Power to Ontario.
On Demand.

REPORT

Ontario Reserve Requirements to Meet NPCC Criteria

Supporting Evidence - for Ontario Power Authority Integrated Power System Plan

Issue 1.0

Advice to Reader

The study results in this report are based on information made available to the IESO at the time the assessment was carried out and the assumptions set out in the report. The IESO assumes no responsibility for the accuracy or completeness of such information or the conformity of actual events to the assumptions. Furthermore, the results and conclusions are subject to further consideration due to changes to this information or assumptions, or to additional information that may become available in the future.

The performance expectations of power system facilities were determined based on typical assumptions used in power system planning studies. The actual performance of these facilities during real-time operations will depend on actual system conditions, including ambient temperature, wind speed and facilities loading, and may be higher or lower than those stated in this study.

This report has been prepared solely for use by the Ontario Power Authority (OPA) and the IESO. This report has not been prepared for any other purpose and should not be used or relied upon by any person for any other purpose. The IESO assumes no responsibility to any third party for any use it makes of this report.

Document ID	IESO_REP_0405
Document Name	Ontario Reserve Requirements to Meet NPCC Criteria
Issue	Issue 1.0
Reason for Issue	Supporting Evidence for OPA Integrated Power System Plan
Effective Date	August 3, 2007

Table of Contents

List of Figures

List of Tables

1. Executive Summary

1.1 Introduction

To determine the adequacy of future resources to supply provincial electricity demand, the Ontario Power Authority (OPA) needs to establish appropriate reserve margins for the planning timeframe covered in the Integrated Power System Plan (IPSP). Planning reserve is required to mitigate *reliability risks* associated with operating characteristics of existing and planned resources, as well as uncertainty in various other forecast assumptions. Each risk component is associated with an incremental increase in the reserve requirement which combine to form the overall planning reserve margin requirement.

This report describes the study conducted by the IESO to determine the required reserve necessary to meet the Northeast Power Coordinating Council (NPCC) design criteria for resource adequacy in selected years covered by OPA's IPSP. The OPA provided the guidelines which framed the scope of study, including the years to be examined, the modelling approach and the majority of the data inputs on which the modeling is based.

The uncertainties considered in this study include weather-related demand variability, the intermittent nature of wind and generator forced outage risks. These form a subset of the reliability risks which need to be considered by the OPA in determining the planning reserve. Uncertainties that were intentionally not modelled in this study include forecast assumptions for low water impacts on hydroelectric generation and planned contributions from renewable supply and Conservation not being obtained. These uncertainties will be considered separately by the OPA; accordingly, these were not considered in this study.

For the remainder of this report the term 'reserve margin' will refer specifically to the reserve required to meet NPCC criteria, and not to the overall planning reserve to be established by the OPA.

1.2 Purpose and Main Findings

The IESO conducted this study to determine the reserve margins that are required to meet the NPCC design criteria for resource adequacy for proposed future supply mix scenarios provided by the OPA. These supply scenarios are consistent with those used in the Integrated Power System Plan.

In evaluating required reserve margins, the IESO made the following allowances for risk uncertainty:

- demand forecast uncertainty
- wind-output variability
- planned outages of existing and planned thermal resources
- forced outages of existing and planned thermal resources
- energy and capacity limitations associated with median levels of hydroelectric generation

Four study years (2010, 2016, 2020 and 2026) representing a unique set of supply mix scenarios were examined.

Risk uncertainties were incorporated into the calculation of required reserve margins using a probabilistic approach. General Electric's Multi-Area Reliability Simulation (MARS) program was the primary tool used for this probabilistic analysis. A detailed load and generation representation was modelled in MARS using OPA-provided data. Zonal representations were used for Ontario's ten sub-areas and its interconnections to five neighbouring external control areas.

Reserve margin percentages for the four study years are presented in Table 1. For a given year, the reserve margin percentage represents the amount of capacity required to be available in excess of the forecast peak demand, as a percentage of forecast peak demand.

$$\text{Reserve Margin (\%)} = \frac{\text{Required Available Capacity - Forecast Peak Demand}}{\text{Forecast Peak Demand}} \times 100\%$$

Table 1: Reserve Margin Percentage by Year

	2010	2016	2020	2026
Reserve Margin % (Available Resources required above Peak Demand)	17.0%	13.7%	14.4%	11.9%

It is apparent from Table 1 that reserve requirements in the latter years of the IPSP are forecast to be substantially lower than in the earlier years. This is almost exclusively a result of the improved generator fleet performance expected from the retirement of coal-fired generation and its replacement with gas-fired and nuclear generation with higher availability factors. A sensitivity scenario indicates that a 50 percent increase in nuclear forced outage rates would increase reserve requirements by 1.3 to 2 percent.

These reserve margin values are sufficient to meet the NPCC criteria, provided all proposed resources and Conservation measures are achieved on the timelines envisioned by the OPA. In all four study years, the planned resources identified by OPA exceeded the reserve requirements. Risk analysis to cover in-service delays and abnormally low hydroelectric conditions was specifically excluded from this study and will be addressed separately by the OPA.

– End of Section –

2. Scope and Methodology

2.1 Overview

The NPCC design criteria for system resource adequacy is given in section 3.0 of *NPCC Document A-2: Basic Criteria for Design and Operation of Interconnected Power Systems* (Revision 7 - May 6, 2004). It states that:

> "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 criteria 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 neighbouring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

To ensure the supply mix being considered by the OPA would meet this criteria, IESO conducted studies to determine the amount of required reserve based on the available capacity of future supply mixes proposed for the IPSP for the years 2010, 2016, 2020 and 2026. For the purposes of calculating the reserve margin percentages, the required available capacity at the time of peak demand was used. This value differs from installed (nameplate) capacity for the following resource types:

- Available capacity for hydroelectric resources is a discounted value of installed capacity. It was obtained by taking a 10-year historical average of the energy contributions of hydro at the time of system peaks, plus a contribution to operating reserve.
- Available capacity for wind resources was calculated by OPA to be 20 percent of aggregate installed capacity, based on a 20 year history of simulated wind power output when Ontario demand was within 10 percent of the annual summer peak. IESO and OPA jointly contracted the development of the data from which this result was obtained. Although IESO published reports have assumed a 10 percent capacity contribution from wind, the IESO is in the process of stakeholdering changes, based on the 20 year data set.
- Available capacity for thermal generation is nameplate minus assumed planned outages.
- Conservation measures were considered at the amounts expected by the OPA at time of peak.

Although the required reserve margin is calculated at the time of peak, the computer model used to determine annual LOLE is populated with hourly data which may vary at times from the values at peak demand. Key assumptions and modeling methods were jointly agreed by the IESO and the OPA. These are described in Section 3 and Appendix A.

2.2 MARS – Model Description and Procedure

General Electric's Multi-Area Reliability Simulation (MARS) computer program was used to calculate the standard reliability index of loss of load expectation (LOLE) expressed in days per year. This program is regarded as one of the industry standards for this type of analysis and is used widely in NPCC. The IESO has used this program for six years to perform resource adequacy studies required under NPCC Guideline B-8, *Guidelines for Area Reviews of Resource Adequacy*.

For each study year, an initial simulation was run with the base case assumptions for available capacity; LOLE values were recorded (see Table 2).

Table 2: Basecase Available Capacity (MW) and Initial LOLE

Fuel Type	2010	2016	2020	2026
Nuclear	11,379	9,726	10,941	13,804
Coal	6,434	0	0	0
Gas	7,242	9,924	9,528	9,397
Dual Fuel (Gas/Oil)	1,575	1,575	1,050	525
Oil	60	60	60	60
Biomass	71	450	517	517
Hydro	6,069	6,728	7,476	8,069
Interconnection	500	500	500	500
Wind	290	642	845	881
Conservation	2,175	4,034	4,980	6,003
Total	**35,795**	**33,639**	**35,897**	**39,756**
Initial LOLE	**0.000**	**0.014**	**0.006**	**0.001**

LOLE results were then compared to the NPCC criterion of 0.1 days/year. MARS was re-run in an iterative process by decreasing available gas-fired generation (some coal-fired generation in 2010), until an LOLE of 0.1 days/year (+/- 0.005) was achieved. The required reserve margin for each study year was calculated at the level of available reserves where the LOLE matched the 0.1 days/year target. Results of this procedure and the calculated reserve margins are presented in Section 4.

Appendix A provides a summary description of the MARS program and specific modelling techniques incorporated for this study.

– End of Section –

3. Key Assumptions

In the MARS program, the demand component was modelled as follows:

- an hourly load forecast
- decremented by an hourly profile of expected contribution from Conservation
- decremented by an hourly profile of expected contribution from wind resources

Allowances for load forecast uncertainty, as well as wind output uncertainty were also included in the MARS model. Uncertainty considerations for Conservation were modelled by the OPA external to this study. Table 3 shows annual energy and peak values for the load forecast before and after decrementing Conservation and wind components.

Table 3: Annual Energy and Peak Demand, with and without impacts of Conservation & Wind

Year	Demand Forecast		Demand Forecast (less Conservation & Wind)	
	Energy (TWh)	Peak (MW)	Energy (TWh)	Peak (MW)
2010	159	26,986	147	24,719
2016	168	28,457	141	24,231
2020	176	29,936	142	24,418
2026	192	33,115	153	26,218

3.1 Load Forecast

OPA provided the IESO with hourly load forecasts for each of the years of study. The methodology used to generate these forecasts is described in OPA's IPSP Discussion Paper 2: Load Forecast [1]and a supplemental paper[2]. This base forecast did not include reductions for Conservation measures, the effects of which were included separately.

3.1.1 Load Forecast Uncertainty (LFU)[3]

Load forecast uncertainty (LFU) arises due to variability in the weather conditions that drive future demand levels. LFU was modelled 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: temperature, humidity, wind speed and cloud cover. For each of the four years of study, LFU distributions were developed for every month to account for demand uncertainty.

3.1.2 Conservation

Conservation was modelled deterministically as a load modifier, with hourly profiles provided by the OPA. Hourly Conservation profiles were decremented from the load forecast for use in the MARS model.

---

[1] OPA Website - http://www.powerauthority.on.ca/ipsp/Storage/26/2132_Load_Forecast.pdf
[2] OPA Website - http://www.powerauthority.on.ca/ipsp/Storage/33/2849_Load_Forecast_Supplemental_Information.pdf
[3] For more information on the variability of demand due to weather, refer to Section 2.3 of the IESO document *Methodology to Perform Long Term Assessments* at http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2007jun.pdf

3.1.3 Wind

Wind output was modelled deterministically as a load modifier, with hourly wind production profiles provided for each study year by the OPA. Similar to Conservation, the hourly production profiles were decremented from the hourly demand forecasts. The wind profiles were developed by the OPA using the historical twenty-year data set of simulated wind output. The wind profile was constructed to preserve the temporal relationship of wind to demand consistent with the year 2005, the base year used in developing the OPA demand profile. The approach taken by OPA for the wind profile was consistent with one of the methods suggested by IESO.

3.1.4 Wind Uncertainty

The variability in future weather conditions that makes the use of the LFU for demand forecasts necessary also applies to the forecast wind profiles described above. For this reason, wind variability distributions were generated for each month of each study year to account for wind uncertainty. Wind variability and LFU distributions were convolved to form a single distribution for modelling purposes. The methodology for this process is documented in Appendix B.

3.2 Generation Resources

3.2.1 Hydroelectric

Hydroelectric resources are modelled as capacity and energy-limited resources in MARS (see Appendix A). Minimum and maximum capacity values and monthly energy are provided for each station. Maximum capacity values are based on median monthly contributions at the time of system weekday peaks plus a contribution to operating reserve. Minimum values and monthly energies are median values based on market participant submitted data for existing stations. For new hydroelectric projects, the projects are assigned a contribution factor based on the average contribution factors for existing projects on the river system where the new project is sited. Contribution factors ranged from 62 to 80% of installed capacity.

3.2.2 Thermal Resources (Nuclear, Coal, Gas, Oil and Biomass)

These five resource types are modelled as thermal resources. The capacity values for each unit are based on monthly maximum capacity ratings supplied by the OPA and confirmed through market participant submissions. The equivalent forced outages rates (EFOR) for existing and future units were also provided by OPA. These forecast forced outage rates are consistent with IESO short-term data for mature operating units. The weighted average EFOR for each fuel type is shown below in Table 4.

Table 4: Weighted Average EFOR by Fuel Type

Fuel Type	2010	2016	2020	2026
Nuclear	4.5%	3.8%	5.5%	4.2%
Coal	12.8%	-	-	-
Gas	5.0%	5.0%	5.0%	5.0%
Dual Fuel (Gas/Oil)	11.0%	11.0%	11.0%	11.0%
Oil	26.7%	26.7%	26.7%	26.7%
Biomass	5.0%	5.0%	5.0%	5.0%

3.2.3 Interconnection Support

Support from Ontario's 5 interconnected neighbours was set to a maximum of 500 MW of imports in any hour where Ontario generator outages exceeded 500 MW. This is much less than the approximate 4,000 MW aggregate transfer capability of all of Ontario's interconnections. The 500 MW quantity is the maximum import quantity a generator can purchase to cover a planned outage under current market rules. Although NPCC criteria allow for a greater reliance on interconnections than considered in this study, OPA elected to adopt this particular planning approach since, currently, there are no firm power purchase contracts from outside of Ontario that are assumed in its supply mix scenarios. Furthermore, this is consistent with the approach used by the IESO since market opening with respect to reliability assessments (i.e., consideration given to firm transactions only where capacity counted in Ontario is not counted in a neighbouring area). Had there been such firm power purchase agreements included in the OPA's supply mix (e.g., Québec or Manitoba), the IESO would have modelled these resources accordingly.

3.3 Planned Outages

A generic outage plan was used for coal, gas, oil and biomass generation. This plan, which has been used by the IESO for several years, was derived from historic outage patterns of existing units. Nuclear unit planned outages were scheduled for each year based on market participants' forecast submissions. Planned outage impacts for hydro were included in the capacity assumptions used. Wind generator outages were not explicitly modelled.

3.4 Transmission Limits (Interface and Zonal)

All transmission limits among the Ontario zones were removed except for the East-West ties that link the Northwest and Northeast transmission zones. This was done on the assumption that adequate transmission infrastructure, to be identified in the IPSP, would have to be in place for the proposed resource mix to have adequate deliverability. Transmission constraints for the East-West ties were retained to reflect the possibility that constraints might continue in the Northwest throughout the horizon of this first IPSP.

3.5 Emergency Operating Procedures

Emergency operating procedures, including voltage reductions, public appeals, emergency load reduction and others were not included in the studies. Reliance on these procedures in the long-term planning horizon is not consistent with current public expectations of power system reliability.

– End of Section –

4. Results

4.1 Base Case Results

Required reserve margins based on available capacity for each study year are presented in Table 5 These reserve margins are based on IPSP-proposed supply mixes that meet the target LOLE of 0.1 days/year.

Table 5: Target LOLE – Reserve Margin Summary

	2010	2016	2020	2026
LOLE	0.101	0.098	0.100	0.100
Total Available Capacity	31,585	32,349	34,257	37,041
Peak Demand	26,986	28,457	29,936	33,115
Reserve Margin (MW)	4,599	3,892	4,321	3,926
Reserve Margin (%)	**17.0%**	**13.7%**	**14.4%**	**11.9%**

Tables 6 and 7 show the amount of available resources, by fuel type, required to meet the LOLE target of 0.1 days/year. Table 6 reports available capacities in terms of MW, and Table 7 reports available capacities by fuel type as a percentage of total available capacity.

Table 6: Available Resources required to meet Target LOLE (MW)

Fuel Type	2010	2016	2020	2026
Nuclear	11,379	9,726	10,941	13,804
Coal	4,474	0	0	0
Gas	4,992	8,634	7,888	6,682
Dual Fuel (Gas/Oil)	1,575	1,575	1,050	525
Oil	60	60	60	60
Biomass	71	450	517	517
Hydro	6,069	6,728	7,476	8,069
Interconnection	500	500	500	500
Wind	290	642	845	881
Conservation	2,175	4,034	4,980	6,003
Total	**31,585**	**32,349**	**34,257**	**37,041**

Table 7: Available Resources required to meet Target LOLE (% of Total)

Fuel Type	2010	2016	2020	2026
Nuclear	36%	30%	32%	37%
Coal	14%	-	-	-
Gas	16%	27%	23%	18%
Dual Fuel (Gas/Oil)	5%	5%	3%	1%
Oil	~0%	~0%	~0%	~0%
Biomass	~0%	1%	2%	1%
Hydro	19%	21%	22%	22%
Interconnection	2%	2%	1%	1%
Wind	1%	2%	2%	2%
Conservation	7%	12%	15%	16%
Total	**100%**	**100%**	**100%**	**100%**

A summary of the key assumptions driving the reserve margin percentage for each year is given below.

2010: Approximately 4,500 MW (14 percent of overall available capacity) of coal-fired generation is considered to be available capacity. Coal generation is characterized by relatively higher forced outage rates when compared to gas and nuclear generation, and higher planned outage factors when compared to gas generation.

Planned outage assumptions for 2010 reflect extended planned outages for two of Ontario's three nuclear power plants due to scheduled maintenance. This represents the loss of approximately 3,000 MW in both the spring and fall 'shoulder periods'.

These two factors contribute to a significantly higher reserve margin for the 2010 year in comparison to the other study years.

2016: The resource mix in 2016 is characterized by the removal of all coal-fired generation and the lowest contribution of nuclear capacity of the four study years (less than 10,000 MW nuclear, 30 percent of overall available capacity). Gas-fired generation makes up the majority of the difference in available capacity, along with a greater contribution from conservation and demand management initiatives. Gas-fired generation has lower forced outage rates compared to coal; and significantly lower planned outage factors in comparison to both coal and nuclear generation. This key assumption contributes to the lower reserve margin calculated for 2016 versus 2010.

2020: The increase in the reserve margin between the 2016 and 2020 study years can be attributed to the combination of an increase in nuclear generation capacity, in conjunction with an increase in forced outage rates for nuclear generation. Higher forced outage rates are assumed for the two new nuclear units coming into service in 2018 and 2019, and several nuclear units that are returning to service in this timeframe after undergoing refurbishment.

2026: The decrease in the reserve margin in 2026 is the combined result of the continued increase of nuclear generation capacity and a decrease in forced outage rates for the maturing nuclear fleet of generators (see Tables 2 and 4).

4.2 Sensitivity Analysis – Increase of Nuclear EFOR by 50%

The EFOR assumptions used in this study (see Table 4) were based on forecast data supplied by the OPA and through market participant submissions. It is recognised, however, that a deviation from the forecast assumptions for effective forced outage rates (EFOR) can significantly impact reliability and the requirements for planning reserve.

With this in mind, a sensitivity analysis was conducted where the EFOR for all nuclear units were increased by 50% in the MARS model. This blanket increase in EFOR assumptions was made to capture any potential deviations from forecast EFORs. Table 7 shows the increases made to nuclear EFOR.

Table 8: Nuclear EFOR 50% Increase

Year	Nuclear EFOR Assumption		
	Base Case	Increase EFOR	Delta
2010	4.5%	6.8%	+ 2.3%
2016	3.8%	5.8%	+ 1.9%
2020	5.5%	8.2%	+ 2.8%
2026	4.2%	6.3%	+ 2.1%

Based on the increased EFOR values applied to the nuclear units, Table 9 presents the resulting reserve margins calculated for this sensitivity case. The increase in forced outage rate assumptions has resulted in an increase over the reserve margins calculated for the Base Case (Section 4.1). This result would apply equally to changes in forced outage rate to other fuel types.

Table 9: Reserve Margins (%) – Nuclear EFOR Sensitivity Case

	2010	2016	2020	2026
Basecase Reserve Margin % (Available Capacity)	17.0%	13.7%	14.4%	11.9%
Nuclear EFOR Reserve Margin % (Available Capacity)	18.7%	15.0%	16.1%	13.9%
Delta	+ 1.7%	+ 1.3%	+ 1.7%	+ 2.0%

– End of Section –

5. Conclusion

Based on the four study years, representing a unique supply mix in each year, the required reserve margins, calculated based on available resources, ranged from 12% to 17%. These results indicate that the reserve margin is dependent on the reliability of resources associated with a particular supply mix. The reserve margin accounts for weather-related load forecast uncertainty, wind generation uncertainty plus median expected conditions for thermal unit EFORs, hydroelectric capacity and wind capacity.

In all years studied and for the uncertainties described, the OPA supply assumptions provided to IESO exceed the levels required to meet NPCC reserve criteria.

For operational planning purposes within shorter time horizons, just meeting the NPCC criterion may be considered sufficient since frequent forecast updates combined with significant outage flexibility, external economic supply potential (incremental to a very conservative interconnection assumption) and the availability of emergency operating procedures have historically provided sufficient "insurance" against residual supply risk. For capacity planning purposes, where longer term, investment related decisions must be made, additional reserves to cover residual uncertainties and project delays are appropriate. OPA will address the incremental reserve requirements for these aspects separately, then combine them with the IESO identified requirements.

– End of Section –

Appendix A: Multi-Area Reliability Simulation (MARS) Program

General Electric's Multi-Area Reliability Simulation (MARS) program[4] allows assessment of the reliability of a generation system comprised of any number of interconnected pools which in turn may consist of a number of interconnected areas.

Modeling Technique
A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method allows for many different types of generation and demand management options.

In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly generated operating histories of the generating units with the inter-area transfer limits and the 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 and policies that govern system operation.

Reliability Indices
The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily loss of load expectation (LOLE in days/year)
- Hourly LOLE (hours/year)
- Loss of energy expectation (LOEE in MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating Operating Procedures (days/year or days/period)

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty. For the purpose of meeting the NPCC criterion of 0.1 days/year LOLE, only the daily LOLE (with load forecast and wind uncertainty) was calculated in conducting this study.

The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates expected values of LOLE and can estimate each Area's expected exposure to their Emergency Operating Procedures. Scenario analysis can be used to study the impacts of extreme weather conditions, variations in expected unit in-service dates, overruns in planned scheduled maintenance, or transmission limitations.

Resource Allocation Among Areas
The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. This is done by subtracting the load demand from the total available capacity in the area for each hour. If an area has a positive or zero margin, then it has sufficient capacity to meet its load. If the area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

[4] See: http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls. The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

Generation

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

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

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or deterministically as a load modifier (Type 2 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand management impacts are modeled as load modifiers.

For each unit modeled, the installation and retirement dates and planned maintenance requirements are specified. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending 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. The program schedules planned maintenance to levelize reserves on either an area, pool, or system basis. MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs.

<u>Thermal Units</u>

In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as governed by the outages of various unit components.

Because MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

$$\text{TR (A to B)} \quad = \quad \frac{\text{Number of Transitions from A to B}}{\text{Total Time in State A}}$$

If detailed transition rate data for the units is not available, MARS can approximate the transition rates from the partial forced outage rates and an assumed number of transitions between pairs of capacity states. Transition rates calculated in this manner will give accurate results for LOLE and LOEE, but it is important to remember that the assumed number of transitions between states will have an impact on the time-correlated indices such as frequency and duration.

Energy-Limited Units

Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar; the capacity may be available but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically so as to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.

Cogeneration

MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for Monday through Sunday). This load profile can be changed on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

Energy-Storage and DSM

Energy-storage units and demand management impacts are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week which is subtracted from the hourly loads for the unit's area.

Transmission System

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. The transfer limits are specified for each direction of the interface and can be changed on a monthly basis. For reasons described in Section 3.4, transmission limits were removed from the model for this study.

Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

Contracts

Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as one area with excess capacity in a given hour provides emergency assistance to a deficient area.

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis, but they can be curtailed because of interface transfer limits. Curtailable contracts will be scheduled only to the extent that the sending Area has the necessary resources on its own or can obtain them as emergency assistance from other areas.

– End of Section –

Appendix B: Modelling of Wind Uncertainty

Introduction

The purpose of this analysis was to estimate the amount of reserve required to ensure that future supply mixes proposed in the Ontario Power Authority's Integrated Power System Plan satisfy the NPCC's loss of load criterion for a given demand forecast. For this study, the input for forecast demand was decremented by two components:

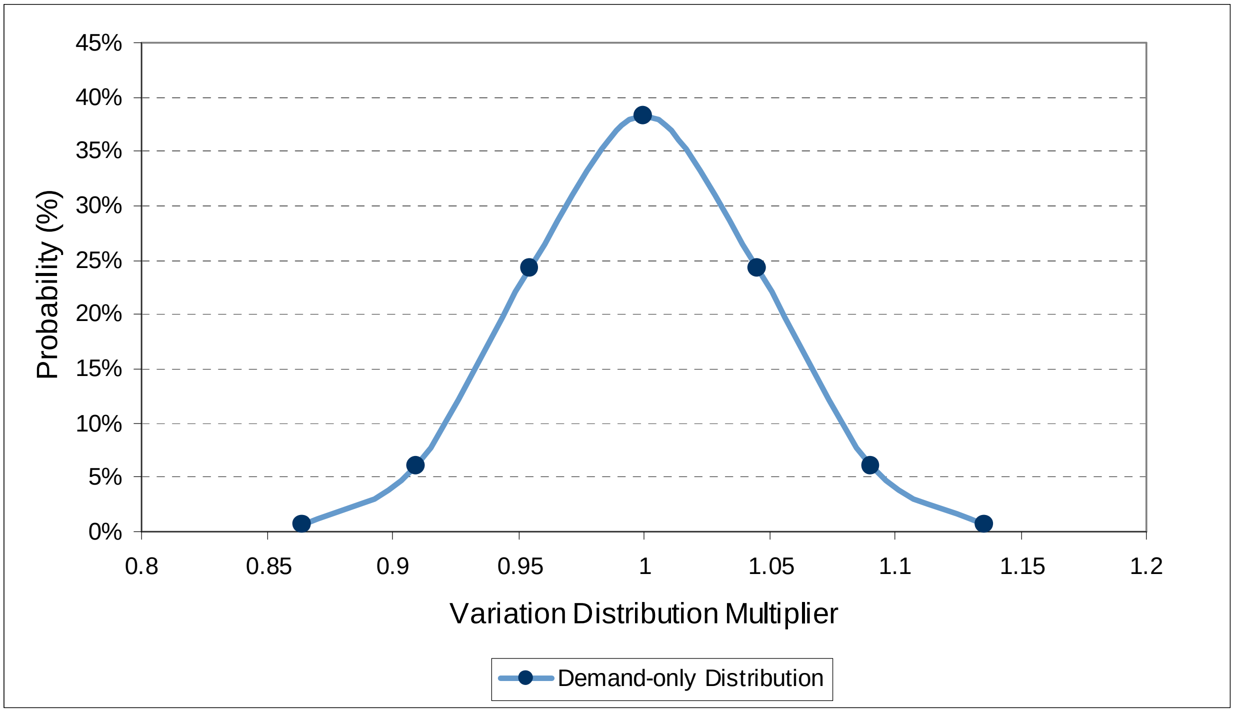
- hourly Conservation measures
- hourly wind generation output

The forecast of demand, Conservation and wind were provided by the Ontario Power Authority (OPA). In order to assess the amount of reserve necessary to maintain the loss of load criterion, a measure of variability in the decremented demand value was required. This measure of variability was used to model weather-related uncertainty in both the demand forecast and the wind output.

Load Forecast Uncertainty

The IESO regularly uses a probability distribution called Load Forecast Uncertainty (LFU) to quantify the volatility in demand due to weather variations. The LFU is represented as a multiplier applied to the normal demand level. This percentage is based on historical variation in the weather conditions that affect demand – temperature, humidity, wind speed and cloud cover. It is assumed that the LFU has a normal distribution about a mean of no-change in demand due to weather variability (see Figure B-1) This mean value is represented by multiplier value 1.00 (see Table B-1, Step 4).

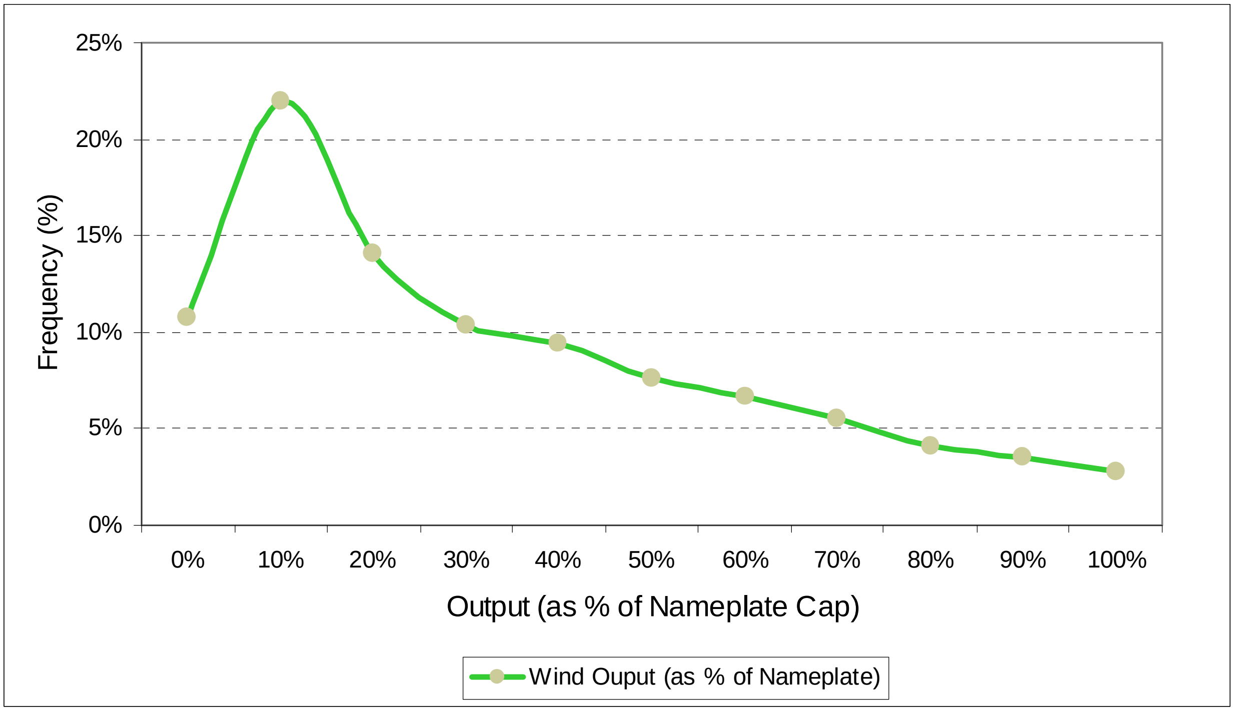
Figure B-1: Load Forecast Uncertainty Generic Distribution



Wind Output Variability

Similar to demand, the amount of electricity generated from wind is also impacted significantly due to volatility in weather-related conditions. Using the wind production data provided by the OPA, a distribution of wind generation was developed for each month of each study year. One significant difference between the LFU and wind distributions lies in their respective shapes. While the LFU is assumed to have a symmetrical (normal) distribution, wind output is characterised by a non-symmetric Weibull distribution (see Figure B-2).

Figure B-2: Wind Output Generic Distribution



Convolving Distributions – Load Forecast Uncertainty and Wind Output Variability

The main issue to be resolved was to determine a method to convolve the two distinct uncertainty distributions. In the MARS model, uncertainty is entered as both a probability and a multiplier for each month of a study year. Considering the demand forecast as the sole input, the LFU is entered into the MARS model as a seven step multiplier with associated probabilities (see Table B-1)

Table B-1: MARS Input Table – Distribution for Demand-only input

Month	7-step Distribution - Variability of Demand Only						
	1	2	3	4	5	6	7
Jan	1.059	1.039	1.020	1.000	0.980	0.961	0.941
Feb	1.065	1.043	1.022	1.000	0.978	0.957	0.935
Mar	1.051	1.034	1.017	1.000	0.983	0.966	0.949
Apr	1.080	1.054	1.027	1.000	0.973	0.946	0.920
May	1.169	1.113	1.056	1.000	0.944	0.887	0.831
Jun	1.144	1.096	1.048	1.000	0.952	0.904	0.856
Jul	1.136	1.091	1.045	1.000	0.955	0.909	0.864
Aug	1.111	1.074	1.037	1.000	0.963	0.926	0.889
Sep	1.147	1.098	1.049	1.000	0.951	0.902	0.853
Oct	1.082	1.055	1.027	1.000	0.973	0.945	0.918
Nov	1.067	1.045	1.022	1.000	0.978	0.955	0.933
Dec	1.068	1.045	1.023	1.000	0.977	0.955	0.932
Probability	0.6%	6.1%	24.2%	38.2%	24.2%	6.1%	0.6%

For the demand decremented by Conservation and wind, a new input table was required such that it represented the convolved distributions of LFU and wind variability. The process of convolving the two distributions is described in the following steps:

1. The probabilities of the seven steps were maintained
2. The multipliers were applied to the raw demand forecast (prior to being decremented for Conservation measures and wind output) to determine a MW measure of LFU
3. For each month of the forecast, the amount of wind generation at the time of the monthly peak was found
4. For each month the distribution of wind generation was represented by a histogram composed of seven bins
5. For each monthly histogram of wind generation, the association probability of each bin level was calculated.
6. The wind production multipliers were calibrated to the amount of wind available at the time of the monthly peak. In this way, the 1.00 multiplier would not be in the middle of the distribution but would appear at the appropriate step determined by the probability associated with the wind production at the time of peak
7. For each step a MW value of wind production could be determined
8. The MW value of wind production was then added to the corresponding MW value of demand uncertainty. This figure was then divided by the final demand to generate the multipliers.

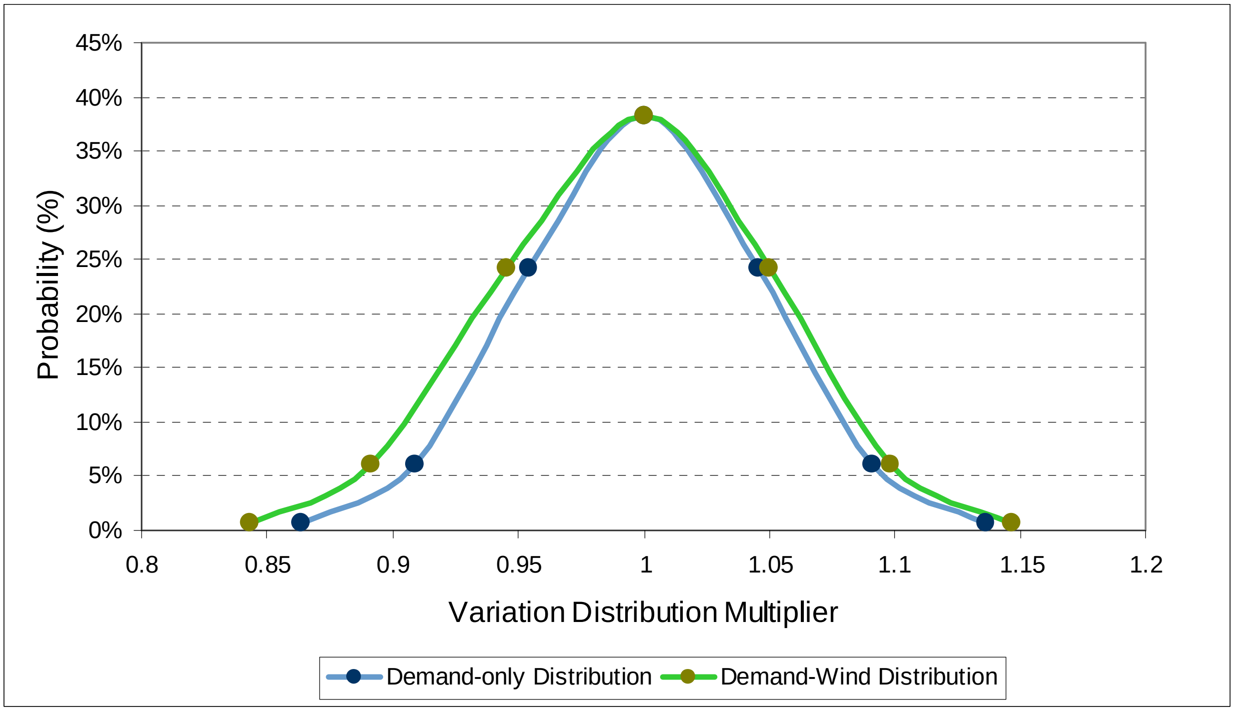
Table B-2 shows the LFU input table for the convolved distributions.

Table B-2: MARS Input Table – Distribution for Demand minus Wind input

Month	7 Step Distribution - Variability of Demand decremented by Wind						
	1	2	3	4	5	6	7
Jan	1.083	1.060	1.033	1.000	0.967	0.941	0.920
Feb	1.084	1.059	1.033	1.000	0.966	0.939	0.915
Mar	1.068	1.049	1.028	1.000	0.971	0.949	0.930
Apr	1.110	1.080	1.044	1.000	0.949	0.915	0.886
May	1.192	1.132	1.069	1.000	0.921	0.853	0.794
Jun	1.154	1.104	1.052	1.000	0.941	0.885	0.834
Jul	1.146	1.099	1.050	1.000	0.945	0.891	0.843
Aug	1.120	1.081	1.042	1.000	0.955	0.911	0.871
Sep	1.166	1.114	1.059	1.000	0.937	0.871	0.818
Oct	1.112	1.081	1.047	1.000	0.953	0.912	0.883
Nov	1.095	1.070	1.040	1.000	0.960	0.932	0.907
Dec	1.092	1.067	1.037	1.000	0.961	0.931	0.907
Probability	0.6%	6.1%	24.2%	38.2%	24.2%	6.1%	0.6%

Not surprisingly, the multipliers are larger for the first three steps and smaller for the last three steps of the distribution. This is logical as the introduction of wind would lead to greater uncertainty and a ‘wider’ distribution. Figure B-3 shows this increase in variability due to wind applied to the July 2010 LFU.

Figure B-3: 7-Step Distribution: July 2010 - Demand-Only vs. Demand minus Wind



– End of Document –

This page is left intentionally blank for double-sided printing purposes.