. However, for this study, interconnection assistance was not required. Scheduled and forced outages to Ontario generators are assessed considering submissions by generator owners, actual historic outage observations and more generalized outage factors.

If necessary, emergency operating procedures will be taken by the IESO to deal with a potential shortfall in reserve in the operating time frame, as summarized below. Load relief from these EOPs is assumed to be available during the five-year period, if required to meet the Loss of Load Expectation criterion. It should also be noted that while the list below provides the anticipated order of the control actions, the IESO may initiate control actions at any point in the hierarchy list, and may alter the order in which the control actions are implemented, depending on the specific circumstances. These actions include the following:

- reject outage applications, revoke approved outages, recall outages;
- issue general or public appeal;
- constrain dispatch of resources;
- purchase emergency energy and request emergency assistance;

- disregard 30-minute operating reserve (OR) requirement;
- disregard high-risk limits;
- disregard 10-minute OR requirement;
- implement 3% voltage reduction;
- implement 5% voltage reduction;
- implement environmental variances;
- operate to emergency condition limits;

Most of these actions are modeled in the MARS program by evaluating the daily LOLE at various margin states. Table 4.1 summarizes the assumptions regarding the load relief from EOPs used when required in this study. Several of the categories above have been aggregated for modeling purposes.

Table 4.1 Emergency Operating Procedure Assumptions

EOP Action	Load Relief (% of Demand or MW Value)
Public Appeals	1.0%
No 30m OR (MW)	473
No 10m OR (MW)	945
Generation Surplus (MW)	228
Voltage Reductions	2.1%

4.3 Resource Requirements to Meet Criterion

For the purposes of this study, the adequacy of Ontario's existing and planned resources is assessed through calculation of the annual LOLE and compared with the 0.1 days/year prescribed by the NPCC resource adequacy criterion. Initial studies were performed with all existing units and projects under contract, as well as units procured by the OPA as directed by the Ministry of Energy, modeled. For all calendar years, additional resources by means of interconnection assistance were not required to meet criterion.

4.4 Comparison of IESO and NPCC Criteria

The IESO reliability criterion for this review is the same as the NPCC criterion.

4.5 Resource Adequacy Studies Done Since the 2009 Review

Adequacy assessments produced by the IESO since the last Area review include 18-Month Outlooks published on a quarterly basis, Ontario Reliability Outlook (ORO) published in 2009, and the annual release of the Ontario Reserve Margin Requirement reports. All of these reports are available on the IESO web site. The 18-Month Outlooks and the ORO were submitted to the Minister of Energy and filed with the Ontario Energy Board (OEB) to meet the requirements of the Ontario Market Rules and the conditions of the IESO's licence.

- End of Section -

5 RESOURCE ADEQUACY ASSESSMENT

5.1 Median Demand Forecast

On average over the forecast period, Ontario electrical energy demand is expected to decrease by about 2.3% annually under the median demand forecast. Over the same period peaks demands are expected to show declines of 0.9% annually. Overall energy demand is expected to decline more than peak demands due to the mix in embedded generation and the underlying economic and population growth. Growth in the commercial and residential sectors will have a greater impact on peak demand hours than overall energy demand while embedded generation's availability means that it will have a greater moderating impact on energy demand than peak demand.

5.1.1 LOLE Values, Median Demand Forecast

Table 5.1 shows that under the median demand growth assumption, Ontario will have adequate resources to meet the NPCC criterion through 2017. Only the first set of MARS runs was required to achieve the LOLE criterion of no more than 0.1 days/year. This was achieved without reliance on any EOPs, without any interconnection assistance. The LOLE in 2015, compared to other years, is higher due to a greater number of generator outages associated with regulatory requirements. It is expected that outage impacts will be minimized prior to 2015 as actual plans are firmed up.

5.2 High Demand Forecast

On average over the forecast period, Ontario electrical energy demand is expected to decrease by about 1.6% annually under the high demand forecast. Peak demands are expected to remain fairly flat in the high growth scenario with average annual growth rates of -0.1%. The same factors are at play as under the medium growth scenario, however in the high demand scenario economic expansion and population growth have a greater positive effect on both peak and energy demand.

5.2.1 LOLE Values, High Demand Forecast

Table 5.1 shows that under the high demand growth assumption, Ontario would meet the LOLE criterion for all years of the study period. Two sets of MARS runs were required to achieve the LOLE criterion of 0.1 days/year. This was achieved without implementing any EOPs for all years but 2015. For the calendar year 2015, the LOLE criterion was achieved after utilizing the EOPs. For all calendar years, interconnection assistance was not required to meet the LOLE criterion.

Table 5.1 Annual LOLE Values, Median and High Demand Forecast

Scenario	EOPs	Additional Resources (MW)	LOLE [days/year]				
			2013	2014	2015	2016	2017
Median	No	0	0.002	0.006	0.041	0.001	0.001
High	No	0	0.008	0.039	0.247	0.042	0.038
High	Yes	0	-	-	0.074	-	-

5.3 Contingency Mechanisms for Managing Demand and Resource Uncertainties

There are several study assumptions which may change in such a way that reserve levels in Ontario could be higher or lower than presented in this Comprehensive Review, including the amount of new generating resources available, the amount of conservation or demand response, the amount of imports and the amount of generation that may be on planned outage.

After the publication of the 2009 Comprehensive Review, the Government of Ontario released its Long-Term Energy Plan (LTEP) in 2010, specifying the target for large scale development of renewable energy projects and implementation of conservation. The renewable resources target for wind, solar and bioenergy is 10,700 MW by 2018. The total hydroelectric generation is targeted at 9,000 MW. Ontario will achieve these targets through the continuation of the Feed-in Tariff (FIT) and microFIT programs. In considering future availability of resources, the IESO includes projects that are under construction, contracted by the OPA or that are planned to be in-service. For projects that are under contract or planned to be in-service, the estimated effective date provided by the OPA is the best estimate of the date when the additional capacity is expected to be available.

Demand response (DR) programs were initiated by the Ontario Government and continue to be developed and managed by the OPA. DR includes a number of different programs which are playing an active role in maintaining the reliability of the system. Some wholesale consumers bid their load into the market and are responsive to price through IESO dispatch instructions. Other consumers have been contracted by the OPA to provide DR under tight supply conditions.

The 18-Month Outlooks published on a quarterly basis forecast weekly reserve levels. Generators and Transmitters use this information to plan their outages. Periods where planned outages result in inadequate resource levels are identified to the concerned generators. The total generator planned outages could range from 0 MW to over 5,000 MW depending on the time of the year. If market participants fail to proactively reschedule planned outages to mitigate concerns, the IESO may reject, revoke or recall outages in the near-term to ensure sufficient capacity is available to meet non-dispatchable demand. The relief that could be expected from this measure during peak seasons ranges from 0 to 2,500 MW. Deviations from initial generator outage plans through outage rescheduling and rejection are not always desirable. This could stretch the ability of generator owners or operators to accommodate larger number and magnitude of outages over shorter time periods and may increase forced outage occurrences. Operational experience so far indicates generator owners are usually able to adapt their outage plans.

The need to consider imports into Ontario to achieve the resource adequacy criterion varies depending on the calendar year under consideration and the demand assumptions. The coincident interconnection import capability is about 5,200 MW. Data collected since market opening reveals the average imports that have been attracted into Ontario with market mechanisms, and NPCC studies have been conducted to indicate an estimate of the annual tie benefits that can be expected. Both the historic import data and the estimate from the NPCC tie benefit studies are indicated later in this report (Appendix A, Section 1.3). For this review, additional resources by means of imports were not required to meet criterion in any of the calendar years.

5.4 Impacts of Major Proposed Changes to Market Rules on Area Reliability

There are currently no major proposed changes to the market rules which are expected to have significant impacts on reliability.

- End of Section -

6 PROPOSED RESOURCE MIX

6.1 Reliability Impacts of Capacity Mix, Demand Resource Response, and Transportation or Environmental Considerations

The Ontario system has a well balanced resource mix with a variety of fuel types, which helps offset the risks possibly associated with an exaggerated dependency on one principal fuel. However, possibilities exist which could drive a shift in the fuel mix and result in certain risks being realized.

Concerns about the emission of greenhouse gases and other pollutants from coal-fired electricity production have led to the provincial decision to phase-out all coal-fired units in Ontario by the end of 2014. This is in accordance with Ontario Regulation 496/07 under the Environmental Protection Act. The OEB made changes to the IESO's license, giving the IESO the authority to manage the recent policy initiatives to curb coal-fired emissions. This authority combined with existing IESO processes will maintain grid reliability while facilitating an orderly reduction in emissions.

Much of the replacement energy is expected to come from gas-fired generation. As Ontario's electricity sector becomes more dependent on natural gas as a primary fuel, the adequacy and security of natural gas supply infrastructure becomes even more critical to the reliability of the electricity system. Overall gas supply adequacy and gas transmission issues have been examined extensively since 2005 by the Ontario Gas Electric Interface Working Group. Canadian and Ontario pipeline and gas-distribution operators have implemented various tariff changes to enhance gas usage flexibility and improve firmness of supply available to generators.

Gas pipeline capacity, historically, has not limited the summer energy or capacity capability of Ontario generation fuelled solely by natural gas and is not expected to be a problem for future summers. Winter months are more prone to gas limitations as heating and gas generation may peak simultaneously. The Working Group has procedures in place for the continued monitoring of operations and identification and resolution of issues to mitigate fuel vulnerability.

There is also expected to be a significant increase in the amount of renewable generation in Ontario, in particular of wind power generation. The IESO has implemented a new Centralized Forecasting Service that is more accurately predicting the output from wind facilities in Ontario. This service will soon be expanded to predict solar output as well. The IESO is also continuing its efforts to incorporate these renewable resources into the dispatch process.

The introduction of the OPA's Demand Response programs specifically target load reduction during hours of tight supply availability or peak periods by signalling to consumers when those demand reductions are most needed. Otherwise, load is shifted from on-peak to off-peak periods under OPA contract. The OPA DR Programs (DR1, DR2 and DR3), Peaksaver and local demand response contracts will provide relief from demand during periods of low supply.

Tables 6.1 and 6.2, and Figure 6.1 show the expected installed capacity mix at the time of the summer peak for each year in the study period. These values do not include generators that operate within local distribution service areas, except for those that participate in the IESO-administered market. This is based on information regarding existing and future resources as of June 2012.

Table 6.1 Ontario Installed Capacity Mix by Fuel Type (MW)

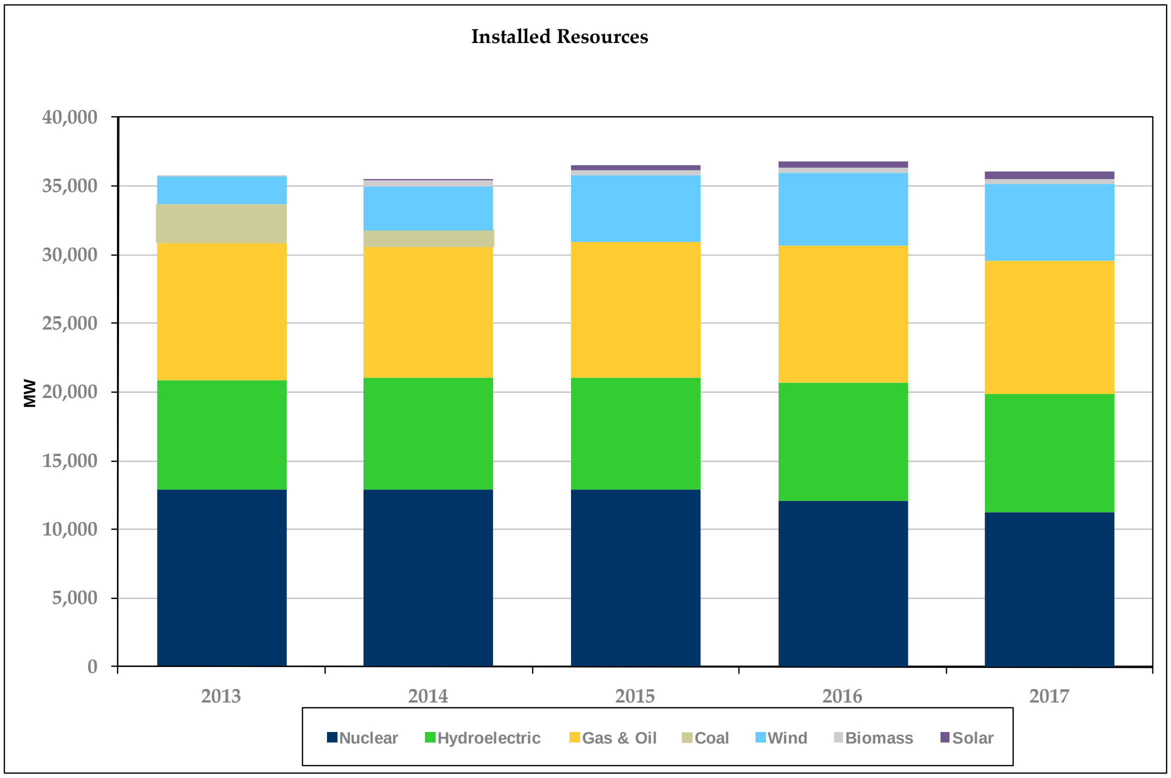
Fuel Type	2013	2014	2015	2016	2017
Nuclear	12,946	12,946	12,946	12,124	11,302
Gas / Oil*	9,989	9,605	9,908	9,932	9,713
Coal	2,792	1,158	0	0	0
Hydroelectric	7,947	8,062	8,110	8,574	8,574
Wind	1,980	3,212	4,837	5,337	5,568
Biomass	162	395	383	383	383
Solar	0	123	360	460	560
Total	35,816	35,501	36,544	36,810	36,100

Table 6.2 Ontario Installed Capacity Mix by Fuel Type (%)

Fuel Type \ Year	2013	2014	2015	2016	2017
Nuclear	36.1	36.5	35.4	32.9	31.3
Gas / Oil*	27.9	27.1	27.1	27.0	26.9
Coal	7.8	3.3	0.0	0.0	0.0
Hydro	22.2	22.7	22.2	23.3	23.8
Wind	5.5	9.0	13.2	14.5	15.4
Biomass	0.5	1.1	1.0	1.0	1.1
Solar	0.0	0.3	1.0	1.2	1.6

* The Gas / Oil category includes 2,100 MW of dual-fuel capability at Lennox Generating Station.

Figure 6.1 Ontario Capacity Mix by Fuel Type



6.2 Available Mechanisms to Mitigate Reliability Impacts of Capacity Mix, Demand Resource Response, Transportation and/or Environmental Considerations

Any increase in the capacity-mix diversity would have beneficial effects on supply flexibility and environmental restrictions. Over the next five years, more than 5,000 MW of new grid-connected wind-powered generation is expected to be in-service in Ontario. Although the wind generation capacity contribution must be substantially discounted from the nameplate value, wind energy can successfully reduce the utilization of greenhouse gas emitting resources. Solar generation too contributes in reducing the greenhouse gas emissions. About 560 MW of solar resources are expected to be connected to the grid in the same period.

The IESO actively encourages diversity in supply options by identifying future capacity needs and engaging in dialogue with the Ontario Government, OPA, market participants and other stakeholders. As a competitive alternative to new and existing generation, the IESO promotes a balanced pursuit of supply diversity and demand management options in its Outlooks.

Assumptions around coal availability and retirements are based on plans developed by OPA in line with the LTEP.

The IESO will continue to monitor the plans for Ontario's future fuel mix and consider the reliability impacts in the Ontario Reserve Margin Requirements, ORO and the 18-Month Outlooks conducted several times each year.

6.3 Reliability Impacts Related to Compliance with Provincial Requirements

In keeping with the policies of the Government of Ontario, the Ontario Regulation 496/07 under the Environmental Protection Act declared the phase-out of generation from coal in Ontario by December 31, 2014. The greenhouse gas emissions target from coal generation implemented by the Ontario government is a "hard" cap of 11.5 million metric tonnes per year.

In May 2009, the Ontario Legislature passed the Green Energy and Green Economy Act (GEA). It is aimed at facilitating large-scale development of renewable energy projects across Ontario. The Act included the Feed-in Tariff Program which is designed to further encourage procurement of renewable energy supply with greater geographic distribution.

- End of Section -

APPENDIX

APPENDIX A - DESCRIPTION OF RESOURCE RELIABILITY MODEL

For the purposes of this study, the IESO used the Multi-Area Reliability Simulation (MARS) program. The MARS program is capable of performing the reliability assessment of a generation system composed of a number of interconnected areas and/or zones that can be grouped into pools.

A sequential Monte Carlo simulation forms the basis for MARS. In this simulation, a chronological system evolution is developed by combining randomly generated operating states for the generating units with inter-zone transfer limits and hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules that govern system operation. Various measures of reliability can be reported using MARS, including the Loss of Load Expectation for various time frames. The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for various reliability indices. These values can be calculated both with and without load forecast uncertainty. The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates LOLE values and can estimate the expected number of times various emergency operating procedures will be implemented in each zone and pool.

The first step in calculating the reliability indices is to compute the zone margins on an isolated basis for each hour, by subtracting the load for the hour from the total available capacity in the hour. If a zone has a positive or zero margin, it has sufficient capacity to meet its load. If the zone margin is negative, the load exceeds the capacity available to serve it, and the zone is in a potential loss-of-load situation. If there are any zones that have negative margins after the isolated zone margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from zones that have positive margins. There are two ways for determining how the reserves from zones with excess capacity are allocated among the zones that are deficient. In the first approach, the user specifies the priority order in which deficient zones receive assistance from zones with excess resources. The second method shares the available excess resources among deficient zones in proportion to the size of their shortfalls. Priorities within pools, as well as among pools, can also be modeled.

1.1 LOAD MODEL

1.1.1 Description and Basis of Period Load Shapes

The IESO uses a multivariate econometric model to produce the electricity demand forecast. The forecast is composed of hourly demand for Ontario and its ten zones. The model uses three broad sets of forecast drivers: calendar variables, weather effects and economic and demographic variables. Conservation and embedded generation are treated outside the model. The impacts of demand response programs are removed from the historical data and those programs are treated as resources in the forecast.

Weather is represented by a Monthly Normal weather scenario which uses last 31 years of historical weather data to generate typical monthly weather. A measure of uncertainty in demand due to weather variability is used in conjunction with the Normal weather scenario to generate a distribution of possible demand outcomes.

The economic drivers are generated using a consensus of publicly available provincial forecasts, along with economic forecasts from service providers. Demographic projections are publicly available from the Ontario Ministry of Finance.

1.1.2 Load Forecast Uncertainty

Load Forecast Uncertainty is a measure used to capture the uncertainty in demand due to variation in the weather elements. LFU represents the impact on demand due to one standard deviation in the weather elements. The LFU varies between roughly 1 and 7 percent of normal demand throughout the year. The MARS program was provided with hourly load data for the entire five-year period, as well as monthly standard deviations (SD), for each of the ten zones modeled. Reliability indices were calculated at each load level around the mean value (mean, mean ± SD, mean ± 2SD, mean ± 3SD), as well as weighted-average indices.

1.1.3 Demand and Energy Projects of Interconnected Entities

The loads and resources of interconnected entities within the Area that are not members of the Area were not considered.

1.1.4 Demand -Side Management

MARS runs were completed which modeled conservation and demand-side management estimates that have been proposed for Ontario. Demand-side management include:

- Dispatchable Loads
- Demand Response (DR) Programs: DR1, DR2 and DR3
- Local Demand Response Contracts
- Direct Load Control (e.g. Peaksaver)

The annual values assumed for conservation at the time of net peak demand and demand-side management are shown in the table below.

Table A.1 Conservation and Demand-side Management Assumptions

Year	Conservation [MW]	Demand Management [MW]
2013	526	1,529
2014	1,029	1,665
2015	1,478	1,668
2016	1,816	1,670
2017	2,136	1,673

1.2 SUPPLY-SIDE RESOURCE REPRESENTATION

MARS has the capability to model the following types of resources:

- Thermal
- Energy-limited
- Cogeneration
- Energy-storage
- Demand management

An energy-limited unit can be modeled probabilistically as a thermal unit with an energy probability distribution or deterministically as a load modifier, or as a unit with a specified capacity and available monthly energy. Co-generation units can be modeled as thermal units with an associated hourly load. Energy-storage and demand management impacts can be modeled as load modifiers. For each unit modeled, the installation and retirement dates and planned maintenance requirements must be specified. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads depend on the unit type. The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis.

All thermal generators in Ontario, for each of the ten zones, were modeled on an individual unit basis. The available capacity states, state transition rates, and planned outage information were input for each thermal unit. Hydroelectric generators were modeled as energy-limited resources. Minimum and maximum ratings and energy production capabilities were input on a monthly basis for the hydroelectric generators. Wind generators were also modeled as energy-limited resources. Wind capacity contributions were input on a monthly basis with a cumulative probability density function.

1.2.1 Ratings

1.2.1.1 Definitions

The aggregated installed capacity values for all generating units expected to be participating in the IESO markets are shown in Table A.2. These values do not include generators that operate within local distribution service areas, except for those that participate in the IESO-administered market.

Table A.2 Installed Capacity

Fuel Type	Total Capacity (MW)	Number of Stations
Nuclear	11,446	5
Hydroelectric	7,947	71
Coal	3,293	3
Gas / Oil*	9,987	29
Wind	1,511	12
Biomass / Landfill Gas	122	6
Total	34,306	126

* The Gas / Oil category includes 2,100 MW of dual-fuel capability at Lennox Generating Station

For resources other than hydroelectric, the monthly output capabilities as submitted by market participants as of July 2012 were input into MARS. These capabilities take into account any stretch capability, output deratings given by equipment or ambient limitations, and environmental restrictions. For future resources, output capabilities based on estimates by the Ontario Power Authority were input into MARS.

Hydraulic station minimum outputs and monthly energy production capabilities submitted by market participants are based on expected river flows. The maximum assumed contribution of hydro resources is based on the median historic contributions at the hour of the weekday peak demand from May 2002 to March 2012.

1.2.1.2 Procedure for Verifying Ratings

The Ontario Market Rules (*Market Rules Chapter 4, Section 5*) require that all generators connected to the IESO-controlled grid test their equipment to ensure compliance with all applicable reliability standards, including NPCC Directory #9 "Verification of Generator Gross and Net Real Power Capability" and Directory #10 "Verification of Generator Gross and Net Reactive Power Capability".

Generators communicate to the IESO any changes to their units' verified gross and net MW capabilities as part of the Outage Management Process and the Facility Registration, Maintenance and De-registration Process. *Market Manual 7.3 "Outage Management"* and *Market Manual 1.2 "Facility Registration, Maintenance and De-registration"*

Permanent changes to equipment that affect the MW output capabilities of generating units are communicated and assessed through the Connection Assessments process. *Market Manual 2.10 "Connection Assessment and Approval Procedure"*

Generators provide to the IESO the declared seasonal net MW values for their units as part of the 18-Month Outlook process, *Market Manual 2.11 "18-Month Outlook and Related Information Requirements"*

Market Rules (*Market Rules Chapter 4, Section 5.2)* also authorise the IESO to test any generation facility connected to the IESO-controlled grid to determine whether such facility complies with the applicable reliability standards.

1.2.2 Unavailability Factors Represented

1.2.2.1 Type of Unavailability Factors Represented

Equivalent Forced Outage Rate (EFOR) for each unit is used that reflects both forced outages and periods of derated output. These were based on five-year history of actual forced outages unless there was insufficient data for a specific unit(s) for which data supplied by market participants was used.

Planned maintenance was modeled on a unit basis. Where available, representative outage plans supplied by market participants were used, as well as forecast Planned Outage Factors (POF) and/or the Generic Outage Plan derived from historic outage patterns of existing units.

1.2.2.2 Source of Unavailability Factors Represented

POF values used in this study are regularly provided by market participants to the IESO for its routine Outlooks. Actual outage history from which some EFORs were derived was obtained from the IESO's Integrated Outage Management System (IOMS). For units with insufficient historic data, where available, EFOR for these units were based on specific data supplied by market participants as of July 2012.

1.2.2.3 Maturity Considerations and In-Service Date Uncertainty

The MARS runs assumed new gas-fired generators to have a 3% to 5% EFOR, depending on the type of gas generator (e.g. simple cycle, combined cycle, combined heat and power). Review of actual forced outage history of gas units revealed that the forced outage rates of new gas units are expected to decline as they mature. At some point in the future, they are expected to stabilize.

There is some uncertainty in the date that new generating resources will come into service. For projects that are under contract or planned to be in-service, the estimated effective date provided by the OPA is the best estimate of the date when the additional capacity is expected to be available.

1.2.2.4 Tabulation of Typical Unavailability Factors

The ranges of EFOR indices, used for this study, are contained in the table below. EFORs for nuclear, coal and gas units were derived from a five-year history of actual forced outages that reflect past experiences. EFORs for biomass and oil units were provided by market participants since the historic information was found to be insufficient.

Table A.3 Ontario Projected Equivalent Forced Outage Rates

Fuel Type	Weighted Average EFOR	Range of EFOR
Biomass	4%	2 - 8%
Coal	15%	6 - 20%
Gas	5%	1 - 6%
Nuclear	8%	3 - 30%
Oil	15%	5 - 50%

1.2.3 Purchase and Sale Representation

At present, there are no firm, expected or provisional purchases or sale contracts identified for the five-year study period. However, for use during daily operation, operating agreements between the IESO and neighbouring jurisdictions in NPCC, RFC and MRO include contractual provisions for emergency imports directly by the IESO. IESO also participates in a shared activation of reserve group which includes PJM, NYISO, ISO-NE and New Brunswick.

1.2.4 Retirements

All coal units are identified to be removed from service by December 31, 2014. A coal shutdown and conversion plan, subject to annual CO2 emission targets set by the government, is used for the study.

1.3 REPRESENTATION OF INTERCONNECTED SYSTEMS

There are five systems with which the Ontario system is interconnected: Manitoba, Minnesota, Michigan, New York and Québec. The five interconnected systems that can provide assistance to the Ontario system are modeled as external to the Ontario pool. Neighbouring systems are treated as external areas with constant hourly loads of 1 MW. In each of these external areas a dummy generator can be modeled, with a variable capacity up to the amounts expected to be offered into the Ontario market. The expected capacity values vary, depending on Ontario needs, but are always subject to the limitations of the transmission interconnections outlined in Table A.4. Limits apply year-round except where seasonal ratings are indicated.

However, for this review, the five interconnected systems were not modeled in MARS since additional assistance was not required to meet the resource adequacy criterion.

Table A.4 Ontario Interconnection Limits

Interconnection	Limit - Flows Out of Ontario MW	Limit - Flows Into Ontario MW
Manitoba – Summer*	**288** (3)	**288** (3,6)
Manitoba – Winter*	**300** (3)	**300** (3,6)
Minnesota	**150** (3)	**100** (3)
Quebec North (Northeast) – Summer*	**95** (5)	**65**
D4Z	0	65
H4Z	95	0
Quebec North (Northeast)– Winter*	**110** (4)	**85**
D4Z	0	85
H4Z	110	0
Quebec South (Ottawa) – Summer*	**1,482**	**1,923**
X2Y	0	65
Q4C	32	88
P33C	0	270
D5A	200	250
H9A	60	120
HVDC (A41T+A42T)	1,250	1,250
Quebec South (Ottawa) – Winter*	**1,502**	**1,998**
X2Y	0	65
Q4C	52	88
P33C	0	345
D5A	200	250
H9A	60	176
HVDC (A41T+A42T)	1,250	1,250
Quebec South (East) – Summer*	**420**	**800**
B31L + B5D	420	800
Quebec South (East) – Winter*	**470**	**800**
B31L + B5D	470	800
New York St. Lawrence – Summer and Winter*	**300**	**300**
New York Niagara – Summer*	**1,760** (1)	**1,320** (1,7)
Emergency Transfer Limit - Summer*	**2,160** (1)	**1,860** (1,7)
New York Niagara – Winter*	**2,080** (1)	**1,570** (1,7)
Emergency Transfer Limit - Winter*	**2,200** (1)	**2,200** (1,7)
Michigan – Summer*	**1,900** (2,3)	**1,600** (2,3)
Emergency Transfer Limit - Summer*	**2,520** (2,3)	**1,950** (2,3)
Michigan – Winter*	**2,000** (2,3)	**1,600** (2,3)
Emergency Transfer Limit - Winter*	**2,450** (2,3)	**2,000** (2,3)

* Summer Limits apply from May 1 to October 31. Winter Limits apply from November 1 to April 30.
(1) Flow limits depend on generation dispatch outside Ontario.
(2) Normal limits are based on LT ratings and phase shifters regulating; Emergency limits are based on ST ratings and phase shifters regulating. Flow limits vary depending on the generation dispatch within Ontario.
(3) For real time operation of the interconnection, limits are based on ambient conditions.
(4) Limit based on 0-4 km/hr wind speed and 10 Deg.C ambient temperature.
(5) Limit based on 0-4 km/hr wind speed and 30 Deg.C ambient temperature.
(6) Flows into Ontario do not include flows on circuit SK1.
(7) Flow Limits into Ontario are shown here without considering QFW transmission constraints within Ontario.

The 2011 NPCC CP-8 study entitled "Review of Interconnection Assistance Reliability Benefits" published in June 2011 provided an assessment that about 4,990 MW of interconnection assistance is reasonably available to the Ontario system by 2015.

1.4 MODELING OF VARIABLE AND LIMITED ENERGY RESOURCES

Hydroelectric generators were modeled as energy-limited resources. Minimum and maximum ratings and monthly energy production capabilities were input on a monthly basis for the hydroelectric generators. The MARS program was directed to dispatch the energy-limited resources on an as-needed basis, subject to the minimum and maximum capacity, and energy production capability limitations.

Wind generation was modeled probabilistically as a Type 1 Energy-Limited Resource with a cumulative probability density function (CPDF). The CPDF was derived by taking the median wind capacity factor from historical wind output at selected peak hours. Both modeled (10 years of history) and actual (6 years of history) wind output data was used. A conservative approach of taking the lower of the two (modeled or actual) capacity values was applied. Seasonal CPDF for summer and winter months, and monthly CPDF for shoulder months were modeled in MARS to represent various wind contribution to the system. Thirteen percent of the installed wind capacity was assumed to be available at the time of summer peak, and thirty three percent was assumed to be available at the time of winter peak.

1.5 MODELING OF DEMAND SIDE RESOURCES AND DEMAND RESPONSE PROGRAMS

For the resource assessments, MARS runs were modeled with dependable demand response capacity. The OPA is actively working towards reducing electricity consumption and demand through their demand response (DR) programs. In the long term, depending on the program, DR reduces demand or shifts load from on-peak to off-peak periods, which reduces the need for additional capacity.

OPA's DR1 program is a voluntary program that allows participants to receive compensation for curtailing the electricity demand of their Project. Unlike the DR1 program, the DR2 program is a non-voluntary, contractual load shifting program. Each participant must comply with their DR2 contract schedule to load shift a pre-determined amount. The DR3 program is also non-voluntary, and participants will be required to curtail their respective Projects in response to notices issued by the OPA. It is not certain how often consumers would tolerate calls for demand response, and Ontario should plan to acquire other resources rather than rely on demand response for sustained periods.

MARS runs were completed with conservation quantities up to 2,136 MW and demand-side management quantities up to 1,673 MW by 2017. The table of conservation and demand-side management assumptions are shown in Table A.1.

1.6 MODELING OF ALL RESOURCES

All generators registered in the IESO-administered market were modeled in the study according to their type, as described in Section 1.2 and 1.4.

1.7 OTHER ASSUMPTIONS

1.7.1 Internal Transmission Limitations

The Ontario IESO-controlled grid consists of a robust southern grid and a sparse northern grid. It has been modeled as a pool composed of ten zones. Figure A.1 provides a pictorial representation of Ontario's ten zones. All transmission interfaces between the ten zones within the Ontario pool were modeled as they are defined in IESO System Control Orders (SCO). No random transmission outages were modeled on the interfaces. The transfer limits were specified for each direction of the interface (positive and negative) and were changed seasonally, if necessary. The amount of assistance that deficient zones were permitted to receive from zones with excess resources was limited by the transfer limits on the interfaces, as shown in Table A.5. Limits apply year-round except where seasonal ratings are indicated. The transfer limits in the table are based on normal continuous ratings, not emergency ratings.

Scheduled return-to-service of Bruce units 1 and 2 in 2012 combined with the contracted new wind power resources in southwestern Ontario will increase generation capacity in the Bruce and Southwest zones.

The newly built double-circuit 500 kV line from Bruce to Milton will accommodate the future increases to generation capacity in the Bruce area and reliably deliver the full benefits of the Bruce refurbishment project and the development of new renewable resources in southwestern Ontario. Flow Away from Bruce Complex plus Wind (FABCW) limit of 8,560 MW is used from January 2013. The FABCW limit is expected to increase to 8,860 MW with the installation of an SVC at Milton TS in July 2015.

Figure A.1 Ontario's Zones, Interfaces, and Interconnections

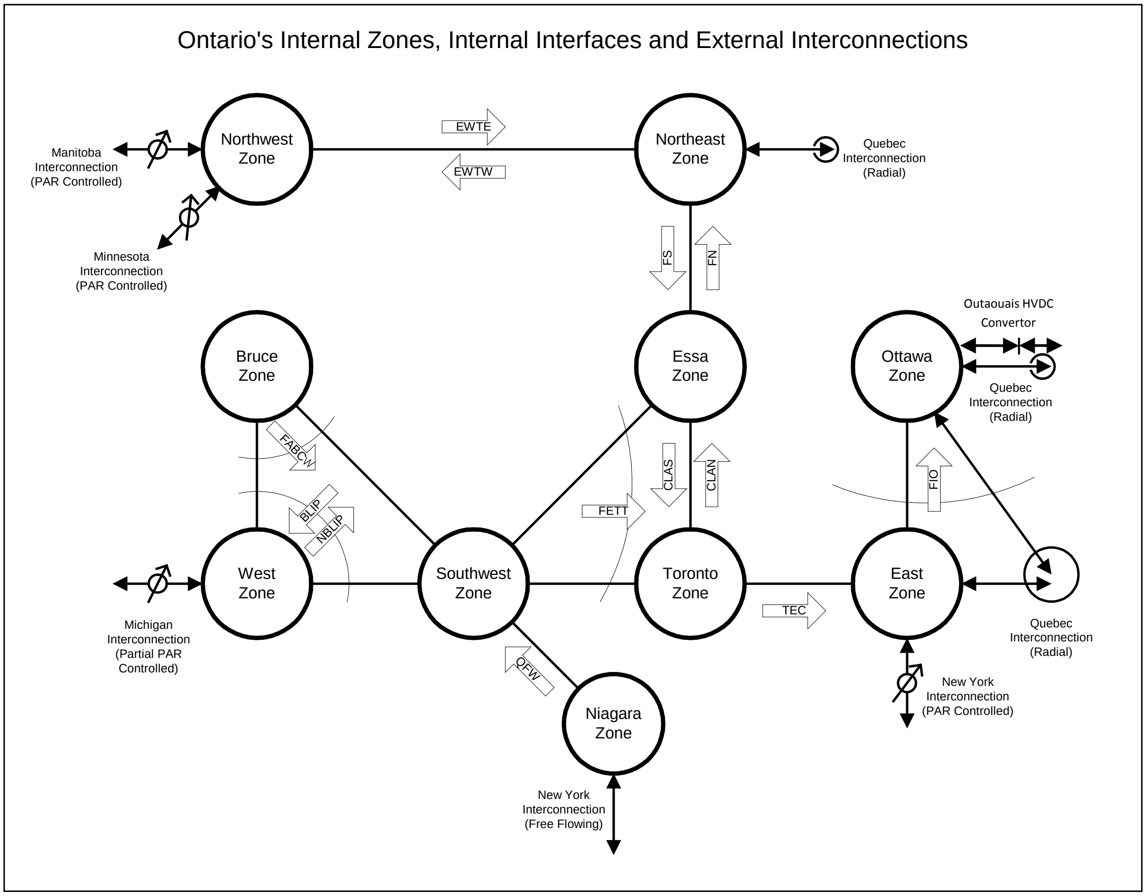


Table A.5 Ontario Internal Interface Base Limits at present

Interface	Operating Security Limits (MW)
BLIP	3,000
NBLIP	1,500
QFW	1,780 Summer, 2,080 Winter
FABCW	6550
FETT	4500 *
CLAN	2000
CLAS	1000
FIO	2900
FN	1,900
FS	1,550
EWTE	325
EWTW	350

Summer Limits apply from May 1 to October 31. Winter Limits apply from November 1 to April 30.

(*) FETT limit is a fixed boundary condition limit

1.8 RELIABILITY IMPACTS OF MARKET RULES

There are currently no major proposed changes to the market rules which are expected to have significant impacts on reliability.

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