NPCC 2015 Ontario Comprehensive Review Of Resource Adequacy

FOR THE PERIOD FROM 2016 TO 2020 | DECEMBER 2015

Independent Electricity System Operator

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Document Change History

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1.0	For submission to CP-8	October 7, 2015
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1 EXECUTIVE SUMMARY

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). The 2015 Comprehensive Review of Resource Adequacy covers the study period from 2016 through 2020 and supersedes previous reviews.

Since the last Comprehensive Review conducted in 2012, 4,074 megawatts(MW) of new generation capacity has been added in Ontario, while 3,300 MW of coal-fired generation has been retired. Capacity additions include 1,544 MW of wind, 140 MW of solar, 501 MW of hydroelectric, 358 MW of biofuel and 1,531MW of nuclear generation.

Another 4,100 MW of generating resource capacity is either under construction or planned to come into service, while 481 MW of capacity is expected to retire over the horizon of this study.

The IESO determines Ontario's level of resource adequacy using the General Electric Multi-Area Reliability Simulation (GE-MARS) program and applies the NPCC criterion that requires a loss of load expectation (LOLE) value of no more than 0.1 days/year for study years.

The results presented in Table 1.1 show that the NPCC LOLE criterion is satisfied for both median and high demand forecast scenario.

For the median demand growth scenario, the NPCC criterion is satisfied for 2017, 2019 and 2020 with existing and planned resources. For 2016 and 2018 forecast years, limited use of Emergency Operating Procedures (EOPs) is needed to satisfy the NPCC criterion.

For the high demand growth scenario, the NPCC criterion is satisfied for 2016 and 2017 with existing and planned resources and limited use of EOPs. For 2018, 2019 and 2020 forecast years, up to 1,350 MW of tie benefits in addition to EOPs are required to meet the LOLE criterion. However, if planned outages are rescheduled, then only 300 MW of tie benefits are required for the year 2019.

Table 1.1 Annual LOLE Values, Median and High Demand Forecast

Scenario	EOPs	Outages Rescheduled	Tie Benefits (MW)	LOLE [days/year]				
				2016	2017	2018	2019	2020
Median	No	No	0	0.124	0.059	0.183	0.057	0.004
	Yes	No	0	0.032	-	0.051	-	-
High	No	No	0	0.178	0.231	1.207	0.773	0.298
	Yes	No	0	0.048	0.065	0.483	0.274	0.108
	Yes	No	1,350	-	-	0.100	0.049	0.017
	Yes	Yes	300	-	-	0.057	0.099	0.066

Major assumptions used in the assessment are summarized in Table 1.2.

Table 1.2 Major Assumptions

Assumptions	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 monthly forecast uncertainty factors
Energy Demand Growth Rate	Median Demand Growth: -1.2% per annum (average) High Demand Growth: +1.0 % per annum (average)
Generating Capacity Additions	4,100 MW by the end of 2020
Generating Capacity Retirements	481 MW of capacity by the end of 2020
Internal Transmission Constraints	10-zone transmission model with IESO's normal system operating security limits applied on interfaces between zones
Tie Benefits	Tie benefits used as needed
Firm Contracts	500 MW to Quebec in winter months of 2015/2016 and 2016/2017.
Emergency Operating Procedures	Public appeal, operating reserve, voltage reduction and generator stretch capability. Aggregated net impact of EOPs: 3% of demand + 151 MW
Unit Availability	Planned outages are based on outage submissions from market participants. Nuclear refurbishment outages are based on the 2013 Ontario's Long Term Energy Plan (LTEP). Sensitivity studies were performed for keeping planned outages 'as is' vs. moving them for when reliance on tie-benefits was needed. Nuclear refurbishment outages were not moved in the sensitivity studies. Equivalent Forced Outage Rates (EFOR) are derived from a rolling five-year history of actual forced outages and forced derates. Units with insufficient historical data are based on either forecast EFOR from market participants or similar units.
Conservation and Embedded Generation	Used as load modifiers and reflected in the demand forecast. Conservation: Up to 1,363 MW by 2020 Embedded Generation: Up to 4,579 MW by 2020
Demand Management	Used as a resource. Up to 676 MW of effective summer capacity at peak by 2020

- End of Section –

2 TABLE OF CONTENTS

2.1 List of Tables

2.2 List of Figures

3 INTRODUCTION

The 2015 Comprehensive Review of Resource Adequacy for Ontario is submitted to the Northeast Power Coordinating Council (NPCC) in accordance with Appendix D of the NPCC Regional Reliability Reference Directory #1, *"Design and Operation of the Bulk Power System."*

This report was prepared by the Independent Electricity System Operator (IESO) in its role as the Planning Coordinator for Ontario.

The 2015 Comprehensive Review of Resource Adequacy covers the study period from 2016 through 2020 and supersedes previous reviews. The previous Comprehensive Review was approved by the NPCC Reliability Coordinating Committee in November 2012 and covered the 2013 to 2017 period.

3.1 Comparison of 2015 vs. 2012 Comprehensive Review

3.1.1 Demand Forecast

Tables 3.1 and 3.2 show a comparison between the peak demand forecasts for the 2012 Comprehensive Review and the 2015 Comprehensive Review under median and high demand growth scenarios for the overlapping years. These tables also present peak demand forecasts for the years 2018 to 2020.

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

Year	Normal Weather Summer Peak					
	Median Demand Growth			High Demand Growth		
	2012 Review	2015 Review	Difference	2012 Review	2015 Review	Difference
2016	22,640	22,849	209	24,614	23,077	-1,537
2017	22,471	22,819	348	23,980	23,732	-248
2018		22,790			24,431	
2019		22,669			24,936	
2020		22,522			24,886	
Average Growth Rate	-0.75%	-0.36%		-2.58%	1.90%	

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

Year	Normal Weather Winter Peak					
	Median Demand Growth			High Demand Growth		
	2012 Review	2015 Review	Difference	2012 Review	2015 Review	Difference
2016	21,154	22,380	1,226	22,555	22,603	48
2017	20,719	21,961	1,242	21,799	22,839	1,040
2018		21,542			23,093	
2019		21,423			23,565	
2020		21,307			23,544	
Average Growth Rate	-2.06%	-1.22%		-3.35%	1.02%	

Over the forecast period, Ontario energy demand is expected to decrease by about 1.2% annually under the median demand forecast, and increase by about 1.0% annually under the high demand forecast.

Ontario demand is broadly shaped by a number of factors: economic growth, population growth, conservation savings, price impacts and embedded generation. Each factors impacts varies based on the season.

Since the 2012 Comprehensive Review, the provincial economy has not grown as strongly as expected. However, the current economic climate is more favourable to Ontario's economy. Low oil and gas prices, a stronger U.S. economy and a low Canadian dollar all help Ontario's export-oriented energy intensive industries.

Over the forecast horizon, both the summer and winter peaks are expected to decline under the median growth scenario. This is due to the fact that the downward pressure from price impacts, increased conservation savings and the growth in embedded generation output outstrips the underlying growth from economic expansion and population growth, leading to declining peaks.

Previously, summer peaks were expected to decline significantly primarily due to the offsets from embedded solar. Although embedded solar significantly impacts the summer peak, its secondary impact is that of pushing the peak later in the day when the output of embedded solar is declining. Therefore, the decline in summer peaks is expected to be lower than previously anticipated for the median demand scenario.

Winter peaks are expected to decline due primarily to improvements in lighting efficiency as LEDs supplant both incandescent and CFL bulbs. The winter peaks are not as negatively impacted by embedded generation, as the majority of the embedded capacity is solar and the winter peak occurs after sundown.

In the High Growth scenario, both the winter and summer peaks are expected to grow over the forecast horizon as the positive economic environment spurs electricity demand. At the same time, the factors offsetting growth – embedded generation, electricity prices and conservation – are not strong enough to offset the underlying growth.

In both the Median and High Growth forecasts, the effect of price-responsive loads reducing on their own under the Industrial Conservation Initiative (ICI) are included and discussed in the next section.

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.

3.1.2 Resource Forecast

Tables 3.3 and 3.4 show installed capacity and available capacity at summer peaks, and Table 3.5 and 3.6 show expected installed capacity and available capacity at winter peak for the study period. These values do not include generators that operate within local distribution service areas (embedded generation), except for those that participate in the IESO-administered market. The resource forecast is based on information available to the IESO as of June 2015.

Table 3.3: Installed Capacity at Summer Peak (MW)

Fuel Type	2016	2017	2018	2019	2020
Nuclear	12,978	12,978	12,978	12,978	12,978
Gas / Oil*	10,073	9,933	9,811	10,530	10,535
Hydroelectric	8,467	8,522	8,556	8,609	8,609
Wind	4,148	4,445	4,700	5,000	5,000
Biofuel	458	458	508	508	520
Solar	274	514	514	654	654
DR	1,305	1,305	1,305	1,305	1,430
Total	37,702	38,154	38,371	39,584	39,726

Table 3.4: Available Capacity at Summer Peak (MW)

Fuel Type	2016	2017	2018	2019	2020
Nuclear+	12,173	11,312	11,311	10,547	11,308
Gas / Oil*	8,925	8,816	8,733	9,327	9,328
Hydroelectric	5,879	5,908	5,921	5,952	5,952
Wind	564	605	639	680	680
Biofuel	424	424	473	473	484
Solar	55	104	104	132	132
DR	576	576	576	576	676
Total	28,596	27,745	27,757	27,687	28,560

Table 3.5: Installed Capacity at Winter Peak (MW)

Fuel Type	2016	2017	2018	2019	2020
Nuclear	12,978	12,978	12,978	12,978	12,978
Gas / Oil*	10,073	10,073	9,811	10,587	10,535
Hydroelectric	8,467	8,501	8,544	8,605	8,609
Wind	3,867	4,445	4,445	5,000	5,000
Biofuel	458	458	508	508	558
Solar	274	514	514	654	654
DR	1,305	1,305	1,305	1,305	1,305
Total	37,422	38,274	38,104	39,637	39,639

Table 3.6: Available Capacity at Winter Peak (MW)

Fuel Type	2016	2017	2018	2019	2020
Nuclear+	12,940	11,312	11,311	10,547	10,541
Gas / Oil*	9,455	9,451	9,236	10,008	9,953
Hydroelectric	6,428	6,454	6,479	6,527	6,530
Wind	1,442	1,658	1,658	1,865	1,865
Biofuel	424	424	473	473	520
Solar	0	0	0	0	0
DR	713	713	713	713	713
Total	31,402	30,012	29,870	30,133	30,122

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

+ Nuclear units on refurbishment are reflected as a reduction in available capacity

Tables 3.4 and 3.6 show available capacity of supply resources at the time of the summer and winter peaks. Resources considered in this review include all existing and planned resources expected to be in service during the review period. Planned resources include all committed projects under contract with the IESO and capacity expected to be contracted in future as directed by the Ontario Ministry of Energy.

Available resources are determined based on the following:

1) Historical median contribution of hydro resources during peak demand hours;

2) Total capacity available from thermal units (nuclear, gas, oil and biofuel) after discounting for seasonal derating;

3) Historical median contribution of wind and solar resources during the peak demand hours; and

4) Effective capacity of projected demand measure resources: peaksaver PLUS, Demand Response (DR)/ Capacity-Based Demand Response (CBDR) and Dispatchable Loads.

Table 3.7 shows how the available capacity of supply resources has changed compared with the 2012 Comprehensive Review. Planned outages are not included in this table; however, the effects of nuclear refurbishments are reflected as reduction in available capacity.

Table 3.7: Comparison of Available Resource Forecasts (MW)

Year	Winter Peak			Summer Peak		
	2012 Review	2015 Review	Difference	2012 Review	2015 Review	Difference
2016	32,559	31,402	-1,157	29,858	28,596	-1,262
2017	29,926	30,012	86	28,087	27,745	-342
2018		29,870			27,757	
2019		30,133			27,687	
2020		30,122			28,560	

The differences in available resources between 2015 Comprehensive Review and 2012 Comprehensive Review are primarily due to:

- Approximately 350 MW of price-responsive demand is now reflected in the demand forecast rather than in the resources side. This is a result of price-responsive loads reducing on their own under the ICI[1].

- Effective capacity for DR resources is reported instead of the gross capacity. This change reduces the available resources by approximately 730 MW when compared to the 2012 Comprehensive Review.

- Removal of the government-directed 245 MW combined heat and power (CHP) resources, which were scheduled to be in-service by January 2015.

- Current projections for 2017 now assume less generation capacity on outage than it was assumed in the 2012 Comprehensive Review.

The remaining differences in resources are from small updates to hydroelectric, wind, solar and biofuel resource contributions. In addition, some attrition in new projects and changes to in-service dates of future wind and solar resources also contributed to the differences.

- End of Section -

[1] ICI applies to customers with a peak demand greater than 3MW. Under the program, these customers are charged Global Adjustment based on their percentage contribution to the top five peak demand hours each year. In 2014, the ICI program expanded to allow eligible customers with a peak demand for electricity above 3 MW to participate, instead of the previous 5 MW threshold.

4 RESOURCE ADEQUACY CRITERION

The IESO uses the NPCC resource adequacy criterion from Directory #1 to assess the adequacy of resources in the Ontario Planning Coordinator 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."

The IESO uses the Load Forecast Uncertainty (LFU) associated with the normal weather demand forecast for this assessment, which captures the variability of the weather scenario. The LFU is modelled through the use of probability distribution.

Scheduled and unscheduled outages to Ontario generators are assessed by considering submissions by generator owners, actual historic outage observations and more generalized outage factors.

Emergency operating procedures (EOPs) are used in the resource adequacy assessment if the existing and planned resources are not sufficient to meet the Loss of Load Expectation (LOLE) criterion. Table 4.1 summarizes the assumptions regarding the load relief from EOPs used when required in this study. For this study, all EOPs are applied in one block.

Table 4.1 Emergency Operating Procedure Assumptions

EOP Measure	EOP Impact	
	% of Demand	MW
Public Appeals	1.0	
No 30-minute OR (473 MW)		0*
Generator Stretch Capability		151
No 10-minute OR (945 MW)		0*
Voltage Reductions	2.0	
Aggregated Net Impact	**3.0% Reduction in Demand + 151 MW**	

* Although 30-minute and 10-minute OR are included in this list of EOPs, the analysis does not impose a requirement to provide for OR since only loss of load events are being considered. Therefore, the net benefit of applying EOPs in the analysis excludes relaxation of OR requirements.

Ontario's interconnections with Manitoba, Minnesota, Quebec, New York and Michigan and the resultant tie-benefits are used as needed, within the constraints of the inter-tie transfer capabilities and the most recent NPCC Tie Benefits Study[2].

To meet the criteria for the period of consideration, in addition to Ontario's existing and planned resources, limited use of EOPs and interconnection assistance of up to 1,350 MW are required in this study for some calendar years and demand scenarios. However, if planned outages are rescheduled, then only 300 MW of tie benefits are needed for the year 2019.

The results of this report showing that Ontario will meet its LOLE criterion over the next five years are consistent with the results of previous studies, which include the 2012 Comprehensive Review, and the 2013 and 2014 Interim Reviews.

- End of Section -

[2] NPCC, Review of Interconnection Assistance Reliability Benefits, June 1, 2011

5 RESOURCE ADEQUACY ASSESSMENT

The resource adequacy probabilistic assessment is performed using GE-MARS. The following inputs were used:

- Median and high demand growth forecast and associated load forecast uncertainty (LFU);
- Forecast of available resources and existing EOPs;
- Planned outage schedules submitted by market participants;
- Equivalent forced outage rates (EFORS) for thermal units derived using historical generator performance data; and
- Transmission limits of major interfaces connecting different zones.

The above inputs are described in greater detail in Appendix A of this report. Sensitivity studies are performed for keeping planned outages 'as is' vs. moving them for situations where reliance on tie-benefits was needed.

5.1 Assessment Results

The results for the median and high demand growth scenarios are presented in Table 5.1 and show that the NPCC LOLE criterion is satisfied for both median and high demand forecast scenarios.

For the median demand growth scenario, the NPCC criterion is satisfied for 2017, 2019 and 2020 with existing and planned resources. For 2016 and 2018 forecast years, limited use of EOPs are needed to satisfy the NPCC criterion.

For the high demand growth scenario, the NPCC criterion is satisfied for 2016 and 2017 with existing and planned resources and limited use of EOPs. For 2018, 2019 and 2020 forecast years, up to 1,350 MW of tie-benefits in addition to EOPs are required to meet the LOLE criterion. However, if planned outages are rescheduled, then only 300 MW of tie benefits are required for the year 2019.

Table 5.1 Annual LOLE Values, Median and High Demand Forecast

Scenario	EOPs	Outages Rescheduled	Tie Benefits (MW)	LOLE [days/year]				
				2016	2017	2018	2019	2020
Median	No	No	0	0.124	0.059	0.183	0.057	0.004
	Yes	No	0	0.032	-	0.051	-	-
High	No	No	0	0.178	0.231	1.207	0.773	0.298
	Yes	No	0	0.048	0.065	0.483	0.274	0.108
	Yes	No	1,350	-	-	0.100	0.049	0.017
	Yes	Yes	300	-	-	0.057	0.099	0.066

5.2 Demand and Resource Uncertainties

As in any system adequacy forecast, there are inherent uncertainties related to demand and resources, which include changes to demand forecast drivers, adjustments to generation resource availability, conservation or demand response, import or tie benefits support. The IESO has various ways to mitigate these uncertainties.

Flexibility, cost, and environmental performance have been incorporated in Ontario`s plan to ensure that commitment decisions are made in a timely manner. If additional resources are needed, market based mechanisms such as the Demand Response Auction are planned to facilitate procuring new resources.

Although not modelled in this assessment, Ontario has the option to call on up to 500 MW of summer capacity from Quebec starting in 2017 as a result of a seasonal firm capacity sharing agreement between Ontario and Quebec. Additional options include re-contracting non-utility generator (NUG) facilities as their contracts reach maturity, new gas-fired generation, imports, energy storage and additional conservation above current targets.

Every quarter, looking out 18 months into the future, the IESO assesses the near term adequacy and reliability of Ontario's system integrating the generator and transmission outage plans of market participants. Periods where outages result in inadequate resource levels are identified to generators and transmitters. If market participants do not reschedule outages to address identified adequacy concerns, the IESO may reject outages.

When required, Ontario can rely upon its neighbours to help it meet the resource adequacy criterion. The coincident interconnection import capability is approximately 5,200 MW. The most recent NPCC Tie Benefits study indicates a range of estimated tie benefit potential of 3,690 MW to 4,990 MW. For this review, additional resources by means of imports are required to meet the criterion in 2018, 2019 and 2020 under high demand growth scenario. However, if outages are rescheduled, then the study shows that only 300 MW of tie benefits are needed for the year 2019.

5.3 Impact of Proposed Changes on Area Reliability

An annual Demand Response Auction is currently being developed by the IESO to procure DR capacity through a cost-competitive mechanism. The quantity of DR capacity that the auction will seek to procure will be equivalent to the quantity expiring from the transitional Capacity-Based Demand Response (CBDR). The combined total of DR capacity in the CBDR program and selected through the DR auction will remain approximately 500 MW, which is consistent with what was previously procured under DR2 and DR3 contracts. The first Demand Response Auction will be held in December 2015 for both a Summer (May 1, 2016 – October 31, 2016) and Winter (November 1, 2016 – April 30, 2017) commitment periods. The effect of the DR action is expected to be positive, as the DR resources clearing the market would have the obligation and the incentives to be available when needed for reliability, and would also allow a higher frequency of deployment than the DR procured under previous programs.

The IESO is working with stakeholders to develop a capacity auction for Ontario. While this work is in the early stages, the IESO has posted a draft high-level market design for stakeholder feedback. As set out in the draft design, the capacity auction would be a new mechanism for meeting resource adequacy requirements in Ontario and would be implemented in time to meet incremental demand as it arises in the future.

5.4 Proposed Resource Capacity Mix and Reliability Impacts

The Ontario resource mix is well-balanced with a variety of fuel types. A diverse generation mix is important for resource adequacy and market efficiency, because it provides dispatch flexibility and reduced vulnerability to fuel supply contingencies.

The expected installed capacity mix at the time of the summer peak for each year of the study period is listed in Tables 3.3 and 6.1. These values do not include generators that operate within local distribution service areas (embedded generation), except for those that participate in the IESO-administered market. This is based on information as of June 2015.

Table 6.1 Ontario Installed Capacity Mix by Fuel Type (%) at Peak Day

Fuel Type \ Year	2016	2017	2018	2019	2020
Nuclear	34.4	34.0	33.8	32.8	32.7
Gas / Oil*	26.7	26.0	25.6	26.6	26.5
Hydro	22.5	22.3	22.3	21.7	21.7
Wind	11.0	11.7	12.2	12.6	12.6
Biofuel	1.2	1.2	1.3	1.3	1.3
Solar	0.7	1.3	1.3	1.7	1.6
DR	3.5	3.4	3.4	3.3	3.6

* The Gas / Oil category includes 2100 MW of dual-fuel capability at Lennox Station.

Resource Availability Considerations

There are several modelling technics employed to mitigate reliability impacts resulting from the proposed resource availability.

For thermal units, Equivalent Forced Outage Rates (EFOR) for existing units is derived using rolling five-year history of actual forced outages. This ensures that nuclear, gas/oil and biofuel units random derates and forced unavailability are represented in the MARS model.

Hydroelectric resources are modeled in MARS as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity and monthly energy values are based on historical production and contribution values.

By the end of 2020, more than 5,000 MW of grid-connected wind-powered generation is expected to be in-service in Ontario. The wind generation capacity contribution is substantially discounted from the nameplate value and represented in the MARS study as a probabilistic model developed on a zonal basis with a cumulative probability density function (CPDF).

There are three main demand management mechanisms in Ontario: peaksaver PLUS, Dispatchable Loads and DR/ Capacity-Based Demand Response (CBDR). In order to reflect reality of demand management programs, the IESO uses effective demand management values instead of gross values. The effective values are based on historical behaviors.

Further details of capacity mix modelling and DR are provided in section 5.3 and Appendix A.3.

Gas Supply Considerations

With the addition of approximately 3,900 MW of gas-fired generation since 2009, the volume of gas consumed for electricity generation in Ontario is increasing. Ontario is well situated with respect to natural gas transmission and storage. Based on the input received from stakeholders, the review of the winter operations conducted by the IESO as part of Ontario's Gas-Electric Coordination Enhancements initiative, and the assessment results of the Eastern Interconnection Planning Collaborative (EIPC) Gas-Electric System Interface Study, the IESO has concluded that Ontario's ability to meet the additional gas supply requirements in the period covered by this review is adequate, and that risk of interruption of gas supply is within acceptable risk tolerance.

Environmental Considerations

Concerns about the emission of greenhouse gases and other pollutants from coal-fired electricity production led to the provincial decision to phase-out all coal-fired units in Ontario. The last coal-fired generation was shut down in 2014, and Ontario is now free from all coal generation.

- End of Section -

APPENDIX A: DESCRIPTION OF RESOURCE RELIABILITY MODEL

A.1 MARS Program

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 modelled 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 are going to 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 is at 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 are adjusted for curtailable contracts, the program attempts to satisfy these 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 modelled. The IESO uses the first approach.

A.2 Load Model

The IESO uses a multivariate econometric model to produce the electricity demand forecast. The forecast is composed of hourly demand for Ontario and its 10 zones. The model uses three broad sets of forecast drivers: calendar variables, weather effects and economic and demographic variables. The forecast also accounts for conservation, price impacts and embedded generation.

Weather is represented by a Monthly Normal weather scenario which uses the last 31 years of historical weather data to generate typical or average monthly weather. This approach results in a monthly peak demand with a 50/50 probability of being exceeded. 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. In the MARS program, demand is modeled as an hourly profile for each day of each year of the study period. An allowance for load forecast uncertainty (LFU) is also modeled.

LFU arises due to variability in the weather conditions that drive future demand levels. LFU is modeled in MARS through the use of probability distributions. These distributions are derived from observed historical variation in weather conditions that are known to affect demand, including temperature, humidity, wind speed and cloud cover. Province-wide LFU distributions are developed for every month of the year and applied to all 10 transmission zones.

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's Ministry of Finance.

Conservation impacts are incorporated into both the demand history and forecast where the final demand forecast is reduced to account for those conservation savings. The conservation assumptions are provided in Table A.1.

Table A.1 Conservation Assumptions

Year	Conservation (MW)
2016	210
2017	321
2018	579
2019	953
2020	1,363

The demand forecast accounts for the impacts of embedded generation. Capacity projections based on projected generation are combined with historical production functions to generate estimated hourly output. This information is then applied to the demand forecast to determine the need for grid-supplied electricity.

More details on load modelling are described in the IESO document titled "Methodology to Perform Long Term Assessments" (http://www.ieso.ca/Documents/marketReports/Methodology_RTAA_2014feb.pdf).

A.3 Demand Side Resources

There are three main demand management mechanism at the IESO that are modelled as resources: peaksaver PLUS, Demand Response (DR)/ Capacity-Based Demand Response (CBDR) and Dispatchable Loads.

Peaksaver PLUS is a direct load control air-conditioner cycling program, water heater and pool pump cycling program, while Dispatchable Loads are loads that bid into the market and are dispatched economically like other resources. These are existing programs that have not changed since the last assessment. CBDR is a new market-based mechanism that transitions the previous Demand Response 3 (DR3) program participants into an economically triggered market dispatch. As the contracts for the CBDR expire, participants are going to have the opportunity to offer into the Demand Response Auction. The changes arising from the move to CBDR from DR3 are going to enhance reliability due to the allowance for increased frequency of activations.

Table A.2 Demand-Side Management Assumptions

Year	Gross Demand Management (MW)	Effective Demand Management (MW)
2016	1,305	576
2017	1,305	576
2018	1,305	576
2019	1,305	576
2020	1,430	676

The IESO treats demand response as a resource. As such, to maintain consistency, the impacts of demand response programs are added back to the historical data when forecasting the demand. Effective values of demand management programs are used in MARS to reflect dependable capacity.

Effective capacity available from dispatchable loads is determined based on historical capacity offered, using five-year history, by the participants during peak demand hours. In MARS, dispatchable loads are modeled as EOPs that are available at all times and are represented as monthly values aggregated for each transmission zone.

Effective capacity for DR and peaksaver PLUS are determined based on historical performance of the participants of individual programs. In MARS, both programs are modelled as EOPs that are available at all times and are represented as monthly values aggregated for each transmission zone. However, unlike Dispatchable Load program participants, a monthly limit on number of activations is specified to restrict the number of activations for a month to reflect the contractual obligations.

Price impacts from time-of-use rates and critical peak pricing programs are treated as load modifiers and decremented from the forecast. In Ontario, the participants of demand measure programs also participate in a critical peak pricing program. Therefore, at the time of the annual peak, the demand forecast is reduced for the peak pricing impacts but, concurrently, the available demand response capacity is decremented to ensure that the contribution of these resources is not counted twice.

A.4 Supply-Side Resource Representation

The aggregated installed capacity values as of June 2015 for all generating units expected to be participating in the IESO markets during the assessment period are shown in Table A.3. 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.3 Installed Capacity

Fuel Type	Total Installed Capacity (MW)	Number of Stations
Nuclear	12,978	5
Hydroelectric	8,462	71
Gas/Oil	9,920	29
Wind	2,925	25
Biofuel	455	8
Solar	140	3
Total	**34,880**	**141**

Thermal Resources

Four resource types are modeled as thermal resources: nuclear, gas, oil and biofuel. The capacity values for each unit are based on monthly maximum capacity ratings contained in market participant submissions. Equivalent Forced Outage Rates (EFOR) for existing units are derived using rolling five-year history of actual forced outages. The derived EFORs are then converted to capacity state and transition rate matrices for MARS. For units with insufficient historical data and for new units, EFORs of existing units with similar size and technical characteristics are utilized to model the forced outage rates. The projected EFOR values in the form of weighted average and range by fuel type are provided in table A.4.

Table A.4 Ontario Projected Equivalent Forced Outage Rates

Fuel Type	Weighted Average EFOR	Range of EFOR
Nuclear	8.4%	3 - 20%
Gas/Oil	5.0%	1 - 50%
Biofuel	4.4%	4.4%

Hydroelectric

Hydroelectric resources are modelled in MARS as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity and monthly energy values are determined on an aggregated basis for each transmission zone. Maximum capacity values are based on historical median monthly production and contribution to operating reserve at the time of system weekday peaks. Minimum capacity values are based on the bottom 25th percentile of historical production during hours ending one through five for each month. Monthly energy values are based on historical monthly median energy production since market opening.

For new hydroelectric projects, the maximum capacity value is derived based on the average monthly capacity factor at the time of system peak in the zone where the new project is located. The minimum capacity value and the monthly energy value are calculated using the methodology described above based on the historical production data of a similar sized generator in the zone where the new project is located.

Wind

Wind resources are modelled probabilistically on a zonal basis as Type 1 Energy-Limited Resources with a cumulative probability density function (CPDF). In order to derive the CPDFs, first, the top five demand hour window by month for each shoulder period month and by season for summer and winter periods are determined based on five-year historical demand data. Historical wind production during these top five demand hours is then extracted to determine the median contribution using both simulated and actual wind output data independently. A conservative approach to determining the lower median contribution during top five demand hours is applied to select historical simulated or actual wind output based CPDF for each month or season. Seasonal CPDFs for the summer and winter, and separate monthly CPDFs for the shoulder months are modelled in MARS to represent the capacity contribution of wind resources to the system.

Solar

Solar resources are modelled as load modifiers in MARS with production (MW contribution) calculated from projected installed capacities and hourly solar contribution factors. Hourly solar contribution factors are determined using 10 years of historical simulated data by calculating the hourly median solar contribution by month for each shoulder period month and by season for summer and winter periods. This methodology results in a 24-hour capacity factor that is used to create an hourly solar profile to modify load.

Planned Outages

Planned outages are based on outage submissions from market participants. Sensitivity studies are performed for keeping planned outages 'as is' vs. moving them for when reliance on tie-benefits was needed.

Planned and forced outage impacts for hydro, wind and solar are assumed to be already accommodated in the capacity assumptions used.

Purchase and Sale of Capacity

In May 2015, the IESO signed a 500 MW seasonal firm capacity sharing agreement with Hydro-Quebec. This agreement takes advantage of diversity between provincial electricity demands to support reliability and is in effect for 10 years, starting in December 2015. Quebec can import up to 500 MW in winter months (December to March) and Ontario can import up to 500 MW in summer months (June to September). The energy associated with the capacity agreement will be scheduled through existing market mechanisms.

As of now, Ontario will provide 500 MW of capacity to Quebec in the winter of 2015/2016 and the winter of 2016/2017, which was modelled in the assessment.

Ontario has the option to call on up to 500 MW of capacity from Quebec for summer seasons until 2025. This summer capacity was not relied upon in this Comprehensive Review; however, tie-benefits in general are relied upon for the high growth scenario.

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, as described in *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, as described in *Market Manual 2.11 "18-Month Outlook and Related Information Requirements."*

The 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.

A.5 Transmission System

A.5.1 Representation of Interconnected Systems

There are five systems with which the Ontario system is interconnected: Manitoba, Minnesota, Michigan, New York and Quebec. To model import assistance, an EOP is triggered in each Ontario zone that has an interconnection. The amount of EOP in each of the zones is based on the transfer capabilities of the interconnection.

To model the firm contract of 500MW with Quebec, Quebec is created in MARS with a transmission line interface to Ottawa. This transmission line interface is limited to a maximum transfer capability of 500 MW. To model conservatively, over the winter months of 2015/2016 and 2016/2017, a 500 MW load in Quebec is to represent Ontario's firm capacity export contract.

The 2011 NPCC CP-8 study entitled "Review of Interconnection Assistance Reliability Benefits," published in June 2011 assessed that approximately 3,690 MW of interconnection assistance is reasonably available to the Ontario system by 2015. The expected capacity values used in this study vary, depending on Ontario needs, but are always subject to the limitations of the transmission interconnections outlined in Table A.5. Limits apply year-round except where seasonal ratings are indicated.

Table A.5 Ontario Interconnection Limits

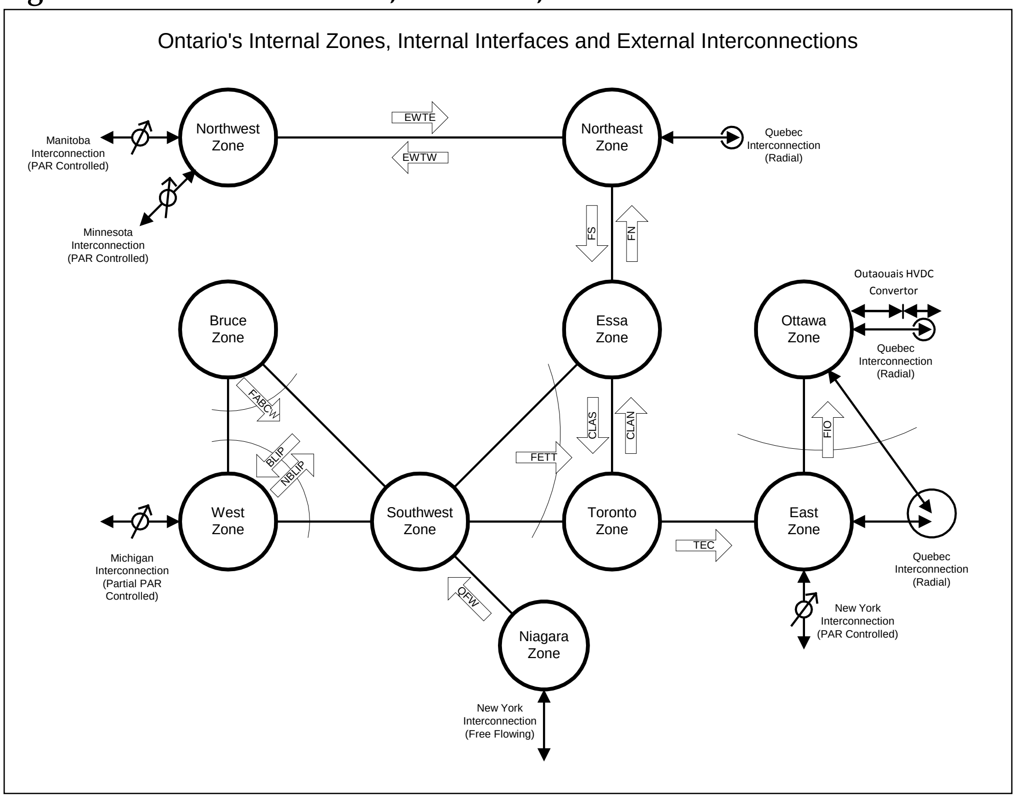
Interconnection	Limit - Flows Out of Ontario MW		Limit - Flows Into Ontario MW	
Manitoba – Summer*	**288**	(3)	**356**	(3,5)
Manitoba – Winter*	**300**	(3)	**368**	(3,5)
Minnesota	**150**		**100**	(3)
Québec North (Northeast) – Summer*	**95**		**65**	
D4Z	0	(4)	65	
H4Z	95	(4)	0	
Québec North (Northeast)– Winter*	**110**		**85**	
D4Z	0		85	
H4Z	110		0	
Québec South (Ottawa) – Summer*	**1570**		**1910**	
X2Y	0		65	
Q4C	120		0	
P33C	0		345	
D5A	200		250	
H9A	0		0	
HVDC	1250		1250	
Québec South (Ottawa) – Winter*	**1590**		**1910**	
X2Y	0		65	
Q4C	140		0	
P33C	0		345	
D5A	200		250	
H9A	0		0	
HVDC	1250		1250	
Québec South (East) – Summer*	**470**		**800**	
B31L + B5D	470		800	
Québec South (East) – Winter*	**470**		**800**	
B31L + B5D	470		800	
New York St. Lawrence – Summer*	**300**		**300**	
New York St. Lawrence – Winter*	**300**		**300**	
New York Niagara – Summer*	**1,650**	(1)	**1,500**	(1,6)
Emergency Transfer Limit - Summer*	**2,160**	(1)	**1,860**	(1,6)
New York Niagara – Winter*	**1,800**	(1)	**1,800**	(1,6)
Emergency Transfer Limit - Winter*	**2,200**	(1)	**2,200**	(1,6)
Michigan – Summer*	**1,700**	(2,3,7)	**1,700**	(2,3,7)
Emergency Transfer Limit - Summer*	**2,250**	(2,3)	**2,250**	(2,3)
Michigan – Winter*	**1,750**	(2,3)	**1,750**	(2,3)
Emergency Transfer Limit - Winter*	**2,350**	(2,3)	**2,350**	(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 LTE ratings and Emergency limits are based on STE ratings.
(3) For real time operation of the interconnection, limits are based on ambient conditions.
(4) Limit based on 0 to 4 km/h wind speed and 30 °C ambient temperature.
(5) Flows into Ontario include flows on circuit SK1.
(6) Flow limits into Ontario are shown here without considering QFW transmission constraints within Ontario.
(7) Flow limits during planned outages can be found in section 4.2.

A.5.2 Internal Transmission Limitations

The Ontario transmission system is represented by 10 interconnected zones with transmission limits between the zones explicitly modeled. Figure A.1 provides a pictorial representation of Ontario's 10 zones. The limits modeled are the operating security limits (OSL) specified for each interface and any projected limit increase due to future transmission system enhancements is appropriately represented.

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



Northwestern Ontario is connected to the rest of the province by the double-circuit, 230 kV East–West Tie. The primary type of generation within the northwest is hydroelectric. Strong local load growth is forecasted as a result of an active mining sector in the region. To address load growth, additional capacity is required to maintain reliable supply to this area under the wide range of possible system conditions. The expansion of the East–West Tie with the addition of a new 230 kV double circuit transmission line is going to provide reliable long-term supply to the Northwest. The line is anticipated to be in-service in December 2020. The 2020 in-service date is revised from 2018 as indicated in the 2014 Long Term Relibility Assessment (LTRA) review due to slower than anticipated near-term load growth. Additional options are being developed to address interim needs should load growth occur sooner than forecast.

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