Agenda Item 4.1

IMO Year 2003 Comprehensive Review of Ontario Resource Adequacy

for the period 2004 - 2008

July 23, 2003

IMO-REP-0137v0.7

Approved by the RCC on November 4, 2003

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1.0 EXECUTIVE SUMMARY

1.1 Major Findings

The Independent Electricity Market Operator (IMO) submits this report to the Northeast Power Coordinating Council (NPCC) in fulfillment of its obligation to conduct a comprehensive review of resource adequacy for the Ontario control area. This report supercedes the review conducted in 2000. The guidelines for the review are specified in the NPCC Document B-8 entitled, "*Guidelines for Area Review of Resource Adequacy*" (Revised: June 28, 2001).

For the first time in a comprehensive review for NPCC, the IMO determined Ontario's level of reliability used the Multi-Area Reliability Simulation (MARS) program, an approach which is already established with NYISO, ISO-NE and NPCC.

Since the last review, about 520 MW of incremental generation capacity has been completed in Ontario, consisting of a large gas-fired facility in southwestern Ontario and a small hydroelectric station in northeastern Ontario. In addition, the IMO has received proposals for 26 generating facilities totaling more than 8,700 MW of additional supply. However, construction has only begun on four of the proposed facilities (totaling 2,216 MW). For those projects that have not begun construction, the IMO considers there is insufficient basis for assuming a commitment to completing the facility. For that reason the IMO does not include these projects in its determination of reliability for this assessment. In April 2005, the IMO assumes the Lakeview Thermal Generating Station (1,148 MW) will cease generating electricity, in compliance with regulatory requirements.

This year's review demonstrates that additional Ontario electricity supply or demand response may be required under certain circumstances to meet the NPCC adequacy criterion throughout the five-year period and to reduce Ontario's dependency on supply from other jurisdictions. New generators and nuclear generators returning from long term outages will improve the reliability of the Ontario power system. If new generators currently under construction and nuclear generators returning from long-term outages are placed in service on schedule, and if additional generators are not retired or taken out of service on a long-term basis beyond those that have currently been identified to the IMO, the requirement for additional supply options could be pushed off toward the end of the study period. However, if the expected generation additions do not take place, or if additional generation is taken out of service, the timing of these requirements could be advanced significantly.

1.2 Major Assumptions and Results

This review covers the period from 2004 to 2008 inclusive. Major assumptions are summarized in Table 1.1 below:

Table 1.1 Major Assumptions

Assumption	Description
Adequacy Criterion	NPCC criterion of 1 day in 10 years, translated into an Loss Of Load Expectation (LOLE) requirement of 0.1 days/year.
Reliability Model	General Electric's MARS program
Load Model	8,760 hourly loads with forecast uncertainty factors
Energy Demand Growth Rate	**Median Demand Growth**: about 1.0 % per annum. **High Demand Growth**: about 1.4 % per annum.
Generating Capacity Additions	**Base Scenario**: - 3,246 MW by the end of 2004. - an additional 515 MW by the end of 2005. - a further addition of 515 MW by the end of 2006. **Sensitivity Scenario**: - 2,731 MW by the end of 2004.
Generating Capacity Retirements	1,148 MW – April 2005
Tie Benefits	1,500 MW modeled (tie capability = 4,000 MW approx.)
Emergency Operating Procedures	Modeled
Unit Availability	Outage plans modeled: - specific for 2004, as submitted by market participants - generic for 2005-2008 based on forecast Planned Outage Factor (POF) from market participants and 10 years of planned outage history data Forced outages modeled: - based on forecast Equivalent Forced Outage Rate (EFOR) from market participants, 10 years of forced outage history data and NERC Generating Availability Data System (GADS) values
Internal and Interconnection Transmission Constraints	Based on IMO normal system operating security limits.

Two resource scenarios were considered for this study. Both incorporate the assumptions listed in Table 1.1 above:

1. The **Base Scenario** assumes that 3,246 MW of generation capacity additions will be placed in service by the end of 2004, with an additional 515 MW in 2005 and 515 MW in 2006.

2. The **Sensitivity Scenario** assumes that only 2,731 MW of generation capacity additions will be placed in service by the end of 2004.

The MARS calculations for the two scenarios were performed in up to three steps. In the first step, the calculations were performed with the assumptions listed above modeled in MARS. Where the resultant annual LOLE exceeded criterion, a second step was performed, wherein the generic outage plan was optimized by the model to yield the same number of planned outage days but distributed outside the summer peak demand period. In the few remaining instances where the LOLE was still exceeded additional capacity was modeled as interconnection assistance. The final step was repeated, with increasing amounts of capacity, until all annual LOLE values became less or equal to 0.1 days/year. MARS results after the first step calculations for the two scenarios are presented in Tables 1.2, 1.3, 1.4 and 1.5.

Table 1.2 Annual LOLE Values – Base Scenario – Median Demand Forecast

Year	LOLE (days/year)
2004	0.007
2005	0.017
2006	0.012
2007	0.021
2008	0.034

Table 1.3 Annual LOLE Values – Sensitivity Scenario – Median Demand Forecast

Year	LOLE (days/year)
2004	0.010
2005	0.063
2006	0.114
2007	0.266
2008	0.349

Table 1.4 Annual LOLE Values – Base Scenario – High Demand Forecast

Year	LOLE (days/year)
2004	0.015
2005	0.040
2006	0.042
2007	0.080
2008	0.129

Table 1.5 Annual LOLE Values – Sensitivity Scenario – High Demand Forecast

Year	LOLE (days/year)
2004	0.020
2005	0.127
2006	0.286
2007	0.681
2008	1.089

Under the Base Scenario (Tables 1.2 and 1.4), MARS results indicate that Ontario can expect to be in compliance with the NPCC resource adequacy criterion with no further action required except in 2008 under the high demand growth case. In the event Ontario experiences high demand growth over the five-year period, the risk level for 2008 can be reduced below the LOLE criterion of 0.1 days/year level (to an LOLE of 0.012 days/year) through a minor redistribution of some scheduled outages out of the summer months (June-August).

MARS results under the Sensitivity Scenario indicate that, starting in 2006 under median demand growth and 2005 under high demand growth, Ontario may expect to require additional supply, in order to meet the NPCC resource adequacy criterion. Following the second step of the MARS calculation, with the generic outage plan assumptions modified to shift maintenance outages out of the summer months of June, July and August, the LOLE results indicate that compliance can be achieved through outage rescheduling in most cases. The two years of exception, 2007 and 2008, occur only under high demand growth assumptions, when a combination of outage rescheduling, generation additions, additional tie-benefit and/or demand response would be required to reduce the risk of insufficient supply below the target level for compliance. Approximately 500 MW of additional tie benefit, supply or demand responses would be required in conjunction with shifting all major outages out of June July and August. IMO, through its routine Outlooks, will closely monitor the situation in these later years, working proactively with stakeholders to achieve an appropriate longer-term response.

- End of Section -

2.0 TABLE OF CONTENTS

2.1 List Of Tables

2.2 List Of Figures

3.0 INTRODUCTION

This report is the comprehensive area review of resource adequacy for Ontario, prepared by the Independent Electricity Market Operator (IMO) and submitted to the Northeast Power Coordinating Council (NPCC) in accordance with NPCC Document B-8, entitled “Guidelines for Area Review of Resource Adequacy" (revised June 28, 2001).

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

The information presented in this report covers the period from 2004 to 2008.

3.1 Reference to Most Recent NPCC Triennial Review

The previous review was submitted by the IMO and was approved at the November 2000 meeting of the Reliability Coordinating Committee. Comparisons between this review and the November 2000, “IMO Year 2000 Triennial Review of Ontario Resource Adequacy” are contained in this report.

3.2 Comparison of This Review and Previous Review

3.2.1 Demand Forecast

Tables 3.1, 3.2 and Figure 3.1 display the winter/summer peak demand forecast in both the 2000 and 2003 reviews. The values forecast in this 2003 review are based on a forecast of the normal weather probability distribution of the demand in each week of the year. The values shown are the 60-minute normal weather peak demands forecast under a median demand growth scenario, as well as under a high demand growth scenario. Similar to the median demand growth scenario, the high demand growth scenario has its own normal weather probability distribution function. The difference between the two scenarios is driven by economic factors, which are provided in Appendix 1.1. The distribution represents weather conditions based on the last 30 years of record. The 2000 forecast values were similarly based on a weekly normalization under median and high growth scenarios. However, the reported peak demands in 2000 were 20-minute values. Besides the change in peak demand reporting format, differences between the two forecasts arise for two main reasons. First, in 2001, the IMO switched from using a modified Ontario Power Generation forecast to using a new forecasting model, Metrix ND, populated with IMO forecast data. Second, the underlying economic projections between the two forecasts have changed over the past two years. The net result is similar year-over-year growth rates but with different initial starting points, especially for the median demand growth scenario.

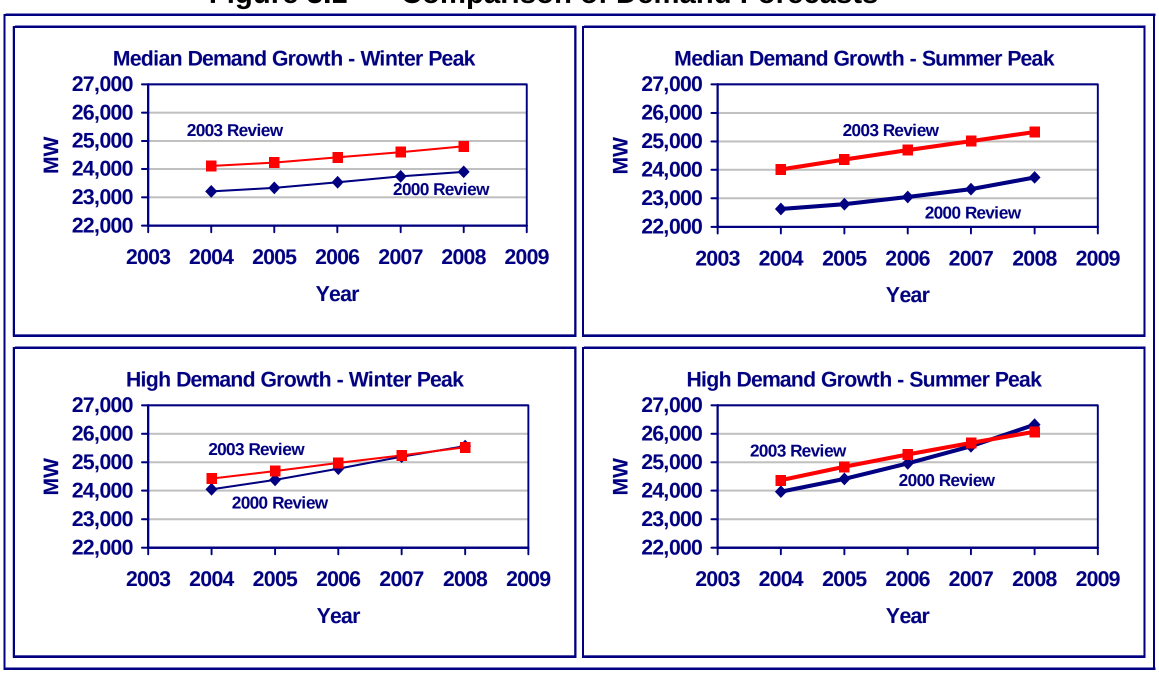
Table 3.1 Comparison of Demand Forecasts – Normal Weather Winter Peak

Year	Normal Weather Winter Peak			
	Median Demand Growth		High Demand Growth	
	2000 Review	2003 Review	2000 Review	2003 Review
2004	23,205	24,112	24,047	24,420
2005	23,338	24,233	24,377	24,690
2006	23,532	24,422	24,772	24,977
2007	23,739	24,603	25,193	25,240
2008	23,903	24,808	25,572	25,523
Average Growth Rate	0.74%	0.71%	1.55%	1.11%

Table 3.2 Comparison of Demand Forecasts – Normal Weather Summer Peak

Year	Normal Weather Summer Peak			
	Median Demand Growth		High Demand Growth	
	2000 Review	2003 Review	2000 Review	2003 Review
2004	22,627	24,014	23,964	24,369
2005	22,795	24,360	24,413	24,845
2006	23,048	24,689	24,965	25,275
2007	23,327	25,005	25,559	25,672
2008	23,737	25,326	26,320	26,072
Average Growth Rate	1.20%	1.34%	2.37%	1.70%

Figure 3.1 Comparison of Demand Forecasts



3.2.2 Resources Forecast

Tables 3.3 and 3.4 indicate the resources forecast to be available to the Ontario system at the time of the seasonal peaks assumed for this review and for the 2000 review. The IMO's current forecast of available resources under the Base Scenario is higher than the 2000 forecast, due mainly to additional nuclear capacity which was not anticipated in 2000. Under the Sensitivity Scenario the current forecast of available resources is slightly lower than the 2000 forecast, starting mid-2005, due mainly to more conservative assumptions for nuclear units returning to service from lay-up. Both scenarios for the 2003 review are influenced by the assumed retirement of 1,148 MW of generating capacity in April 2005. The expectation of this retirement, which developed in 2001, was not considered in the 2000 review.

Table 3.3 Comparison of Available Resource Forecasts – Base Scenario

Year	Winter Peak			Summer Peak		
	2000 Review	2003 Review	Difference	2000 Review	2003 Review	Difference
2004	28,664	29,112	448	28,354	30,620	2,266
2005	28,664	29,838	1,174	28,354	29,142	788
2006	28,664	29,350	686	28,354	29,695	1,341
2007	28,664	30,156	1,492	28,354	29,731	1,377
2008	28,664	29,894	1,230	28,354	29,602	1,248

Table 3.4 Comparison of Available Resource Forecasts – Sensitivity Scenario

Year	Winter Peak			Summer Peak		
	2000 Review	2003 Review	Difference	2000 Review	2003 Review	Difference
2004	28,664	29,112	448	28,354	30,105	1,751
2005	28,664	29,323	659	28,354	28,112	-242
2006	28,664	28,320	-344	28,354	28,150	-204
2007	28,664	28,611	-53	28,354	28,186	-168
2008	28,664	28,349	-315	28,354	28,057	-297

3.2.3 Resource Adequacy Assessment Criterion

For both the 2000 and the current review, the IMO used the assessment criterion described in Section 4.1, which is the same as the NPCC resource adequacy criterion.

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4.0 RESOURCE ADEQUACY ASSESSMENT CRITERION

4.1 Statement of Resource Adequacy Assessment Criterion

The IMO uses the NPCC resource adequacy criterion from Document A-2 to assess the adequacy of resources in the Ontario control area:

> "… resources will be planned in such a manner that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and regions, and capacity and/or load relief from available operating procedures, the probability of disconnecting non-interruptible customers due to resource deficiencies, on the average, will be no more than once in ten years ".

The IMO reports on resource adequacy relative to an NPCC-accepted variation of this criterion, which considers a Loss of Load Expectation of not more than 0.1 days per year. This modified criterion is expected to be formalized in the next version of Document A-2.

4.2 Statement of How the Criterion is Applied

The reliability standard is used to assess the adequacy of available generating resources needed to supply the Ontario Area on an ongoing basis, to identify periods of potential resource deficiency.

Consideration is given to Ontario’s interconnections with Manitoba, Minnesota, Québec, New York and Michigan and the resultant tie-benefits which can be assumed. Scheduled and forced outages to Ontario generators are assessed based on explicit outage submissions by generator owners and more generalized planned outage factors.

Load relief actions that will be taken by the IMO to deal with a potential shortfall in reserve in the operating time frame are summarized below. Load relief from these actions is considered to be constant over the five-year period. It should also be noted that while the list below provides the anticipated order of the control actions, the IMO may initiate control actions at any point in the hierarchy list, and may alter the order in which the control actions are implemented, depending on the specific circumstances. These actions include the following:

- reject outage applications, revoke approved outages, recall outages;
- issue general or public appeal;
- constrain dispatch of resources;
- discontinue commissioning tests;
- dispatch emergency generation (if available);
- purchase emergency energy and request emergency assistance;
- disregard 30-minute operating reserve requirement;
- recall exports;
- implement 3% voltage reduction;
- disregard high-risk limits;

- disregard 10-minute operating reserve requirement;
- implement 5% voltage reduction;
- implement environmental variances;
- operate to emergency condition limits;
- implement Emergency Demand Response Program (if available);
- curtail non-dispatchable load (emergency block or rotational load shedding).

Most of these actions are modeled in the MARS program by evaluating the daily Loss of Load Expectation (LOLE) at various margin states. Table 4.1 summarizes the assumptions regarding the load relief from emergency operating procedures used for this study. Several of the categories above have been aggregated for modeling purposes.

Table 4.1 Emergency Operating Procedures Load Relief Assumptions

EOP Action	Load Relief MW
Price-Sensitive Demand / Utility Surplus	450
Zero 30-min Reserves	441
Voltage Reduction	580
Zero 10-min Reserves	1,139
General Public Appeals	200

4.3 Required Reserve to Meet Criterion

For the purposes of this study, the adequacy of Ontario's existing and planned resources is assessed through calculation of the annual LOLE under all four combinations of resource and demand scenarios, and comparison with the 0.1 days/year target prescribed by the NPCC resource adequacy criterion. In this review, an interconnection tie benefit of 1,500 MW was assumed to be available to Ontario for the five-year period under study.

In IMO's latest annual 10-Year Outlook (IMO_REP_0097), the IMO stipulates reserve requirements for Ontario based on calculations from the IMO's Load and Capacity (L&C) Program. Generation reserve requirements are estimated on a weekly basis; for the five-year period under study, reserve requirements range from 12% to 17% at the time of the seasonal peaks. Higher reserve requirements, up to almost 22%, occur during milder periods which have greater load forecast uncertainty and higher maintenance levels than the peak periods.

4.4 Comparison of IMO and NPCC Criteria

The IMO's reliability criterion for this review is the same as the NPCC criterion.

4.5 Resource Adequacy Studies Done Since the 2000 Review

Adequacy assessments produced by the IMO since the last Area review include numerous 18-Month Outlooks published since the beginning of 2002 on a quarterly basis (semi-annually prior to 2002), and three 10-Year Outlooks published by April of each year since 2001. All of these reports, available on the IMO web site (www.theIMO.com), were submitted to the Minister of Energy and the Ontario Energy Board to meet the requirements of the Ontario Market Rules. Results of the IMO's latest 10-Year Outlook form the basis for this review and are included herein where appropriate.

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5.0 RESOURCE ADEQUACY ASSESSMENT

5.1 Planned Resources Versus Median Demand Forecast

On average over the forecast period, Ontario electrical energy demand is expected to increase by about 1.0% annually under the median demand forecast.

5.1.1 Base Scenario Versus Median Demand Forecast

Table 5.1 shows that under the Base Scenario and median demand growth assumptions Ontario will have adequate resources to meet the NPCC criterion through 2008.

Table 5.1 Annual LOLE Values – Base Scenario – Median Demand Forecast

Year	LOLE (days/year)
2004	0.007
2005	0.017
2006	0.012
2007	0.021
2008	0.034

5.1.2 Sensitivity Scenario Versus Median Demand Forecast

Table 5.2 shows that under the Sensitivity Scenario and median demand growth assumptions Ontario may have to secure additional resources as early as 2006, in order to meet the NPCC criterion through 2008. Following the second step of the MARS calculations, with the generic outage plan assumptions modified to shift maintenance outages out of the summer months of June, July and August, results indicate that compliance can be achieved through outage rescheduling ($LOLE_{adjusted}$ = 0.049 days/year in 2008).

Table 5.2 Annual LOLE Values – Sensitivity Scenario – Median Demand Forecast

Year	LOLE (days/year)
2004	0.010
2005	0.063
2006	0.114
2007	0.266
2008	0.349

5.2 Planned Resources Versus High Demand Forecast

On average over the forecast period, Ontario electrical energy demand is expected to increase by about 1.4% annually under the high demand forecast.

5.2.1 Base Scenario Versus High Demand Forecast

Under the Base Scenario and high demand growth assumptions, the MARS calculation results shown in Table 5.3 indicate that Ontario will have adequate resources to meet the NPCC criterion through 2007. Some minor outage rescheduling in 2008 would be sufficient to reduce the risk below the target level of 0.1 days/year (LOLE $_{adjusted}$ = 0.012 days/year in 2008) .

Table 5.3 Annual LOLE Values – Base Scenario – High Demand Forecast

Year	LOLE (days/year)
2004	0.015
2005	0.040
2006	0.042
2007	0.080
2008	0.129

5.2.2 Sensitivity Scenario Versus High Demand Forecast

MARS results for the Sensitivity Scenario under high demand growth, shown in Table 5.4, indicate that, starting in 2005, Ontario would require additional supply in order to comply with the NPCC resource adequacy criterion. Following the second step of the MARS calculations, with the generic outage plan assumptions modified to shift maintenance outages out of the summer months of June, July and August, results indicate that compliance can be achieved in 2005 and 2006. In 2007 and 2008, a combination of outage rescheduling, generation additions, additional tie-benefit and/or demand response would be required to reduce the risk of insufficient supply below the target level for compliance (LOLE $_{adjusted}$ = 0.201 days/year in 2008, based on outage shift only). Approximately 500 MW of tie benefit, supply or demand responses would be required in conjunction with shifting all major outages out of June July and August in order to achieve compliance.

Table 5.4 Annual LOLE Values – Sensitivity Scenario – High Demand Forecast

Year	LOLE (days/year)
2004	0.020
2005	0.127
2006	0.286
2007	0.681
2008	1.089

5.3 Contingency Mechanisms for Managing Demand and Resource Uncertainties

On an annual basis, the IMO prepares 10-Year Outlooks that provide the IMO Board of Directors, the Minister of Energy and the Ontario Energy Board, as well as market participants, with information about the requirements for generation and transmission capacity in Ontario. These Outlooks consider elements of demand and resource uncertainty. In particular, when considering future resource additions, the IMO takes a conservative approach and only includes projects which are under construction. To date, however, the IMO has received proposals for 26 generating facilities totaling more than 8,700 MW of additional supply; although only four are under construction (2,216 MW), several others are either in an advanced stage of the pre-construction approval process or require a short timeframe to complete construction.

If current market incentives prove insufficient to motivate construction of additional generators or development of comparable demand response programs, several courses of action are available to restore Ontario's demand - resource balance.

At any time, the IMO Board of Directors can initiate implementation of a capacity reserve market in order to attract additional generating capacity into the market. The mechanisms for this process would be approved by the Minister of Energy and formalized in the Market Rules.

Since 2002, on a year by year basis, the IMO has implemented an Emergency Demand Response Program (EDRP). For 2002 approximately 340 MW of load was contracted under this program. The 2003 response is expected to be at least as much and possibly more than 100 MW higher. The relief from the EDRP has not been modeled in this review because of the year by year nature of the program.

For 2003, the Ontario Government, through the Ontario Electricity Financial Corporation, issued a Request for Proposal for emergency generators to be installed by the summer of 2003 to augment supply over the summer peak and into 2004. This measure is expected to yield approximately 400 MW of supply, most of it by mid-July. With uncertainties around the exact amount of capacity which will be built, along with the timing and life-span of units, the IMO has chosen not to model these generators for this review.

Every quarter, looking from one month in the future out 18 months, the IMO assesses the integrated 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 fail to proactively reschedule outages to mitigate concerns, the IMO may veto outages in the near-term to ensure sufficient capacity is available to meet non-dispatchable demand. The relief which can be expected from this measure can amount to up to 2,600 MW over the summer months and more during other periods. For the years where the LOLE exceeded 0.1 days/year in Sections 5.1 and 5.2, the generic outage plan assumptions were modified to shift maintenance outages out of the summer months of June, July and August. This shift resulted in acceptable LOLE's for all cases except for 2007 and 2008 under the Sensitivity Scenario combined with high demand growth.

Although a tie benefit of only 1,500 MW has been assumed for purposes of this review, the coincident interconnection capability is normally in the range of 4,000 MW. Data from the first year of market operation reveals imports averaged more than 2,300 MW whenever demand exceeded 23,000 MW. Further study will be conducted over the next year to determine whether the IMO tie benefit assumption should be raised.

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6.0 PLANNED RESOURCE CAPACITY MIX

6.1 Reliability Impacts of Forecast Net Installed Capacity by Fuel Type and Environmental Restrictions

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

The maximum generation from fossil fuels must be controlled within regulated limits for acid gas emissions. These acid gas emission amounts have been controlled in the past by use of lower sulfur coal, and use of oil/gas fired generation options. Environmental considerations may result in either additional retirements over those already assumed, or lower utilization factors for some generating units. Lakeview coal-fired generating units are already assumed to retire by April 2005 as a result of the government regulation requiring the plant to cease burning coal. A recent report[1] issued by the government of Ontario recommends the retirement of Atikokan and Thunder Bay generating units by July 1, 2005. Even if no additional retirements occur over the next five years, fossil fuel emission limits can be expected to influence installation of emission abatement measures, conversion to other fuels, or possibly lower plant utilization rates.

In the event of additional restrictions on coal-fired generation, or if some returning nuclear generation is not successfully restored to service, a combination of generation, transmission or demand responses may be needed to ensure Ontario reliability.

In excess of 8,700 MW of proposed generation has been submitted to the IMO for connection assessment. The majority of this new generation (about 6,000 MW) is gas-fuelled. From a supply perspective, the IMO monitors generator unavailability arising from fuel related issues and determines the need and amount of capacity discounts to be included in the IMO Outlooks.

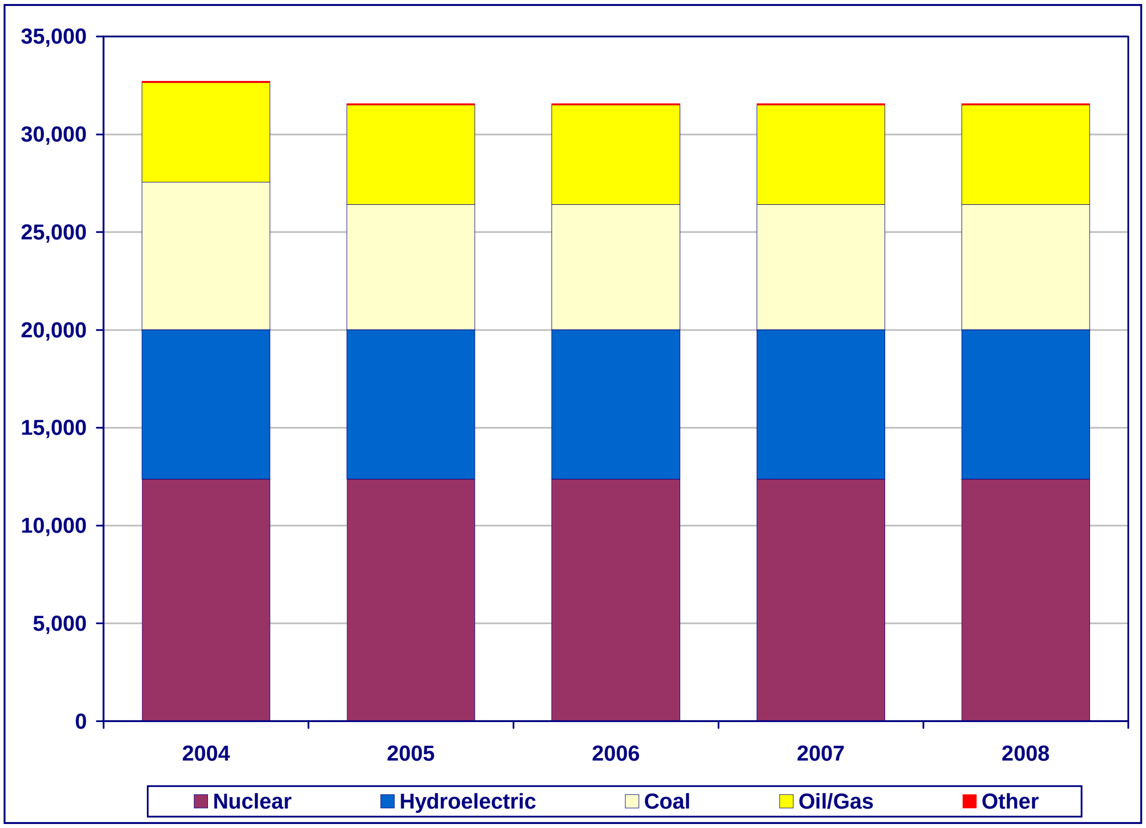
Table 6.1 and Figure 6.1 show the net installed capacity mix by the end of each year in the study period.

[1] Select Committee on Alternative Fuel Sources - Final Report, 3rd Session, 37th Parliament, 51 Elizabeth II.

Table 6.1 Ontario Capacity Mix By Fuel Type

Fuel Type \ Year	2004	2005	2006	2007	2008
Nuclear (%)	37.8	39.2	39.2	39.2	39.2
Coal (%)	23.1	20.3	20.3	20.3	20.3
Oil/Gas (%)	15.6	16.1	16.1	16.1	16.1
Hydroelectric (%)	23.3	24.2	24.2	24.2	24.2
Other (%)	0.2	0.2	0.2	0.2	0.2

Figure 6.1 Ontario Capacity Mix by Fuel Type



6.2 Available Mechanisms To Mitigate Reliability Impacts Of Capacity Mix And Environmental Restrictions

Any increase in the capacity-mix diversity would have beneficial effects on supply flexibility and environmental restrictions. Over the past year, almost 1,300 MW of new wind-powered generation proposals have been submitted to the IMO for connection assessment and approval. Many of these are expected to begin construction later this year and commence generating in 2004 and 2005. Although the amount of dependable wind generation capacity must be substantially discounted from the nameplate value, wind energy can successfully reduce the utilization of other potentially energy-limited resources.

Certain generators are being fitted with emission abatement facilities this year to maintain coal-fired supply while meeting all current environmental restrictions.

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

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APPENDIX

APPENDIX A - DESCRIPTION OF RESOURCE RELIABILITY MODEL

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

A sequential Monte Carlo simulation forms the basis for MARS. In this simulation, a chronological system evolution is developed by combining randomly generated operating states for the generating units with inter-zone transfer limits and hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules that govern system operation. Various measures of reliability can be reported using MARS, including the Loss of Load Expectation (LOLE) 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 (LFU). The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates LOLE values and can estimate the expected number of times various emergency operating procedures will be implemented in each zone and pool.

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

1.1 LOAD MODEL

1.1.1 Description And Basis Of Period Load Shapes

The Ontario power system was modeled as a pool composed of ten zones. Figure A.1 provides a pictorial representation of Ontario’s ten zones. Hourly loads for each of the ten Ontario zones were modeled, for the study period.

The IMO uses a multivariate econometric model to forecast energy and peak demand on the IMO-controlled grid. The model uses three sets of forecast drivers: calendar variables, economic conditions and weather effects. Weather is captured using normal weather, which represents the average weather observations based on 30 years of historical data. A consensus of publicly available, provincial forecasts are used to determine the economic drivers in the forecast. The forecast used for this study was based on load, weather and economic data through to the end of October 2002. Two demand growth scenarios (median and high) were developed reflecting differences in two principal economic factors, employment and housing. For the median economic growth scenario, the economic factors showed annual average growth of 1.5% over the 2004-2008 time frame. The high growth scenario had the economic factors growing at a much stronger 2.3% per annum over the same period. Under the high growth scenario (compared to the median) there are 345,000 more people forecast to be employed in 2008 and just under 200,000 more homes (housing stock).

1.1.2 Load Forecast Uncertainty

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

1.1.3 Demand-Side Management

The peak demand values include loads that may be dispatched off during high price periods, loads that may simply reduce in response to high prices, and loads that may otherwise be reduced in the case of a shortfall in reserves. For the purposes of resource adequacy assessments, the IMO assumes that 300 MW of price-responsive demand is available, based on operational experience. This amount was modeled in MARS as part of the emergency operating procedures (EOP).

1.2 RESOURCE REPRESENTATION

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

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

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

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

1.2.1 Unit Ratings

1.2.1.1 Definitions and Values

The aggregated net installed capacity values for all existing generating units registered in the IMO-administered markets, as of May 2003, are shown in Table A.1.

Table A.1 Net Installed Capacity - As Of May 2003

Resource Type	Total, MW	# of Stations
Nuclear	10,836	4*
Coal	7,546	5
Oil/Gas	4,416	24
Hydroelectric	7,636	59
Miscellaneous (wind, waste, etc.)	66	2
Total	30,500	94

* The number of operating nuclear stations will increase to five with the operation of the first Bruce A unit.

Seasonal (January and July) output capabilities, submitted by market participants were input to MARS. These capabilities take into account any output deratings given by equipment or ambient limitations, and environmental restrictions.

Hydraulic station minimum and peak outputs, and monthly energy production capabilities submitted by market participants are based on median (exceeded 50 % of the time) river flows, determined from about 30 years of record.

1.2.1.2 Procedure for Verifying Ratings

The Ontario Market Rules permit various tests to be carried out by the IMO. Explicit test procedures for verifying generator ratings are currently under development. For this review, the IMO used ratings submitted by market participants; these were verified through comparison with revenue and operational metering.

1.2.2 Unit Unavailability Factors

1.2.2.1 Type Of Unavailability Factors Represented

Equivalent Forced Outage Rates (EFOR) for each unit are used that reflect both forced outages and periods of derated output. These were based on unit specific data supplied by market participants. Historic information and forecast future performance are combined to derive the rates.

Planned maintenance was modeled on a unit basis. For the first year of study, explicit outage plans were modeled, as submitted by market participants. For the remainder of the study period, representative outage plans were used. The assumptions with respect to planned maintenance amount to the equivalent of a weighted-average planned outage factor of about 13%.

1.2.2.2 Source Of Unavailability Factors Represented

EFOR and POF values used in this study are regularly provided by market participants to the IMO for its routine Outlooks. Actual outage history is obtained from the IMO's Integrated Outage Management System. For a few small units (below the reporting threshold stipulated by the IMO) the IMO uses NERC GADS data.

1.2.2.3 Maturity Considerations and In-Service Date Uncertainty

Unit maturity was considered in this study. For new generating units, higher EFOR values were assumed for an immaturity period of up to three years from the in-service date. Table A.2 shows the immaturity EFOR values used for the various types of new generation assumed in this study.

Table A.2 Immaturity EFOR Values

Fuel Type	Immaturity EFOR (%)
Nuclear	8 - 13
Gas	20 - 40

Unit in-service date uncertainties were taken into account through the Sensitivity Scenario, in which the possibility that some of the planned generating units may not come in service within the five-year period.

1.2.2.4 Tabulation of Typical Unavailability Factors

The range of forecast EFOR indices for fossil, nuclear and hydroelectric units, used for this study, are contained in Table A.3. They were either provided by market participants (and reflect a combination of past experience and expected future experience) or they are representative values chosen from NERC GADS data.

Table A.3 Ontario Projected Equivalent Forced Outage Rates

Fuel Type	EFOR (%)
Nuclear	2 - 8
Coal	5 - 45
Oil/Gas	5 - 50
Hydroelectric	<3
Other	9

1.2.3 Purchase and Sale Representation

No purchase or sale contracts were identified to the IMO for the five-year period, therefore none were considered for this assessment.

1.2.4 Retirements

An amount of 1,148 MW of generating capacity was assumed to retire in April 2005, as indicated by the facility owner.

1.3 REPRESENTATION OF INTERCONNECTED SYSTEMS

There are five systems with which the Ontario system is interconnected: Manitoba, Minnesota, Michigan, New York and Quebec. The five interconnected systems that can provide assistance to the Ontario system were modeled as external to the Ontario pool. Neighbouring systems treated as external areas with constant hourly loads of 1 MW. In each of these external areas a dummy generator was modeled, with a variable capacity up to the amounts expected to be offered into the Ontario market. The expected capacity values were based on past operational experience and load and capacity reports issued by the respective system operators, subject to the limitations of the transmission interconnections outlined in Table A.4. Limits apply year-round except where seasonal ratings are indicated.

Table A.4 Ontario Interconnection Limits

Interconnection	Limit - Flows Out of Ontario MW	Limit - Flows Into Ontario MW
Manitoba	275	324
Minnesota	140	90
New York St. Lawrence	400	400
Quebec North – Summer	95	65
Quebec South (East and Ottawa) - Summer	740	1,385
New York Niagara (60 Hz and 25 Hz) – Summer	1,800	1,300
Michigan – Summer	2,100	1,700
Quebec North – Winter	110	84
Quebec South (East and Ottawa) - Winter	760	1,385
New York Niagara (60 Hz and 25 Hz) – Winter	2,000	1,500
Michigan – Winter	2,200	1,700

An analysis of historical power flows on Ontario's interconnections for the five years prior to market opening in 2002 shows that outside of summer peak demand periods up to 1,800 MW of external generation supplied Ontario demand. From the same analysis, up to 1,400 MW external generation supplied Ontario demand during summer peak months in recent years prior to 2002.

During Ontario's summer peak demand periods of July and August expected requirements for imports are greatest: imports are still expected to be available despite the fact that many neighbouring systems are often experiencing their peak demand. This is mainly due to the non-coincidence of the daily peak hours between Ontario and its neighbours and the availability of spare capacity from systems that are not summer peaking.

The actual hourly import levels experienced from market opening in May 2002 up to February 11, 2003 indicate an average import level of 1,088 MW for all hours. During the 1,440 hours when Ontario demand exceeded 20,000 MW the average import level was 1,622 MW. During the 225 hours when Ontario demand exceeded 23,000 MW the average import level was 2,371 MW, and occasionally reached the Ontario coincident import capability (approximately 4,000 MW).

The NPCC CP-5 study entitled "Review of Interconnection Assistance Reliability Benefits" published in May 1999, provided an assessment that over 2,500 MW of interconnection assistance is reasonably available to the Ontario system and recommended that Ontario increase its tie benefit assumptions. A degree of modeling bias in that study may have overstated the Ontario tie benefit; new studies being conducted this year are expected to provide updated guidance for assumptions of tie benefit for Ontario and all other NPCC areas.

Future levels of imports into Ontario will vary depending on several factors, including the availability and willingness of resources in external jurisdictions to supply the Ontario market, and the availability of required transmission capacity. However, for the purposes of this study the total interconnection assistance assumed available to Ontario over the five-year period was set at 1,500 MW.

1.4 MODELING OF LIMITED ENERGY RESOURCES

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

1.5 MODELING OF DEMAND-SIDE MANAGEMENT

Peak demand values include loads that may be dispatched off during high price periods, loads that may simply reduce in response to high prices, and loads that may otherwise be reduced in the case of a shortfall in reserves. For the purposes of resource adequacy assessments, the IMO assumes that 300 MW of price-responsive demand is available, based on operational experience. This amount was modeled in MARS as part of the emergency operating procedures (EOP).

1.6 MODELING ALL RESOURCES

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

1.7 OTHER ASSUMPTIONS

1.7.1 Internal Transmission Limitations

The Ontario IMO-controlled grid consists of a robust southern grid and a sparse northern grid. It has been modeled as a pool composed of ten zones. Figure A.1 provides a pictorial representation of Ontario's ten zones. All transmission interfaces between the ten zones within the Ontario pool were modeled as they are defined in IMO System Control Orders (SCO). No random transmission outages were modeled on the interfaces. The transfer limits were specified for each direction of the interface (positive and negative) and were changed seasonally if necessary. The amount of assistance that deficient zones were permitted to receive from zones with excess resources was limited by the transfer limits on the interfaces, as shown in Table A.5. Limits apply year-round except where seasonal ratings are indicated.

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

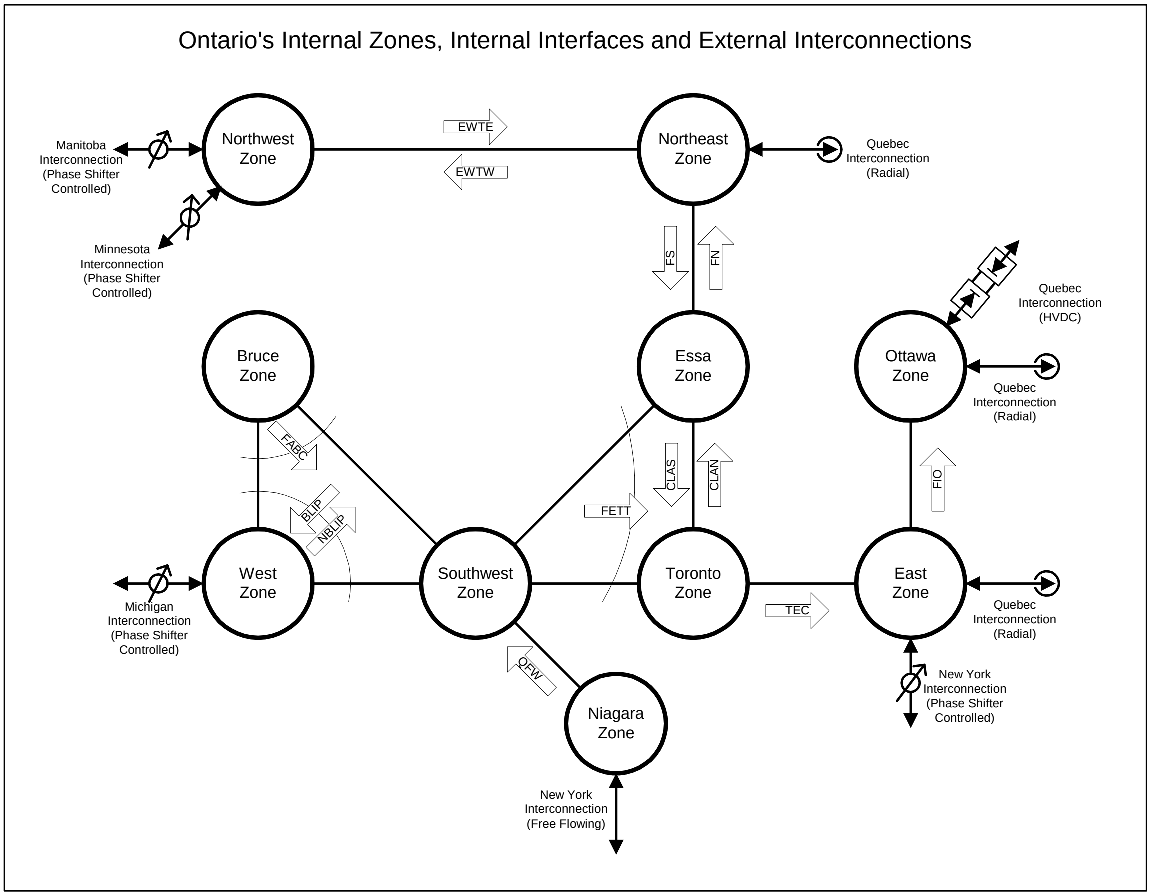

Table A.5 Ontario Internal Interface Base Limits

Interface	Operating Security Limits (MW)
BLIP	3,500
NBLIP	1,500
QFW	1,750 Summer, 1,950 Winter
FABC	5,300
FETT	5,100 Summer, 5,700 Winter
CLAN	2,000
CLAS	1,000
FIO	1,900
FN	1,900
FS	1,400
EWTE	325
EWTW	350

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