



Power to Ontario.
On Demand.

Ontario Reserve Margin Requirements

2011-2015

Issue 1.0

REPORT

This report provides Ontario's Reserve Margin Requirements to meet the NPCC resource adequacy criteria over the next five years.

Disclaimer

The posting of documents on this Web site is done for the convenience of *market participants* and other interested visitors to the *IESO* Web site. Please be advised that, while the *IESO* attempts to have all posted documents conform to the original, changes can result from the original, including changes resulting from the programs used to format the documents for posting on the Web site as well as from the programs used by the viewer to download and read the documents. The *IESO* makes no representation or warranty, express or implied, that the documents on this Web site are exact reproductions of the original documents listed. In addition, the documents and information posted on this Web site are subject to change. The *IESO* may revise, withdraw or make final these materials at any time at its sole discretion without further notice. It is solely your responsibility to ensure that you are using up-to-date documents and information.

This document may contain a summary of a particular *market rule*. Where provided, the summary has been used because of the length of the *market rule* itself. The reader should be aware, however, that where a *market rule* is applicable, the obligation that needs to be met is as stated in the “Market Rules”. To the extent of any discrepancy or inconsistency between the provisions of a particular *market rule* and the summary, the provision of the *market rule* shall govern.

Document ID	IESO_REP_0684
Document Name	Ontario Reserve Margin Requirements
Issue	Issue 1.0
Reason for Issue	To meet the requirements of section 8.2 of the IESO's ORTAC
Effective Date	December 20, 2010

Document Change History

Issue	Reason for Issue	Date
1.0	To meet the requirements of section 8.2 of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC)	20-Dec-2010

Related Documents

Document ID	Document Title

This page is intentionally left blank.

Table of Contents

Table of Contents	i
List of Tables	ii
Table of Changes	iii
1. Executive Summary	1
2. Methodology	2
3. Results	4
Appendix A: Key Modeling Assumptions	A-1
A.1 Generation Resources	A-1
A.2 Planned Outages	A-1
A.3 Transmission Limits (Interface and Zonal).....	A-2
A.4 Demand Forecast	A-2
A.5 Emergency Operating Procedures.....	A-2
References	R-1

List of Tables

Table 1: Reserve Margin Percentage by Year.....	1
Table 2: Basecase Reserve Margins and Initial LOLE.....	3
Table 3: Summary of Reserve Margins to meet Target LOLE	4
Table A1: Annual Energy and Peak Demand including impacts of Conservation	A-2
Table A2: Emergency Operating Procedures and their Aggregate Impact.....	A-3

Table of Changes

Reference (Section and Paragraph)	Description of Change

This page is intentionally left blank.

1. Executive Summary

Through the annual release of the “Ontario Reserve Margin Requirements”, the IESO reports the operational planning reserves (“reserve margin”) needed in Ontario over the following five years. This report fulfills the requirements of Section 8.2 of the IESO’s “Ontario Resource and Transmission Assessment Criteria”¹. The calculated reserve margins were determined in accordance with the NPCC² resource adequacy design criteria stated in the NPCC Regional Reliability Reference Directory #1 (Original document: December 1, 2009).

Reserve margin is the amount of supply resources in excess of demand that is required to meet the reliability criteria of annual loss of load expectation (LOLE)³ of 0.1 days per year. It is expressed as a percentage of annual peak demand and represents the reserve level needed to meet this resource adequacy criterion.

The IESO derives the annual reserve margins using a probabilistic multi-area simulation program that includes detailed load and generation information and simplified transmission models of the Ontario system. For this study, Ontario’s resource self-sufficiency is being assessed, so imports were not relied upon in the calculation of reserve margins. Consequently, the study did not model the five external areas that are interconnected to Ontario.

Table 1 presents the results of the study.

Table 1: Reserve Margin Percentage by Year

Reserve Margin [%]	2011	2012	2013	2014	2015
Available ⁴ resources required above peak demand (%)	21.3	21.8	18.7	18.7	19.8

¹ IMO_REQ_0041 “Ontario Resource and Transmission Assessment Criteria” is available from www.ieso.ca

² Northeast Power Coordinating Council (www.npcc.org)

³ LOLE is a common reliability index used to assess generating capacity adequacy. It represents the number of days per year, on average, in which the load exceeds the available generating capacity, and hence, there is an expectation that firm load will be disconnected to resolve resource deficiencies.

⁴ Available capacity is the installed capacity minus allowances made for planned outages and the capacity of energy-limited resources. See Appendix A for assumptions on generation resources.

2. Methodology

The guidelines for calculating the annual reserve margins are provided in Appendix D of the NPCC Regional Reliability Reference Directory #1, “*Guidelines for Area Review of Resource Adequacy*”. This directory document also defines the acceptable level of risk for disconnecting firm load to resolve resource deficiencies:

“Each Area’s probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation [LOLE] 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 Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.”

In this study, the reserve margin is the minimum amount of supply resources in excess of the demand during the most challenging period of the year, required to maintain an annual loss of load expectation (LOLE) of approximately 0.1 days per year. It is expressed as a percentage of *demand* at the time of the most challenging period.

The most challenging period of the year is the time where the highest LOLE is assessed to occur and would usually be expected to occur at the time of system peak. However, this may not necessarily be the case if planned resource outages or other system conditions significantly reduce the resources available to supply the demand over a particular period outside the peak.

In deriving the annual reserve margins, the IESO used General Electric’s Multi-Area Reliability Simulation (MARS)⁵ program, a probabilistic simulation program that is widely used within NPCC and the industry.

The IESO’s MARS model included detailed load and generation information, and a simplified transmission representation of the Ontario system. This model could also include simple representations of the five external areas to which Ontario connects. For this report, however, imports were not relied upon in the calculation of reserve margins so these external areas were not modeled.

To accurately reflect available capacity during the most challenging period of the year, the MARS program is capable of modeling scheduled and unscheduled generation outages, energy and capacity limitations of variable generation resources, transmission constraints, as well as capacity and/or load relief from emergency operating procedures (EOPs). Demand uncertainty that results from the variability of the weather conditions that drive demand is also capable of being modeled. All of these factors have been considered in the calculations contained herein.

For each study year, an initial simulation was run with specific basecase assumptions for available capacity. LOLE results were then compared to the NPCC criterion of 0.1 days/year to assess whether the basecase system met the NPCC criterion. These initial LOLE values expressed in days per year are recorded in Table 2.

⁵ http://www.ge-energy.com/prod_serv/products/utility_software/en/ge_mars.htm

Table 2: Basecase Reserve Margins and Initial LOLE

	2011	2012	2013	2014	2015
LOLE	0.013	0.001	0.000	0.000	0.002
Total Available Capacity	30,239	31,527	31,998	31,983	29,150
Peak Demand	23,463	23,316	22,823	22,545	22,393
Reserve Margin (MW)	6,776	8,211	9,175	9,438	6,757
Reserve Margin (%)	28.9%	35.2%	40.2%	41.9%	30.2%

A cursory review of these results reveals that Ontario comfortably satisfies the NPCC criterion over the planning period assuming planned resources and transmission development projects are delivered on time. The results further suggest that Ontario's planned coal retirement schedule is realizable, provided all replacement resources and associated transmission are commissioned on time. EOPs were not required to achieve these results.

Once this initial assessment was completed, each year's simulation was then re-run in an iterative fashion that adjusted the available resources until an LOLE of 0.1 days/year (+/- 0.005) was achieved. The reserve margin for each study year was then calculated at that particular level of available resources. The results of this procedure and the calculated reserve margins are presented in Section 3 of this report. The key assumptions used to perform the simulations are provided in Appendix A.

For more information on the IESO's MARS simulation approach, see IESO_REP_0266 "Methodology to Perform Long Term Assessments".

– End of Section –

3. Results

Reserve Margin Results

Several resource mix scenarios could be used to meet the LOLE target of 0.1 days/year (+/- 0.005). The results of the simulations based on one possible resource mix in each year are presented in Table 3. They include, for each year of the study period, LOLE, required available resources, projected annual peak demand and reserve margin values expressed in both megawatts and percent of peak demand. These results were achieved without the need to apply EOPs.

Table 3: Summary of Reserve Margins to meet Target LOLE⁶

	2011	2012	2013	2014	2015
LOLE	0.100	0.099	0.097	0.099	0.100
Required Available Capacity	28,454	28,399	27,080	26,750	26,817
Peak Demand	23,463	23,316	22,823	22,545	22,393
Reserve Margin (MW)	4,991	5,083	4,257	4,205	4,424
Reserve Margin (%)	21.3	21.8	18.7	18.7	19.8

The Required Available Capacity is an amount of supply resources equal to the sum of the annual peak demand and reserve margin previously defined in Section 2. The reserve margin represents the minimum required resources in excess of the peak demand, needed to satisfy the NPCC resource adequacy criterion over the next five years. These values take into account demand uncertainty, scheduled and unscheduled generation outages, energy and capacity limitations of variable generation resources and transmission constraints.

The reserve margins over the five-year period fall in the range of 18.7% to 21.8%. For all years of study, the most challenging week of the year coincided with the week of the forecast system peak in July. In view of the longer planning lead times, the scheduling of submitted outages for the years 2012 onwards was optimized to minimize reserve requirements. It should however be noted, that Market Participants may not have submitted *all* planned outages for these years at this time. Reserve margins for these years will therefore benefit from annual review as this information is progressively made available.

In the 2011 and 2012 study years, reserve margins increase by 2.4% and 3.0% respectively over the reserve margins calculated in last year's study. For the 2011 study year, the increase is primarily a result of a change in the demand forecast load shape used in the model, as well as a change in the in-service date assumptions of nuclear units currently undergoing refurbishment. For the 2012 study year, the increase reflects the new in-service date assumption of December 2012 for the Bruce to Milton transmission project. Reserve margins for the 2013 and 2014 study years are only 1.2% and 0.9% higher than last year's study. These modest increases reflect generation assumption changes driven primarily by a larger penetration of variable generation expected under Ontario's Feed-In Tariff (FIT) program.

⁶ These results are based on the assumption that all planned resources and transmission development projects for the next five years are delivered on time.

Conclusion

In conclusion, the study results show that the Ontario system as planned satisfies the NPCC resource adequacy criterion for the next five years assuming all new resources and transmission development projects are delivered on time. Over the planning period, the required reserve margin averages approximately 20.0% without reliance on EOPs.

– End of Section –

This page is intentionally left blank.

Appendix A: Key Modeling Assumptions

A.1 Generation Resources

This study considered all existing resources as of Q3 2010 and new resources that were committed or planned as of September 2010, to come into service over the period 2011 to 2015.

Wind

The wind resources were 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 (3 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-two percent was assumed to be available at the time of winter peak.

Hydroelectric

Hydroelectric resources were modeled in MARS as capacity-limited and energy-limited resources. Minimum and maximum capacity values and monthly energy values were provided for each station. Maximum capacity values were based on median monthly contributions at the time of system weekday peaks plus a contribution to operating reserve. Minimum values and monthly energy values were based on Market Participant submitted data for existing stations. For new hydroelectric projects, the contribution factor was based on the average contribution factors of existing projects on the river system where the new project is to be sited. A contribution factor of 71% of installed capacity was used for new hydroelectric projects.

Thermal Resources

Five resource types were modeled as thermal resources, viz. nuclear, coal, gas, oil and biomass. The capacity values for each unit were based on monthly maximum capacity ratings contained in Market Participant submissions. Equivalent Forced Outage Rates (EFORs) for both new and existing units were based on five-year history of actual forced outages. For units with insufficient historical data, EFORs supplied by Market Participants were used in the study.

Interconnection Support

Although the NPCC criterion for resource adequacy assessments allows for reliance on interconnection support, imports from Ontario's five interconnected neighbours were not considered in this analysis. This is consistent with the approach used in the development of other IESO reliability assessments (e.g. 18-Month Outlook and the Ontario Reliability Outlook), where imports are not relied upon to meet peak demand in the planning timeframe but rather left as an additional resource to be used in real-time operations, as required.

A.2 Planned Outages

Planned outages were in general based on outage submissions from Market Participants as of April 21, 2010. Planned outages for 2011 were modeled precisely as submitted by Market Participants within the limitations of the MARS software. In subsequent years, the timings of planned outages were adjusted, so

long as it was reasonable, in situations where overlapping outages result in significant reductions in system reserve and consequent increases in system LOLE.

For those generating units with no specified outages over the planning period, the planned outages were based on forecast Planned Outage Factors (POFs) submitted by Market Participants and/or a generic outage plan derived from historic outage patterns of existing units. Planned outage impacts for hydro and wind were assumed to be already accommodated in the capacity assumptions used.

A.3 Transmission Limits (Interface and Zonal)

For 2011, all transmission limits among the Ontario zones were modeled consistent with the IESO's 18-Month Outlook published on May 20, 2010. From 2012 to 2015, increases in the FABC limit are expected for Bruce A units 1 and 2 coming in-service, and a new FABC limit in December 2012 for the completion of the 500 kV Bruce-Milton line. Increased limits on the NBLIP and CLAS interfaces are also expected with the completion of the Bruce-Milton line. Transmission enhancements in the Northeast zone to be completed in 2011 are expected to increase the FS limit.

A.4 Demand Forecast

In the MARS program, demand was modeled as an hourly profile for each day of each year of the study period. In the present study, the modeled demand already takes into account the effects of target conservation programs, as well as the contribution of embedded generation resources. The methodology used to generate these forecasts is described in Reference 2. The assumptions are consistent with those applied in preparing the forecast for the 18-Month Outlook published on May 20, 2010. An allowance for load forecast uncertainty was also modeled as described below.

Table A1: Annual Energy and Peak Demand including impacts of Conservation

Year	Demand Forecast	
	Energy (TWh)	Peak (MW)
2011	143.6	23,463
2012	140.4	23,316
2013	138.7	22,823
2014	138.0	22,545
2015	136.7	22,393

Load Forecast Uncertainty (LFU)

Load forecast uncertainty (LFU) arises due to variability in the weather conditions that drive future demand levels. LFU was modeled in MARS through the use of probability distributions. These distributions were derived from observed historical variation in weather conditions that are known to effect demand, viz. temperature, humidity, wind speed and cloud cover. For each of the five years of study, LFU distributions were developed for every month to account for demand uncertainty.

A.5 Emergency Operating Procedures

Emergency Operating Procedures are available to deal with potential shortfall in reserve in the operating time frame, as summarized below. These procedures include reductions in operating reserves, voltage reductions and public appeals. This approach is approved for operational planning as indicated in the

NPCC Directory #1. As part of this assessment, assistance from Emergency Operating Procedures was not required.

Table A2: Emergency Operating Procedures and their Aggregate Impact

EOP Measure	EOP Demand Reduction	
	% of Demand	MW
Operating Reserve (OR)		-1553
Public Appeals	1.0	
No 30-minute OR		473
No 10-minute OR		1080
Generator Stretch Capability		216
3% Voltage Reduction	1.5	
5% Voltage Reduction	1.1	
Total Impact	3.6	216

– End of Section

This page is intentionally left blank.

References

Document Name	Document ID
Ontario Resource and Transmission Assessment Criteria	IMO_REQ_0041
Methodology to Perform Long Term Assessments	IESO_REP_0266
NPCC Regional Reliability Reference Directory #1	NPCC Directory #1

– End of Document –