IESO 2006 Comprehensive Review of Ontario Resource Adequacy

for the period 2007 to 2011

October 30, 2006

IESO-REP-0347v1.2

Approved by the RCC November 28, 2006

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1.0 EXECUTIVE SUMMARY

1.1 Major Findings

The Independent Electricity System Operator (IESO) 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 supersedes the review conducted in 2003. The guidelines for the review are specified in the NPCC Document B-8 entitled, "*Guidelines for Area Review of Resource Adequacy*" (Revised: November 29, 2005).

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

Since the last comprehensive review in 2003, about 3,500 MW of incremental generation capacity has been added in Ontario, and 1,150 MW of capacity has been retired. Capacity additions include about 1,900 MW of additional nuclear capacity and about 750 MW of additional gas-fired capacity. In addition, future generating resource capacity additions of 9,815 MW are under construction or planned to come into service during the study period 2007 to 2011. At the present time, IESO is working with Ontario Power Authority (OPA) to ensure reliability in Ontario while reducing coal-fired emissions. The Ontario government has a policy to shut down the coal plants once replacement capacity is available. The plants will remain in operation as required to maintain reliability. It is assumed that coal-fired generation will continue to be available during the study timeframe of 2007 to 2011.

This year's comprehensive review demonstrates that Ontario is expected to meet the NPCC overall resource adequacy criterion. New generation that is expected to come into service will increase the reliability of the Ontario power system.

1.2 Major Assumptions and Results

This review covers the period from 2007 to 2011 inclusive. Major assumptions are summarized in Table 1.1 below:

Table 1.1 Major Assumptions

Assumption	Description
Adequacy Criterion	NPCC Loss Of Load Expectation (LOLE) requirement of not more than 0.1 days/year.
Reliability Model	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	9,815 MW by the end of 2011.
Generating Capacity Retirements	None
Internal and Interconnection Transmission Constraints	Based on IESO normal system operating security limits.
Tie Benefits	initial assumption 0 MW For some years, increase from 0 MW (tie capability = 4,000 MW)
Emergency Operating Procedures	Initial runs had no EOPs modeled Additional runs were modeled with EOPs for calendar years when LOLE of 0.1 not attained without EOPs
Unit Availability	Outage plans modeled: Generic planned outages are 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.
Price responsive Demand	0 MW
Conservation and Demand Management (CDM)	Up to 1351 MW by 2011

MARS calculations were performed with up to five different study conditions. In the first set of MARS runs, the calculations were performed with the assumptions listed above, without the use of any emergency operating procedures, and a with a more conservative level of available resources. The second set of MARS runs were performed with the assumptions listed above, without the use of any emergency operating procedures, and with all planned resources assumed to be available. For the calendar years when the resultant annual LOLE exceeded criterion, a third MARS run was performed, with emergency operating procedures modeled. In the remaining calendar year of 2007 when the LOLE still exceeded criterion, a fourth MARS run was performed with additional capacity modeled as interconnection assistance. The intent of this run was to find that amount of additional resources, above the assumed resource level assumptions, that would be required to have Ontario meet the LOLE criterion. The amount of additional resources required, depends on the amount of resources assumed to come into service on the forecast date. MARS results for the median and high demand growth scenarios are presented in Tables 1.2 and 1.3.

Table 1.2 Annual LOLE Values, Median Demand Forecast

Scenario	EOPs	Additional Resources (MW)	LOLE [days/year]				
			2007	2008	2009	2010	2011
M1	no	0	6.595	0.641	0.022	0.012	0.006
M2	no	0	2.942	0.173	0.007	0.007	0.006
M3	yes	0	1.173	0.049	-	-	-
M4	yes	1050	0.099	-	-	-	-
M5	yes	565	0.099	-	-	-	-

The initial set of runs, under median demand growth forecast, shows that Ontario would meet the LOLE criterion for all years of the study period. The five sets of MARS runs indicates the level of resources necessary to achieve the LOLE criterion of 0.1 days/year. For the calendar year 2007 additional resources up to 1050 MW are required, as shown in scenario M4. However, if all planned resources are assumed to come into service, the additional resources required would be about 565 MW, as shown in scenario M5. These additional resources are expected to be available to meet Ontario demand, and could include some combination of additional price-sensitive demand, additional demand management and/or imports into Ontario. For the 2008 calendar year, Ontario would meet the LOLE criterion with some use of emergency operating procedures (EOPs). For the calendar years 2009 to 2011, the LOLE criterion would be met without any additional resources, and without the need to implement any emergency operating procedures.

Table 1.3 Annual LOLE Values, High Demand Forecast

Scenario	EOPs	Additional Resources (MW)	LOLE [days/year]				
			2007	2008	2009	2010	2011
H1	no	0	6.759	1.163	0.048	0.049	0.033
H2	no	0	3.577	0.312	0.010	0.030	0.033
H3	yes	0	1.484	0.090	-	-	-
H4	yes	1200	0.091	-	-	-	-
H5	yes	715	0.099	-	-	-	-

Under the high demand forecast assumption, Ontario would meet the LOLE criterion for all years of the study period. The five sets of MARS runs indicates what level of resources are necessary to achieve the LOLE criterion of 0.1 days/year. For the calendar year 2007 additional resources up to 1200 MW are required, as shown in scenario H4.

However, if all planned resources are assumed to come into service, the additional resources required would be about 715 MW, as shown in scenario H5. The additional resources are expected to be available to meet Ontario demand, and could include some combination of additional price-sensitive demand, additional demand management and/or imports into Ontario. For the 2008 calendar year, Ontario would meet the LOLE criterion with some use of emergency operating procedures. For the calendar years 2009 to 2011, the LOLE criterion would be met without additional resources, and without the need to implement any emergency operating procedures.

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3.0 INTRODUCTION

This report is the comprehensive area review of resource adequacy for Ontario, prepared by the Independent Electricity System Operator (IESO) 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 November 29, 2005).

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

The information presented in this report covers the period from 2007 to 2011.

3.1 Reference to Most Recent NPCC Comprehensive Review

The previous Ontario comprehensive review was submitted by the Independent Market Operator (IMO) and was approved by the Reliability Coordinating Committee on November 4, 2003. Comparisons between this review and the November 4, 2003, "IMO Year 2003 Triennial Review of Ontario Resource Adequacy" are contained in this report. (The IESO was previously named the IMO.)

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 seasonal peak demand forecasts for both the 2003 and 2006 reviews. The 2006 peak values are based on Seasonal normal weather. The peaks are presented for both the median and high growth scenarios. Although point forecasts are presented for both the median and high growth scenarios each scenario has an associated distribution of demand outcomes recognizing the variability of weather. This forecast distribution of demand will indicate that if more extreme weather is experienced, the demand realized may be considerably more than the normal weather peak indicated. For example, for the forecast for the summer of 2007, the normal weather peak of 24,768 MW is expected under normal weather. However, if extreme weather is experienced, a peak demand of about 27,500 MW would be expected. This is consistent with the experience of the summer of 2006, when the actual peak demand experienced was 27,005 MW. This demand level was attained during some challenging weather conditions, although the conditions were not the most extreme that Ontario has experienced. 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 31 years of record. The 2003 forecast values were based on a Weekly normal weather which would yield lower peaks than a forecast based on Seasonal normal weather. In addition to the change in the underlying weather assumptions, differences between the two forecasts arise for two main reasons. First, the underlying economic projections between the two forecasts have changed over the past two years. Second, the inclusion of actual data has influenced the relationships between economics, weather and demand. In particular, the weather during the summer of 2005 and structural shifts in the economy over the past two years have changed both the demand forecasting models and the results. Therefore, both the starting points and the growth rates have changed.

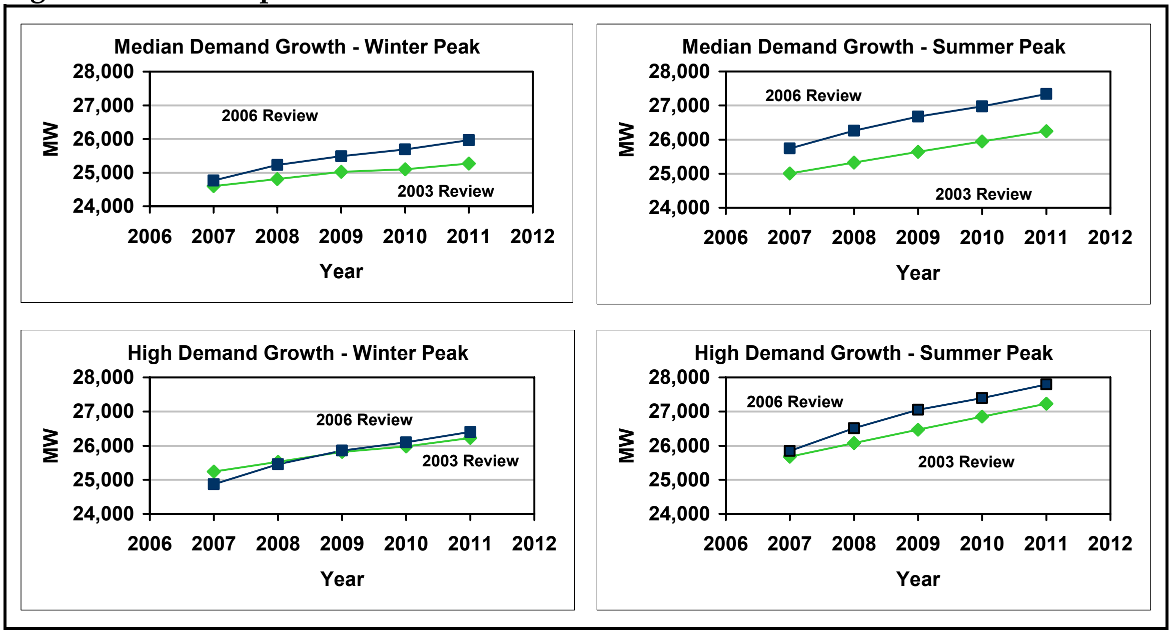
Table 3.1 Comparison of Demand Forecasts: Normal Weather Winter Peak

Year	Normal Weather Winter Peak			
	Median Demand Growth		High Demand Growth	
	2003 Review	2006 Review	2003 Review	2006 Review
2007	24,603	24,768	25,240	24,867
2008	24,808	25,226	25,523	25,454
2009	25,024	25,486	25,818	25,851
2010	25,101	25,690	25,973	26,100
2011	25,273	25,960	26,223	26,404
Average Growth Rate	0.67%	1.18%	0.96%	1.51%

Table 3.2 Comparison of Demand Forecasts: Normal Weather Summer Peak

Year	Normal Weather Summer Peak			
	Median Demand Growth		High Demand Growth	
	2003 Review	2006 Review	2003 Review	2006 Review
2007	25,005	25,741	25,672	25,849
2008	25,326	26,263	26,072	26,508
2009	25,641	26,675	26,466	27,055
2010	25,945	26,973	26,850	27,397
2011	26,247	27,337	27,230	27,794
Average Growth Rate	1.22%	1.51%	1.48%	1.83%

Figure 3.1 Comparison of Demand Forecasts



3.2.2 Resources Forecast

Table 3.3 indicates the resources forecast to be available to the Ontario system at the time of the seasonal peaks assumed for this review and for the 2003 review. The IESO's current forecast of available resources is generally higher than the 2003 forecast, due to additional gas-fired generating capacity which was not anticipated in 2003.

Table 3.3 Comparison of Available Resource Forecasts

Year	Winter Peak			Summer Peak		
	2003 Review	2006 Review	Difference	2003 Review	2006 Review	Difference
2007	30,156	27,656	-2,500	29,731	28,907	-824
2008	29,894	29,113	-781	29,602	29,894	292
2009	29,398	31,451	2,053	29,051	32,309	3,258
2010	29,401	31,779	2,378	29,054	33,585	4,531
2011	29,401	36,649	7,248	29,057	37,099	8,042

3.2.3 Resource Adequacy Assessment Criterion

For both the 2003 and the current review, the assessment criterion described in Section 4.1 was used, which is the same as the NPCC resource adequacy criterion.

- End of Section -

4.0 RESOURCE ADEQUACY ASSESSMENT CRITERION

4.1 Statement of Resource Adequacy Assessment Criterion

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

> "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."

4.2 Statement of How the Criterion is Applied

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

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 considering submissions by generator owners, actual historic outage observations and more generalized outage factors.

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

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

- disregard 30-minute operating reserve requirement;
- implement Emergency Load Reduction Program (ELRP);
- 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 (EDRP);

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 Procedure Assumptions

EOP Action	Load Relief [% of demand or MW value)
Public Appeals	1%
Stretch	188 MW
No 30m OR	473 MW
ELRP	56 MW
Voltage Reductions	2.80%
No 10m OR	895 MW
EDRP	115 MW

4.3 Resource Requirements to Meet Criterion

For the purposes of this study, the adequacy of Ontario's existing and planned resources is assessed through calculation of the annual LOLE and compared with the 0.1 days/year target prescribed by the NPCC resource adequacy criterion. Initial studies are performed without any additional resources above the identified assumptions. For the calendar year of 2007, additional resources, of up to 1200 MW may be required to meet criterion.

4.4 Comparison of IESO and NPCC Criteria

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

4.5 Resource Adequacy Studies Done Since the 2003 Review

Adequacy assessments produced by the IESO (or IMO) since the last Area review include numerous 18-Month Outlooks published on a quarterly basis, two 10-Year Outlooks published in 2004 and 2005, and the Ontario Reliability Outlook published in February and June 2006. All of these reports, available on the IESO web site (www.IESO.ca), were submitted to the Minister of Energy and the Ontario Energy Board to meet the requirements of the Ontario Market Rules.

- End of Section -

5.0 RESOURCE ADEQUACY ASSESSMENT

5.1 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 LOLE Values, Median Demand Forecast

Table 5.1 shows that under the median demand growth assumptions Ontario will have adequate resources to meet the NPCC criterion through 2011. The five sets of MARS runs indicates the level of resources necessary to achieve the LOLE criterion of 0.1 days/year. Scenario M4 and Scenario M5 differ in the amount of planned resources that are assumed to come into service. For the calendar year of 2007 additional resources up to 1050 MW are required, as shown in scenario M4. However, if all planned resources are assumed to come into service, the additional resources required would be about 565 MW, as shown in scenario M5. These additional resources are expected to be available to meet Ontario demand through some combination of additional price-sensitive demand, additional demand management and/or imports into Ontario. For the 2008 calendar year, Ontario would meet the LOLE criterion with some reliance on emergency operating procedures (EOPs). For the calendar years 2009 to 2011, the LOLE criterion would be met without any additional resources, and without the need to implement any emergency operating procedures.

Table 5.1 Annual LOLE Values, Median Demand Forecast

Scenario	EOPs	Additional Resources (MW)	LOLE [days/year]				
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M1	no	0	6.595	0.641	0.022	0.012	0.006
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M4	yes	1050	0.099	-	-	-	-
M5	yes	565	0.099	-	-	-	-

5.2 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 LOLE Values, High Demand Forecast

Under the high demand forecast assumption, Ontario would meet the LOLE criterion for all years of the study period. The five sets of MARS runs indicates what level of resources are necessary to achieve the LOLE criterion of 0.1 days/year. For the calendar year 2007 additional resources up to 1200 MW are required, as shown in scenario H4. However, if all planned resources are assumed to come into service, the additional resources required would be about 715 MW, as shown in scenario H5. The additional resources are expected to be available to meet Ontario demand, and could include some combination of additional price-sensitive demand, additional demand management and/or imports into Ontario. For the 2008 calendar year, Ontario would meet the LOLE criterion with some use of emergency operating procedures. For the calendar years 2009 to 2011, the LOLE criterion would be met without additional resources, and without the need to implement any emergency operating procedures.

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H3	yes	0	1.484	0.090	-	-	-
H4	yes	1200	0.091	-	-	-	-
H5	yes	715	0.099	-	-	-	-

5.3 Contingency Mechanisms for Managing Demand and Resource Uncertainties

At least twice a year, the IESO prepares an Ontario Reliability Outlook (ORO) for the IESO Board of Directors, the Minister of Energy and the Ontario Energy Board, as well as market participants. The ORO provides 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 IESO includes projects which are under construction, or that are planned to be in-service.

Since the Ontario market opened in 2002, the Ontario market incentives proved insufficient to motivate construction of additional generators or development of comparable demand response programs, and several additional steps have and will be taken to ensure Ontario's future demand - resource balance.

Requests for Proposals for additional generation and demand response programs were initiated by the Ontario Government and continue to be developed and managed by the Ontario Power Authority. In part, the need for additional requests for proposals is driven by reliability assessments performed by IESO, including this assessment.

Every quarter, looking from one month in the future out 18 months, the IESO assesses the integrated generator and transmission outage plans of market participants. Periods where planned outages result in inadequate resource levels are identified to generators and transmitters. If market participants fail to proactively reschedule planned outages to mitigate concerns, the IESO 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 range up to 5,400 MW over the 18 month study period.

Since market opening, there have been several different types of emergency operating procedures developed including an Emergency Demand Response Program (EDRP), Transitional Demand Response Program (TDRP), and an Emergency Load Reduction Program (ELRP). The contribution that these programs are expected to make in meeting the demand supply balance have been included in the MARS model, for calendar years when the resource adequacy criterion is not met.

The need to consider imports into Ontario to achieve the resource adequacy criterion varies depending on the calendar year under consideration and the demand assumptions. The coincident interconnection import capability is normally about 4,000 MW. Data collected since market opening reveals the average imports that have been attracted into Ontario with market mechanisms, and NPCC studies have been conducted to indicate an estimate of the annual tie benefits that can be expected. As indicated later in this report, both the historic import data and the NPCC tie benefit studies support the conclusion that the additional resources required to meet criterion in 2007 could be achieved solely through reliance on imports.

- End of Section -

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 Ontario Government intends to decrease the amount of emissions from coal-fired generation, and much of the new replacement energy is expected to be gas-fired. There is also expected to be a significant increase in the amount of wind powered generation in Ontario. Working groups have been established to consider the reliability impact of these changes. GE Energy, partnered with AWS Truewind, has signed a contract with the Ontario Power Authority, IESO and the Canadian Wind Energy Association to study the impact of wind power on the Ontario electricity system.

The recently completed study will be used to assist the development of the Ontario Power Authority's Integrated Power System Plan (IPSP).

The IPSP will cover a 20-year time frame and will establish direction, strategy, and an action plan for the development and implementation of renewable and other forms of generation and transmission to meet consumer energy supply needs. The ultimate goal of the wind study is to determine the maximum amount of wind power that could be added to the Ontario bulk power system with minimal impact on system operation.

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 coal unit retirements, additional equipment to reduce emissions or lower utilization factors for some generating units. The Ontario Government, the IESO and the OPA will be considering what coal emission reduction steps are considered appropriate, while maintaining the reliability of the power system.

Table 6.1 and Figure 6.1 show the net installed capacity mix at the time of the summer peak for each year in the study period.

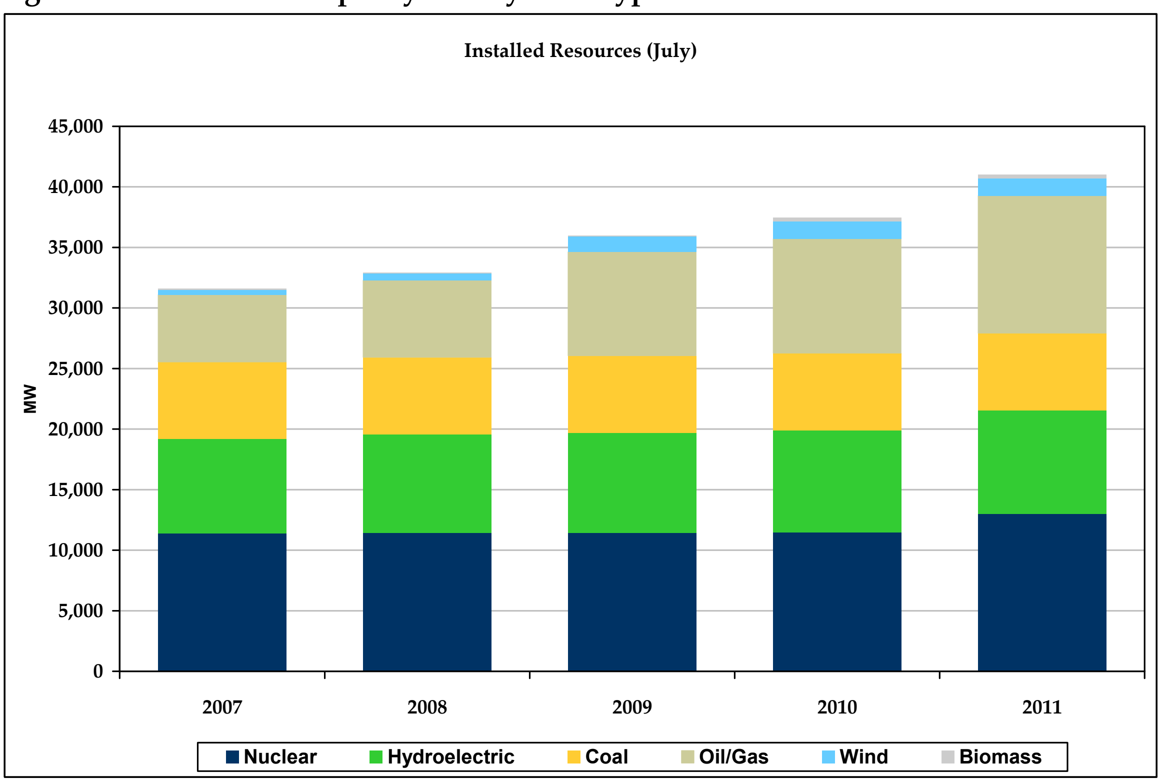
Table 6.1 Ontario Capacity Mix by Fuel Type

July Installed Resources					
Fuel Type	**2007**	**2008**	**2009**	**2010**	**2011**
Nuclear	11,397	11,397	11,397	11,397	12,998
Coal	6,434	6,434	6,434	6,434	6,434
Oil/Gas	5,588	6,408	8,618	9,483	11,383
Hydroelectric	7,768	8,148	8,274	8,431	8,561
Wind	405	571	1,261	1,461	1,461
Biomass	71	71	71	301	301
Total	31,663	33,029	36,054	37,506	41,137

Table 6.2 Ontario Capacity Mix by Fuel Type (%)

Fuel Type \ Year	2007	2008	2009	2010	2011
Nuclear (%)	36	35	32	30	32
Coal (%)	20	19	18	17	16
Oil/Gas (%)	18	19	24	25	28
Hydroelectric (%)	25	25	23	22	21
Wind (%)	1	2	3	4	4
Biomass (%)	0	0	0	1	1

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 next few years, about 1,300 MW of new wind-powered generation is expected to be in-service in Ontario. Although the wind generation capacity contribution must be substantially discounted from the nameplate value, wind energy can successfully reduce the utilization of other potentially energy-limited resources.

The IESO actively encourages diversity in supply options by identifying future capacity needs and engaging in dialogue with the Ontario Government, Ontario Power Authority, market participants and other stakeholders. As a competitive alternative to new and existing generation, the IESO promotes a balanced pursuit of supply diversity and demand management options in its Outlooks. In December 2005, the Ontario Power Authority (OPA) published the Supply Mix Advice and Recommendations Report to present recommendations to the Minister of Energy on options for the future development of Ontario's electricity system. It responded to a request from the Minister on May 2, 2005 for advice on the appropriate mix of electricity supply sources to satisfy the expected demand in Ontario, taking into account conservation targets and new sources of renewable energy out to 2025. The Ontario Power Authority considered the IESO recommendations in the report.

The OPA is completing Ontario's first Integrated Power System Plan (IPSP) in many years. With this step, Ontario is approaching a major milestone in the re-development of the provincial electricity system. Looking ahead 20 years, the IPSP will identify the conservation, generation and transmission investments that are needed to ensure a reliable, sustainable power supply. This plan is expected to be submitted to the Ontario Energy Board in March of 2007.

The IESO will continue to monitor the plans for Ontario future fuel mix and consider the reliability impacts in the Ontario Reliability Outlooks and 18-Month Outlooks conducted several times each year.

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APPENDIX

APPENDIX A - DESCRIPTION OF RESOURCE RELIABILITY MODEL

For the purposes of this study, the IESO used the Multi-Area Reliability Simulation (MARS) program. The 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 IESO uses a multivariate econometric model to forecast energy and peak demand on the IESO-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 median weather observations based on 31 years of historical data. A consensus of publicly available, provincial forecasts are used to determine the economic drivers in the forecast for the initial years of the study (2007-2008). Beyond 2008, population projections are used to proxy the economic drivers needed for the forecast. The forecast used for this study was based on load, weather and economic data through to the end of March 2006. 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 1.2% over the 2007-2011 time frame. The high growth scenario had the economic factors growing at a much stronger 2.1% per annum over the same period. Compared to the median growth scenario, the high growth scenario has 535,000 more people employed and just over 100,000 more houses in 2011.

1.1.2 Load Forecast Uncertainty

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

1.1.3 Demand -Side Management

In the demand forecast, the peak demand values include loads that have been contracted to provide demand response. MARS runs were completed which modeled the conservation and demand management estimates that have been proposed for Ontario. The annual values assumed for the conservation demand management are shown in the table below.

Table A.1 Conservation and Demand Management Assumptions

Year	DSM Value coincident with annual peak [MW]
2007	485
2008	729
2009	976
2010	1061
2011	1351

1.2 RESOURCE REPRESENTATION

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

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

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

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

1.2.1 Unit Ratings

1.2.1.1 Definitions and Values

The aggregated net installed capacity values for all generating units expected to be participating in the IESO markets, as of July 2007, are shown in Table A.2.

Table A.2 Net Installed Capacity as of July 2007

Fuel Type	Total Capacity [MW]
Nuclear	11,397
Coal	6,434
Oil/Gas	5,588
Hydroelectric	7,768
Wind	405
Biomass	71
Total	31,663

For resources other than hydroelectric, the summer seasonal (July) output capabilities, as submitted by market participants, or estimated by IESO were input to MARS. These capabilities take into account any output deratings given by equipment or ambient limitations, and environmental restrictions.

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

1.2.1.2 Procedure for Verifying Ratings

Market participants submit to the IESO, seasonal ratings. In accordance with the NPCC Compliance Monitoring Program and specifically, according to NPCC NRAP Template C7 Verification of Generator Unit Capability (NPCC Document B-9: Guide for Rating Generating Capability), the IESO assessment concluded that the Independent Electricity System Operator as Ontario Transmission Operator and Reliability Coordinator is in full compliance with the criterion.

For this review, the IESO used ratings submitted by market participants for resources other than hydroelectric. For hydroelectric facilities the contributions were based on median measured contributions to meet peak Ontario demand.

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. Where available, these were based on unit specific data supplied by market participants. Historic information and forecast future performance are also considered in the EFOR modeled.

Planned maintenance was modeled on a unit basis. Representative outage plans were used.

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 IESO for its routine Outlooks. Actual outage history is obtained from the IESO's Integrated Outage Management System. For sensitivity studies that consider new gas-fired generation, studies from other jurisdictions provided a reasonable range of possible EFORs for new gas-fired generators.

1.2.2.3 Maturity Considerations and In-Service Date Uncertainty

MARS runs shown assumed new gas-fired generators have a 9% EFOR. There is uncertainty in the level of new unit performance. Sensitivity runs were completed assuming that for the first 12 months of new gas-fired generation, EFOR is 14.5%, for the second 12 months the EFOR is 8% and after the 24 months, the EFOR is 4.5%.

Results of the sensitivity MARS runs indicate that the need for additional resources would increase by about 200 MW in 2007, if the new gas-fired generation experiences the higher EFOR values, as shown in the table below.

Table A.3 Immaturity EFOR Values

Time after In-service Date	EFOR [%]
First 12 months	14.50%
Second 12 months	8.0%
After 24 months	4.5%

There is some uncertainty in the date that new generating resources will come into service, and the extent to which demand side resources will come into service on schedule. The MARS runs include resource reductions to account for these uncertainties. The assumed resource levels could be experienced if no demand management comes into service, or some other combination of demand management and/or generating resources do not come into service during the study 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 the table below. 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.4 Ontario Projected Equivalent Forced Outage Rates

Fuel Type	Weighted Average EFOR	Range of EFOR
Biomass	9%	9%
Coal	16%	5 - 25 %
Gas	9%	9%
Nuclear	5%	3 - 7 %
Oil	11%	5 - 50 %

1.2.3 Purchase and Sale Representation

No firm purchase or firm sale contracts are identified for the five-year study period. Experience has shown that the Ontario market typically attracts economic imports into Ontario. For calendar years when Ontario would not meet the target resource adequacy criterion without any additional resources, up to 1200 MW of imports from ECAR were assumed to be deliverable to Ontario, in order to meet the target LOLE.

1.2.4 Retirements

There are no retirements assumed for the duration of the study period.

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 are 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 varied, depending on Ontario needs, but were always 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.5 Ontario Interconnection Limits

Interconnection	Limit - Flows Out of Ontario MW	Limit - Flows Into Ontario MW
Manitoba – Summer	263	331
Manitoba – Winter	275	343
Minnesota	140	90
Quebec North (Northeast) – Summer	95	65
Quebec North (Northeast)– Winter	110	84
Quebec South (Ottawa) – Summer	147	748
Quebec South (Ottawa) – Winter	167	748
Quebec South (East) – Summer	420	800
Quebec South (East) – Winter	470	800
New York St. Lawrence	400	400
New York Niagara (60 Hz and 25 Hz) – Summer	1,300	1,300
New York Niagara (60 Hz and 25 Hz) – Winter	1,950	1,650
Michigan – Summer	1,950	1,550
Michigan – Winter	2,200	1,750

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 September, 2006 indicate an average import level of 1,087 MW for all hours. During the 7,004 hours when Ontario demand exceeded 20,000 MW the average import level was 1,404 MW. During the 837 hours when Ontario demand exceeded 23,000 MW the average import level was 2,082 MW, and occasionally reached the Ontario coincident import capability (approximately 4,000 MW).

The NPCC CP-8 study entitled "Review of Interconnection Assistance Reliability Benefits" published in June 2004, provided an assessment that between 3,150 and 4,050 MW of interconnection assistance is reasonably available to the Ontario system.

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 required for Ontario over the five-year period was not more than 1200 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. 4 MODELING OF WIND GENERATION

Wind generation was modeled as a Type 1 Energy-Limited Resource. The values were based on data obtained from a joint wind study conducted by General Electric and AWS Truewind to focus on wind generation in Ontario. The wind production estimates modeled in MARS were based on the cumulative probability density function for all hours in July. The average capacity value for all hours in July was 17%. This value is identical to the summer capacity contribution estimated by GE/AWS for demands in excess of 90% of annual peak.

1.6 MODELING OF DEMAND RESPONSE

The peak demand values include loads that have been contracted to provide demand response. For the resource assessments, the MARS runs were modeled with and without dependable demand response capacity. It is not certain how often consumers would tolerate calls for demand response, and that Ontario should plan to acquire other resources rather than rely on demand response for sustained periods. MARS runs were completed with conservation and demand management quantities up to 1350 MW by 2011. The table of demand response assumptions is shown in Table A.1.

1.7 MODELING ALL RESOURCES

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

1.8 OTHER ASSUMPTIONS

1.8.1 Internal Transmission Limitations

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

Enhancements to the transmission system to carry power from the Bruce peninsula are required to fully accommodate future increases to generation capacity in the Bruce area. The OPA agreement with Bruce Power to refurbish and return to service two Bruce A units, combined with the contracted wind power in the Bruce area, will result in additional capacity in the area.

The existing transmission system is much less capable of accommodating additional supply at Bruce than it was in the past. A number of factors associated with the dynamic and changing nature of the system have included:

- High load growth in the GTA, particularly in summer
- The shutdown of generation in the GTA (Pickering A and Lakeview)
- The addition of generation in southwest Ontario and increase in imports from Michigan

In recognizing these factors, 500 kV transmission reinforcement will be needed to reliably deliver the full capacity of new generation.

After factoring in long-term maintenance on other units at Bruce, the full eight-unit capability is expected to be available by late 2011. Work must start on new transmission facilities as soon as possible. Given the typical approvals time and expected construction lead times, this project is at risk of being late.

Stopgap measures, such as the use of Special Protection Systems to automatically disconnect generation, and the installation of series compensation on 500 kV circuits in southern Ontario, are being considered for use in advance of the line being available.

There may be several other areas of Ontario, where anticipated transmission enhancements are planned, and where transmission limits could be improved. However, detailed studies have not been completed to produce any revised transfer limits. This review has shown that Ontario is compliant with NPCC criterion without any increase to the internal transmission limits within Ontario. To the extent that improvements to transmission limits may be realized, this will only lower the LOLE values.

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

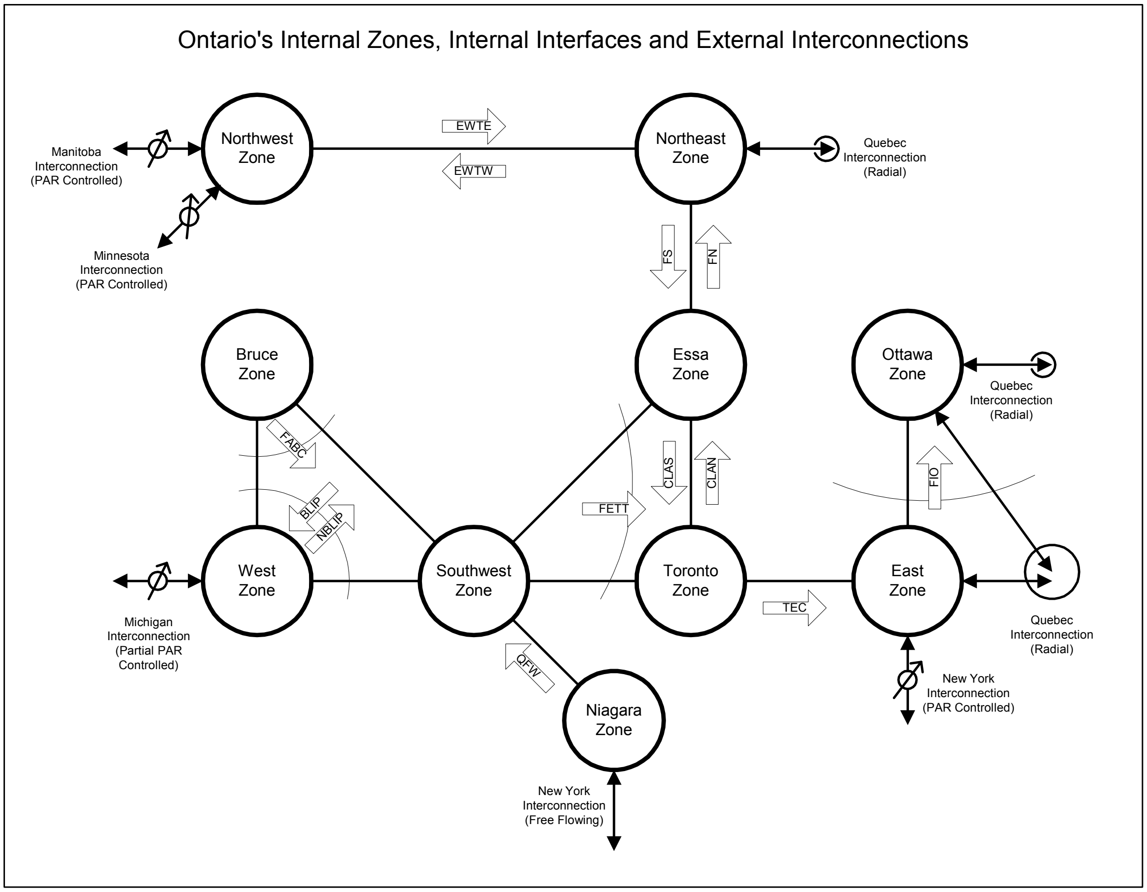

Table A.5 Ontario Internal Interface Base Limits

Interface	Operating Security Limits (MW)
BLIP	3,500
NBLIP	1,500
QFW	1,750 Summer, 1,950 Winter
FABC	4,050-4,450 with four Bruce B units in-service 4,440-4,950 with five Bruce units in-service 4,500-5,300 with six 500 kV Bruce units in-service
FETT	5,700
CLAN	2,000
CLAS	1,000
FIO	1,900
FN	1,900
FS	1,400
EWTE	325
EWTW	350

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