

Independent Electricity Market Operator

10-Year Outlook:

***An Assessment of the Adequacy of Generation and
Transmission Facilities to Meet Future Electricity Needs in
Ontario***

From January 2002 to December 2011

July 11, 2001



Executive Summary

The IMO has a responsibility to forecast the demand for electricity in the province and to assess whether the existing and proposed generation and transmission facilities are adequate to meet Ontario's needs. This document looks at the ten-year period from 2002 to 2011.

Based on existing and proposed facilities, Ontario has a reliable supply of electricity for the next ten-years under a wide-variety of conditions. Opportunities also exist for additional enhancements to improve the efficiency of the Ontario electricity market.

The assessments in this report were made based on a number of key planning assumptions. Assuming a median growth scenario, the energy demand is forecast to grow at an average rate of 1.2% per year - from 152 terawatt-hours (TWh) in 2002 to 168 TWh at the end of the study period. The median forecast projects peak demand to rise from 23,700 MW to 26,000 MW at the end of the period. A low demand growth scenario, with an average growth rate of 0.8% and high demand growth scenario, with an average growth rate of 1.7%, were also studied.

For purposes of the base case assessments, generator unavailability due to planned and forced outages was modelled, and support from neighbouring systems was assumed to be limited to the magnitude of existing firm purchase contracts that have been identified to the IMO. These firm purchase contracts extend to October 2003.

Pickering A units are assumed to return to service beginning in 2002 in accordance with a schedule provided by Ontario Power Generation Inc. The base case scenario did not account for additional capacity that may be available from a number of the proposed additional generation projects that are undergoing assessment by the IMO. In addition, 300 MW of demand was assumed to be dispatchable or responsive to market prices. Although announcements have been recently made about the intention of Bruce Power to return to service two of the Bruce A units, the capacity of installed generation resources used for the present study does not include Bruce A units.

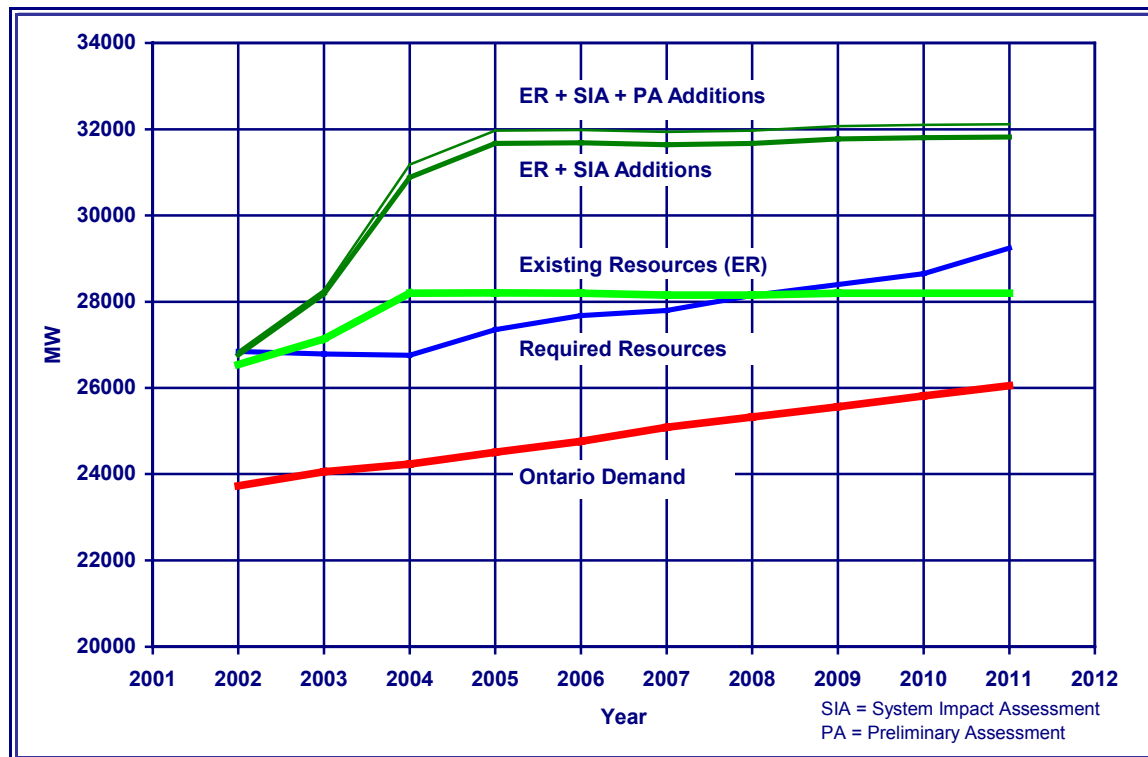
The Northeast Power Coordinating Council (NPCC) reliability standard, based on a Loss of Load Expectation (LOLE) of not more than once in 10 years, is forecast to be met throughout the study period. The resources that are assumed to be available to supply Ontario's forecast electricity demands for the period from 2002 to 2011 are expected to be adequate to meet the specified reserve margin requirements with only a few exceptions. For 2002, suitable alternate resource supply options are assessed to be available in the operating timeframe to manage these periods. During the mid to latter years of the study period, the construction of 2,000 to 3,000 MW of the 6,000 MW proposed resource additions, or the development of an equivalent amount of price responsive demand, will be sufficient to enable the NPCC reliability standard to be met. Figure 1 shows graphically a summary of the winter peak outlook assuming a median demand growth, and showing various levels of resource availability.

In addition to considering the adequacy of existing generation, this Outlook estimates the collective impact of all proposed new generation projects, as identified to the IMO through the Connection Assessment and Approval process. If all generation proposals are built and operated, the amount of generation that is exclusively gas fuelled would comprise about 21% of the

installed capacity within Ontario by 2005. Another 6% of the installed capacity would be dual-fuelled with gas. The IMO has not studied the adequacy of gas supplies, or the adequacy of the gas supply infrastructure in Ontario. The IMO supports the initiation of a multi-party study in the near future. Many other jurisdictions are concerned with the gas supply issue, and it has been raised in various forums such as NPCC and the North American Electric Reliability Council (NERC).

The potential shutdown or fuel substitution of Lakeview Generating Station by 2005 has not been explicitly considered in this assessment. However, sensitivity studies indicate that the need date for additional resources could be advanced from 2009 to as early as 2006 for the median growth demand scenario.

Figure 1 Winter Peak Resource Outlook – Median Demand Growth



The transmission interfaces studied in this outlook are capable of supplying the various transmission zones under the generation and demand scenarios considered. The IMO recently added the 115kV transmission network to the IMO-controlled grid, and will assess the adequacy of this system in future Outlooks in more detail. The adequacy of the 115kV transmission supply in the IMO-controlled grid, and in particular the adequacy of transmission supply to local areas such as Windsor or Ottawa have not been specifically addressed in this Outlook.

A major transmission addition is committed to be built during the forecast period. A 1,250 MW High Voltage Direct Current (HVDC) interconnection between Ontario and Quebec near Ottawa will improve transfer capabilities between the two provinces. For purposes of this assessment, the interconnection is assumed to be in-service starting in May 2003.

The previously identified Toronto area voltage concern during summer peak periods is not expected to be an issue during the ten year period based on the scheduled return to service of Pickering A generating units and the proposed Sthe resource additions.

Existing congestion is likely to continue on the East – West transmission interface emanating from the Northwest zone when supplying energy to southern Ontario.

With additions of generation in the Sarnia/Windsor area, congestion of up to 2,100 MW can be expected on the transmission lines between Longwood and Buchanan at times when Toronto is being supplied from the West. The amount of Available Resources has been adjusted to reflect expected congestion.

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Table of Contents

Executive Summary.....	i
1.0 Introduction	1
2.0 Forecast of Ontario Electricity Demand.....	3
2.1 Forecasting Process	3
2.2 Forecast Drivers	3
2.3 Forecast of Electricity Energy Demand.....	6
2.4 Forecast of Peak Electricity Demand.....	8
3.0 Resources	11
3.1 Existing Generation Resources Included in the Study.....	11
3.2 Long Term External Transactions Outside the Province	12
3.3 Potential New Generation Resources.....	12
3.4 Summary of Generation Resource Scenarios Assumed in the Study	12
4.0 Resource Assessment	15
4.1 Methodology to Assess Resource Adequacy	15
4.2 Assessment of Resource Adequacy	17
4.3 Conclusions.....	20
5.0 The Ontario Transmission System.....	23
5.1 Overview	23
5.2 Power Transmission Flows across Major Interfaces and Interconnections.....	23
5.3 Proposed New Transmission and Generation Projects	25
6.0 Transmission Adequacy Assessment	29
6.1 Introduction	29
6.2 Reliability Assessment of Transmission Zones	30
6.3 Congestion Assessment	34
6.4 Potential Transmission System Concerns	39
6.5 Impact of Proposed New Generation and Transmission Projects	42
6.6 Conclusions.....	46
7.0 Overall Observations, Findings and Conclusions	49
Appendix A – Electricity Demand Forecast	51
Appendix B – Ontario Electricity System – Maps.....	67
Appendix C – System Resource Details	73
Appendix D – Transmission System Details	85

List of Tables

Table 2.1 Ontario Economic Drivers	5
Table 2.2 Electricity Demand Scenarios	6
Table 2.3 Ontario Energy Demand (Median Economic Growth)	7
Table 2.4 Peak Day and Daily Weather.....	8
Table 2.5A Actual Historical Summer and Winter System Peak Demand	9
Table 2.5B Actual Weather Corrected & Forecast Summer and Winter System Peak Demand .	10
Table 3.1 Existing Installed Generation Resources Assumed in Study.....	11
Table 3.2 Potential Generation Projects in Ontario	12
Table 3.3 Summary of Generation Resource Scenarios Assumed in the Study (at Winter Peak)	13
Table 3.4 Summary of Generation Resource Scenarios Assumed in the Study (at Summer Peak)	13
Table 5.1 Winter 2002 – Generation and Demand by Transmission Zone	24

List of Figures

Figure 1 Winter Peak Resource Outlook – Median Demand Growth	ii
Figure 2.1 Economic Growth Drivers.....	5
Figure 2.2 Annual Energy Demand Forecast – Normal Weather	7
Figure 2.3 Forecast of Monthly Peak Demand	10
Figure 4.1 Reserve Margin	15
Figure 4.2 Resource Adequacy Assessment Graphs.....	22
Figure 5.1 Ontario's Internal Transmission Zones.....	26
Figure 5.2 Ontario's Significant Internal Transfer Interfaces and Points of Interconnection With Neighbouring Areas	27
Figure 5.3 Ontario's Internal Zones and Interconnections	28
Figure 6.1 Conceptual Reliability Model of a Transmission Zone	30
Figure 6.2 Reliability Study – Median Demand Growth, Extreme Weather Scenario	33
Figure 6.3 Congestion Test – West of Toronto.....	35
Figure 6.4 Potential Congestion on NBLIP Interface – 2002 to 2011	36
Figure 6.5 Potential Congestion on FETT Interface – 2002 to 2011	36
Figure 6.6 Congestion Test – North of Toronto	37
Figure 6.7 Potential Congestion on EW Interface – 2002 to 2011	38
Figure 6.8 Potential Congestion on FN/FS Interface – 2002 to 2011.....	38
Figure 6.9 Congestion Test – East of Toronto.....	39

1.0 Introduction

This report presents a 10-year forecast and assessment of generation and transmission facilities in Ontario, the purposes of which are to:

- provide input to relevant standards authorities with respect to their responsibilities for reviewing the status of reliability within each control area,
- provide input to market participants for long-term planning and investment decisions,
- provide input to reports to the Board of Directors of the IMO, the OEB and the Ontario Government regarding projected transmission and generation adequacy,
- provide input to any decisions by the Board of Directors of the IMO regarding the activation and changing requirements of the capacity reserve market.

This report covers the ten year period from January 1, 2002 to December 31, 2011, and is based on the information made available to the IMO from key generator and transmission participants, between December 2000 and March 2001. This report supercedes the previous 10-Year Outlook published by the IMO on August 25, 2000.

The focus of this Outlook is to provide insight into potential investment opportunities, including the need for new or modified IMO-controlled grid facilities to maintain the reliability of the system and to assist the IMO-administered markets to operate efficiently. An outlook period of ten years spans the lead-time to install most new generation and transmission facilities. The assessment of generation adequacy is based upon ensuring that sufficient resources are available to meet the forecast demand plus required reserves. Ontario generation that is available to operate is assumed to supply Ontario demand. The assessment of the adequacy of transmission is based upon ensuring that sufficient transmission capability is available to transmit power to loads in a secure manner with an acceptable degree of reliability.

Section 2 of this report provides a forecast of electricity demand for Ontario. The generation capacity that is expected to be available during the study period is summarized in Section 3 and an assessment of the adequacy of the generation is presented in Section 4. The transmission system that is expected to be available is described in Section 5 and its capability to carry future power transfers is assessed in Section 6. The findings and conclusions of this assessment are contained in Section 7.

Readers are invited to provide comments on this report or to give suggestions as to the content of future reports. To do so, please call the IMO Help Centre at 905-430-6900 or 1-888-448-7777 or send an email to forecasts.assessments@theIMO.com.

2.0 Forecast of Ontario Electricity Demand

The Ontario Demand is the sum of coincident load demands plus the losses on the IMO-controlled grid. Ontario Demand does not include loads that are supplied by embedded generation nor those not supplied from the IMO-controlled grid (e.g. Cornwall Electric).

Section 2.1 describes the process used to forecast electricity demand. Section 2.2 describes the categories of variables that are used to derive the forecast and briefly discusses their relative impacts. Section 2.3 summarizes the electric energy demand forecast, and Section 2.4 summarizes the peak demand forecast. Appendix A contains additional demand forecast details including a monthly demand forecast for the ten year period under consideration. This forecast is consistent with the forecast contained in the IMO's 18-Month Outlook dated April 20, 2001.

2.1 Forecasting Process

The forecast of Ontario electricity demand presented in this outlook was developed by the IMO, in conjunction with Regional Economic Research Inc. (RER). RER was contracted to help the IMO establish its load forecasting capabilities.

The forecasting model utilizes multivariate econometric equations to estimate the relationships between peak and energy demand and a number of independent drivers. The drivers that the model considers are weather effects, economic data and calendar variables. Using regression techniques, the model estimates the relationship between these factors and peak and energy demand. Several calibration routines within the system ensure the integrity of the forecast with respect to energy and peak demand, and regional and system wide projections.

The demand forecasting process provides the following output:

- a forecast of daily 20-minute peak demand for the system and its zones, under Normal, Extreme and Mild weather conditions;
- hourly energy demand by zone under Normal, Extreme, Mild weather conditions; and,
- demand forecast uncertainty as a function of variations in weather.

For the purpose of analysis a variety of economic and weather scenarios were generated. The base case demand forecast is generated using the Median economic forecast in conjunction with Normal weather.

2.2 Forecast Drivers

The forecasted energy demand is based on calendar variables, weather effects and economic conditions. Each of these factors is used in the forecasting system and each plays a role in shaping the results.

Calendar variables include the day of the week and holidays, both of which impact energy demand. Generally, electricity demand is higher during a weekday compared with a weekend day. There is also a pattern determined by the specific day of the workweek. For example, Fridays tend to exhibit the lowest demand during the workweek. Holidays have an electricity

demand that is similar to the demand of a weekend day. The reason for this relationship is that industrial load is lower on holidays and weekends as fewer facilities are operating.

The number of hours of daylight influence the time and magnitude of peak demand. After the sun has set, electricity demand is higher due to the need for electric lighting. This is particularly important when sunset coincides with increases in load associated with cooking and other return to home activities. Hours of daylight are included with calendar variables since forecasting both is very straightforward.

Weather effects include measures of temperature, cloud cover, wind speed and dew point. Both energy and peak demand are weather sensitive. The length and severity of a season's weather contributes to the level of energy consumed and acute weather conditions usually underpin the seasonal peaks.

Three different weather scenarios were used to produce different electricity demand scenarios. Electricity demand scenarios assuming Normal weather, Extreme weather and Mild weather have been forecasted. The Normal weather year is generated from approximately 30 years of historical weather data. Two additional weather scenarios were produced: an Extreme scenario composed of cold winters and hot summers, and a Mild scenario built on warm winters and cool summers. A more detailed description of how this input data is constructed is contained in Appendix A, Section 1.0.

Economic conditions impact the growth of both energy and peak demand. To produce an electricity demand forecast an economic forecast of various drivers was required. Three different economic growth scenarios were used to produce different electricity demand scenarios. Electricity demand assuming Median economic growth, High economic growth and Low economic growth have been forecasted. A consensus of five major, publicly available provincial economic forecasts was utilized to generate the economic drivers used in the model.

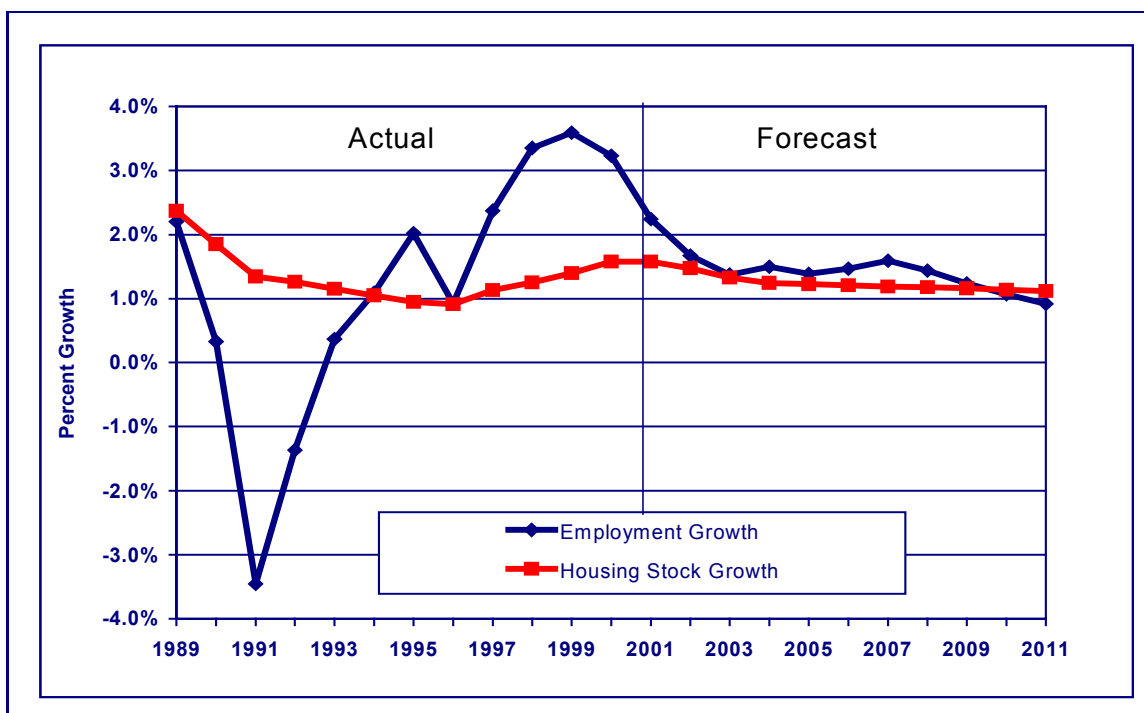
These economic forecasts indicate that overall, the Canadian economy is expected to slow as the U.S. expansion continues to weaken. Continued Federal Reserve rate reductions have led to a rally in confidence and talk of an impending recession has receded from the media headlines. The U.S. economy has weakened however, and is expected to impact Ontario through a reduction in the demand for Ontario produced goods. Continued business investment and domestic consumption will help alleviate some of the decline associated with lower U.S. demand. Therefore, although growth is expected to slow, the overall growth rate remains positive for Ontario and the consensus or Median economic growth forecast reflects that. For the forecast period (2001-2011), the Ontario housing stock is expected to average growth of 1.3% per annum and employment is expected to average growth of 1.4%. Table 2.1 contains the forecast for the key variables of Ontario housing starts and Ontario employment.

Table 2.1 Ontario Economic Drivers

Year	Ontario Employment		Ontario Housing Stock	
	Thousands	Annual Growth (%)	Thousands	Annual Growth (%)
1995	5,128		3,916	
1996	5,175	0.92	3,951	0.91
1997	5,298	2.37	3,996	1.13
1998	5,476	3.35	4,046	1.25
1999	5,672	3.59	4,103	1.40
2000	5,856	3.23	4,167	1.58
2001 (f)	5,987	2.24	4,233	1.58
2002 (f)	6,087	1.67	4,296	1.47
2003 (f)	6,171	1.37	4,353	1.33
2004 (f)	6,263	1.49	4,407	1.24
2005 (f)	6,350	1.39	4,461	1.22
2006 (f)	6,443	1.46	4,514	1.21
2007 (f)	6,545	1.59	4,568	1.19
2008 (f)	6,639	1.43	4,622	1.17
2009 (f)	6,721	1.24	4,675	1.16
2010 (f)	6,793	1.07	4,729	1.14
2011 (f)	6,855	0.92	4,781	1.12

Notes to Table 2.1:

The (f) indicates years when forecast data is shown. Other years show actual data.

Figure 2.1 Economic Growth Drivers

For the purposes of analysis two additional economic forecasts - a Low economic growth scenario and a High economic growth scenario - were developed and used to generate demand scenarios. The Low growth scenario assumes that the economy slips into recession at the end of 2001 before recovering in 2004. The High economic growth scenario assumes much higher sustained growth over the length of the entire forecast period. Appendix A2 contains more detail on the economic scenarios.

Scenarios: In total, nine different **Demand Scenarios** are produced. Not all of the demand forecast scenarios were used in every assessment study. The matrix below shows the scenarios and the sections of the outlook in which they are used.

Table 2.2 Electricity Demand Scenarios

		Economic Scenarios		
		<u>Low Growth</u>	<u>Median Growth</u>	<u>High Growth</u>
Weather Scenarios	<u>Mild Weather</u>	Not used in report	Not used in report	Not used in report
	<u>Normal Weather</u>	Resource Adequacy (Section 4.2.1)	Resource Adequacy (Section 4.2.2) Transmission Adequacy (Section 6.3)	Resource Adequacy (Section 4.2.3)
	<u>Extreme Weather</u>	Not used in report	Transmission Adequacy (Section 6.2 and Section 6.4)	Transmission Adequacy (Section 6.2)

2.3 Forecast of Electricity Energy Demand

Energy demand has grown at an average annual rate of 1.6% over the period 1986-2000. The forecast energy demand and corresponding growth rates for the time frame 2001-2011 are detailed in Table 2.1. Figure 2.2 graphically displays energy demand on an annual basis. Energy demand is expected to increase at an average annual rate of 1.2% over the forecast period. The growth in demand is driven by changes in economic activity, the number of end-users and the penetration of electric powered devices.

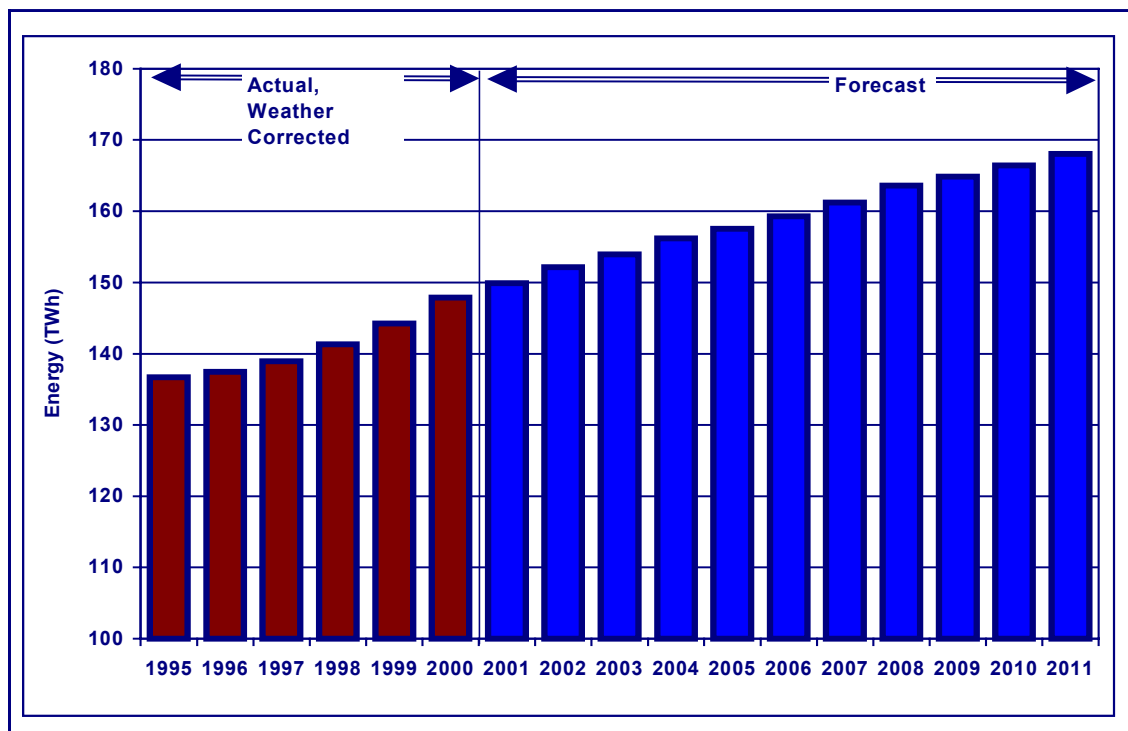
Although this section of the report deals with summary details at the total Ontario system level, the demand forecast contains hourly detail for nine transmission zones. A forecast of zonal energy demand is provided in Appendix A, Table A1 and a map showing the zones is located in Appendix A in Figure A1. Since economic cycles affect different parts of the Ontario economy to varying degrees and at different times, growth is not consistent across the zones. Additional information of energy demand under the various economic scenarios is included in Appendix A.

Table 2.3 Ontario Energy Demand (Median Economic Growth)

Year	Normal Weather		Actual Weather	
	Energy Demand (TWh)	Annual Growth (%)	Energy Demand (TWh)	Annual Growth (%)
1995	136.7		137.0	
1996	137.4	0.55	137.4	0.28
1997	139.0	1.10	138.4	0.69
1998	141.3	1.70	139.9	1.13
1999	144.2	2.07	144.1	2.97
2000	147.9	2.51	146.9	1.98
2001 (f)	149.9	1.37		
2002 (f)	152.1	1.48		
2003 (f)	154.0	1.21		
2004 (f)	156.2	1.45		
2005 (f)	157.6	0.87		
2006 (f)	159.3	1.09		
2007 (f)	161.2	1.20		
2008 (f)	163.6	1.49		
2009 (f)	164.8	0.77		
2010 (f)	166.4	0.97		
2011 (f)	168.0	0.96		

Note to Table 2.3:

No forecasts of actual weather conditions are made. The electricity energy demand forecast is predicated on Normal weather conditions.

Figure 2.2 Annual Energy Demand Forecast – Normal Weather

2.4 Forecast of Peak Electricity Demand

Historically, Ontario's electricity peak demand has occurred during the winter, usually in the months of December, January or February and between the hours of 5 p.m. to 7 p.m. Exceptions to this were in 1998 and 1999, when the annual peak demand occurred during a July afternoon. The occurrence of this summer vs. winter peak demand is attributed to a warmer than normal winter and unusually hot summer weather as a result of El Nino and La Nina. The actual Ontario all-time 20-minute peak demand reached 24,007 MW in January 1994. The peak of 23,435 MW in July 1999 was the highest summer peak experienced by the system. Actual 20-minute peak demands that occurred in the summer and winter of year 2000 were 23,222 MW in August and 23,428 MW in January. The winter and summer peak demands are very weather dependent and usually coincide with extreme weather conditions. Excluding weekends and holidays, the winter peak has occurred on the day with the most extreme weather – based on the Temperature Humidity Index – nine times since 1985. Of the remaining seven years the winter peak has occurred on the day with the second most extreme weather four times. The summer peak is less consistent, occurring on the most extreme day only five times since 1985. Table 2.4 lists the summer and winter peaks along with the daily weather ranking, in terms of hottest or coldest days.

Table 2.4 Peak Day and Daily Weather

Year	Peak Day Summary			
	Summer Peak Date	Daily Weather Ranking	Winter Peak Date	Daily Weather Ranking
1985	14-Aug	3	21-Jan	1
1986	07-Jul	2	27-Jan	2
1987	17-Aug	4	08-Dec	8
1988	04-Aug	3	14-Jan	1
1989	10-Jul	5	04-Jan	1
1990	04-Jul	1	13-Dec	7
1991	29-Aug	9	21-Jan	1
1992	26-Aug	2	16-Jan	1
1993	27-Aug	2	01-Feb	1
1994	17-Jun	1	19-Jan	1
1995	15-Aug	3	06-Feb	1
1996	07-Aug	1	11-Dec	13
1997	14-Jul	1	17-Jan	1
1998	15-Jul	2	14-Jan	2
1999	05-Jul	1	13-Jan	2
2000	31-Aug	2	17-Jan	2

Note to Table 2.4:

Daily weather ranking is based on the Temperature Humidity Index (THI) and excludes weekends and holidays. The ranking denotes coldest to warmest days for winter and hottest to coolest for summer.

The variation in terms of the impact of extreme weather in the summer is due to, in part, to summer vacations and plant shutdowns mitigating some of the impact of the extreme weather conditions on peak demand. However, the trend in summer peak has been towards the more extreme days. Since 1996, the peak day has coincided with either the most or second most

extreme day. This can be attributed to the increased penetration of air conditioning in the residential sector. With the lack of any feasible substitute for electric air conditioning, the increased use of air conditioning is making energy demand more responsive to hot weather conditions. This results in stronger growth in the summer peak demand. Over the 1986-2000 time frame, the actual summer peak demand has averaged growth of 2.3%, which is much stronger than that of the winter peak demand which has average growth of 0.9% over the same time. These growth rates are exaggerated by the milder winters and hotter summers experienced over the latter part of the 1990's. Despite the trend in summer peak, the system is expected to remain winter peaking throughout the forecast period. Tables 2.5A and 2.5B contain the summer and winter peak demands and Figure 2.3 displays the monthly peak demands over the forecast period. Appendix A, Section 4.0 provides additional detail on the zonal peaks. As referenced earlier, a number of demand scenarios were developed for assessment purposes. Figures A5 and A6 in Appendix A depict the summer and winter peaks under both Normal and Extreme weather, as well as under Median and High economic growth.

Table 2.5A Actual Historical Summer and Winter System Peak Demand

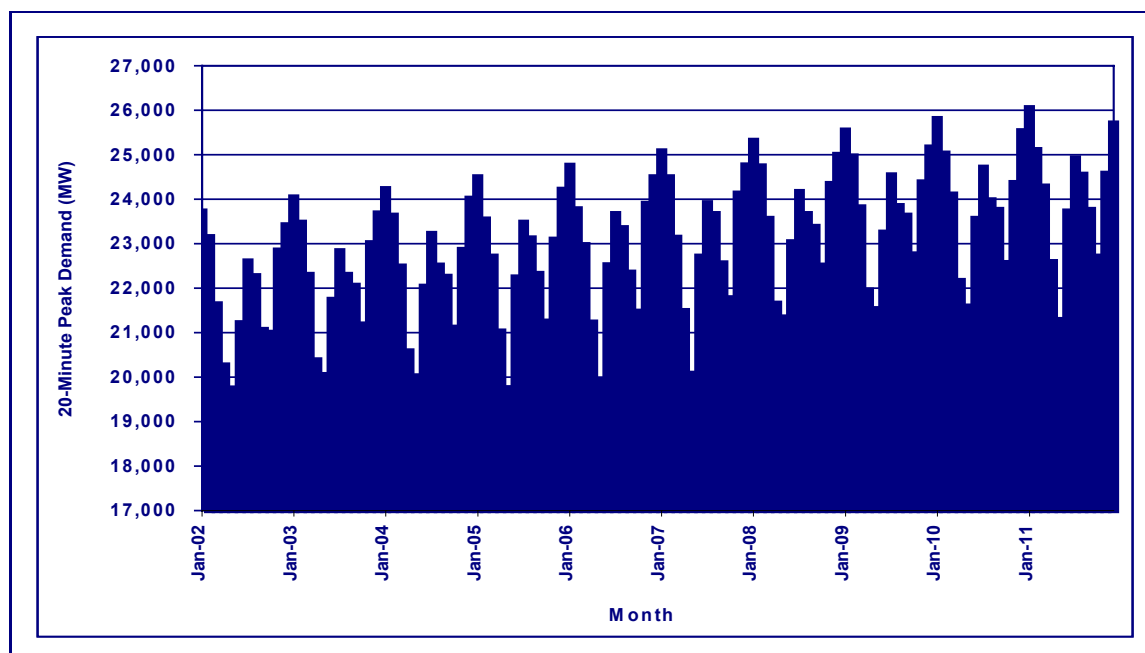
Year	Actual Summer Peak Demand (MW)	Annual Growth (%)	Actual Winter Peak Demand (MW)	Annual Growth (%)	Summer / Winter Peak Demand Ratio
1990	20,453		23,630		0.866
1991	21,150	3.41	23,212	-1.77	0.911
1992	19,976	-5.55	23,540	1.41	0.849
1993	20,937	4.81	22,087	-6.17	0.948
1994	20,923	-0.07	24,007	8.69	0.872
1995	21,770	4.05	22,855	-4.80	0.953
1996	21,428	-1.57	22,321	-2.34	0.960
1997	21,667	1.12	22,197	-0.56	0.976
1998	22,443	3.58	22,067	-0.59	1.017
1999	23,435	4.42	23,308	5.62	1.005
2000	23,222	-0.91	23,428	0.51	0.991

Table 2.5B Actual Weather Corrected & Forecast Summer and Winter System Peak Demand

Year	Weather Corrected Summer Peak Demand (MW)	Annual Growth (%)	Weather Corrected Winter Peak Demand	Annual Growth (%)	Summer / Winter Peak Demand Ratio
1995	19,478		22,121		0.881
1996	19,386	-0.47	21,567	-2.50	0.899
1997	20,074	3.55	21,964	1.84	0.914
1998	20,621	2.72	21,960	-0.02	0.939
1999	20,373	-1.20	22,450	2.23	0.907
2000	21,438	5.23	23,284	3.71	0.921
2001 (f)	22,333	4.18	23,149	-0.58	0.965
2002 (f)	22,611	1.24	23,731	2.52	0.953
2003 (f)	22,841	1.02	24,051	1.35	0.950
2004 (f)	23,228	1.69	24,232	0.75	0.959
2005 (f)	23,482	1.09	24,507	1.14	0.958
2006 (f)	23,674	0.82	24,761	1.04	0.956
2007 (f)	23,921	1.04	25,086	1.31	0.954
2008 (f)	24,170	1.04	25,325	0.95	0.954
2009 (f)	24,549	1.57	25,558	0.92	0.961
2010 (f)	24,715	0.68	25,815	1.01	0.957
2011 (f)	24,933	0.88	26,057	0.94	0.957

Notes to Table 2.5B:

The forecast for Winter 2001 is the peak value for December 2001. January 2001 had an actual peak of 22,672 MW (22,887 MW for Normal weather). Peaks are reported on a calendar year basis. As a result, the winter peak can occur at the beginning of the year, January through March, or at the end of the year, in November or December. Forecasted system winter peaks occur in January. Weather corrected values are the actual peak values adjusted to reflect demand under typical weather conditions for that period.

Figure 2.3 Forecast of Monthly Peak Demand

3.0 Resources

This section describes the generation resources that are forecast to be available in the ten-year study period.

Section 3.1 describes the capacity of the existing installed generation resources that were included in the study. Section 3.2 describes the long-term bilateral external transactions (imports and exports) that were considered. Section 3.3 summarizes new generation projects in Ontario, which have been identified to the IMO through the Connection Assessment and Approval (CAA) process. Input information related to the specific generation projects was originally collected in January 2001, and remains consistent with the list of projects identified as of May 8, 2001. Section 3.4 provides an overall summary of the total resources that were included in the study, taking into account the existing generation, external transactions and the generation resource additions under various scenarios.

3.1 Existing Generation Resources Included in the Study

The existing installed generation included in the study is summarized in Table 3.1. It includes nuclear, coal, oil, gas, hydroelectric, wind-powered, wood and waste-fuelled generation. The installations range in size from less than 1 MW to 881 MW and result in a total capacity of 29,492 MW. Not included in the study are embedded generators that are not managed by Ontario Electricity Financial Corporation (OEFC) or generation not directly connected to the IMO-controlled grid.

Although announcements have been recently made about the intention of Bruce Power to return to service two of the Bruce A units, the capacity of installed generation resources used for the present study does not include Bruce A units, which are currently in laid-up state. These units will be included in future studies when their proposed restart has been submitted to the IMO for Connection Assessment and Approval.

All the listed generation in Table 3.1 is considered operational through the study period, except for the Pickering A nuclear units. They are forecast by Ontario Power Generation Inc. (OPGI) to return to service starting in 2002.

Table 3.1 Existing Installed Generation Resources Assumed in Study

Resource Type	Total, MW	# of Stations	Size Range, MW
Nuclear	10,788	4	515 - 881
Coal	7,533	5	153 - 490
Oil / Gas	3,706	32	<1 - 535
Hydroelectric	7,428	128	<1 - 136
Miscellaneous (wind, waste, wood, etc.)	37	5	1 - 40
Total	29,492	174	<1 - 881

3.2 Long Term External Transactions Outside the Province

Availability of 650 MW of firm capacity external to Ontario was included in the assessment for the period from January 1, 2002 through January 31, 2002. For the period from February 1, 2002 through April 30, 2002, an amount of 700 MW of firm external capacity was considered available. From May 1, 2002 through October 31, 2003 200 MW of firm external capacity was included in the assessment. No other firm purchase contracts have been identified for the study period. There are no firm sales identified at any point in the study period.

3.3 Potential New Generation Resources

In accordance with the Market Rules set for the new Ontario marketplace, Chapter 4, Section 6, anyone planning a new or modified connection to the IMO-controlled grid must apply to the IMO for approval under the Connection Assessment and Approval (CAA) process.

Table 3.2 summarizes potential new generation projects that have been identified to the IMO through the CAA process. The CAA Status column shows the status of each project; SIA means the System Impact Assessment has been completed or is in progress, while PA means the Preliminary Assessment has been completed or is in progress.

Table 3.2 Potential Generation Projects in Ontario

Project Name	System Zone	Resource Type	Capacity MW	Estimated I/S Date	CAA Status
Enron	West	Gas	219	2001 - Q2	SIA
AGSTAR ¹	West	Gas	88	2001 - Q4	PA
Enron	West	Gas	286	2002 - Q2	SIA
Transalta	West	Gas	491	2002 - Q3	SIA
Northland (Kirkland)	Northeast	Gas	48	2002 - Q4	SIA
Northland (Thorold)	Niagara	Gas	296	2003 - Q1	PA
Sithe Goreway	Toronto	Gas	932	2003 - Q2	SIA
ATCO	West	Gas	578	2003 - Q2	SIA
Calpine Coruna	West	Gas	870	2003 - Q2	PA
AGSTAR ¹	West	Gas	538	2003 - Q4	PA
AES	West	Gas	531	2003 - Q4	SIA
Sithe Southdown	Toronto	Gas	763	2004 - Q1	SIA
Imperial Oil	West	Gas	212	2004 - Q3	PA
Total			5852		

Note to Table 3.2:

1. The AGSTAR project was previously identified as the Agro Sun project, in the IMO latest 18-Month Outlook IMO_REP_0013v1.0.

Details about the CAA process, the status of all current applications, including copies of available Preliminary Assessment (PA) and System Impact Assessment (SIA) Reports can be found on the IMO's web site www.theIMO.com under the "Connection Assessments" link.

3.4 Summary of Generation Resource Scenarios Assumed in the Study

In assessing future resource adequacy, it is necessary to make a number of assumptions regarding the magnitude of supply resources that will be available. This Outlook assumes three different scenarios regarding the installed resources.

Tables 3.3 and 3.4 show the three generation resource scenarios assumed in the study, at the time of the winter and summer peak demands. These scenarios have been developed starting from a base case comprised of the existing installed generation resources shown in Table 3.1 plus the firm external transactions described in section 3.2. The sum of the existing capacity and the firm transactions represents Resource Scenario #1. Since it represents an electricity supply case in which no generation additions will occur during the 10-year study period, Scenario #1 is considered to be a conservative case.

Resource Scenario #2 has been developed by adding to Resource Scenario #1 the amount of capacity from generation projects currently in the SIA phase (SIA complete or in progress). Resource Scenario #3 was derived from Resource Scenario #1 by adding all potential generation projects shown in Table 3.2 (projects in either the SIA or PA phase). Both Scenarios #2 and #3, present increasingly optimistic generation resource outlooks. In creating Scenarios #2 and #3, the availability of each generation project to contribute to the seasonal peak in each year has been determined by the estimated I/S date shown in Table 3.2.

The Market Rules obligate Market Participants to give six months notice of retirements. No such notices have been received by the IMO. Although the government has proposed that the Lakeview Generation Station cease burning coal by April 2005, this outlook assumes its continued availability, until the owners of the facility indicate any alternate plans, such as retirement or outages to allow for fuel conversion.

Table 3.3 Summary of Generation Resource Scenarios Assumed in the Study (at Winter Peak)

Notes	Description \ Year	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
1	Installed Resources	29,492	29,492	29,492	29,492	29,492	29,492	29,492	29,492	29,492	29,492
2	Firm Import	650	200	0	0	0	0	0	0	0	0
3	(SIA) Additions	219	1,044	3,085	3,848	3,848	3,848	3,848	3,848	3,848	3,848
4	(SIA + PA) Additions	307	1,132	4,877	5,852	5,852	5,852	5,852	5,852	5,852	5,852
5	Resource Scenario #1	30,142	29,692	29,492	29,492	29,492	29,492	29,492	29,492	29,492	29,492
6	Resource Scenario #2	30,361	30,736	32,577	33,340	33,340	33,340	33,340	33,340	33,340	33,340
7	Resource Scenario #3	30,449	30,824	34,369	35,344	35,344	35,344	35,344	35,344	35,344	35,344

Table 3.4 Summary of Generation Resource Scenarios Assumed in the Study (at Summer Peak)

Notes	Description \ Year	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
1	Installed Resources	29,492	29,492	29,492	29,492	29,492	29,492	29,492	29,492	29,492	29,492
2	Firm Import	200	200	0	0	0	0	0	0	0	0
3	(SIA) Additions	505	2,554	3,848	3,848	3,848	3,848	3,848	3,848	3,848	3,848
4	(SIA + PA) Additions	593	3,808	5,640	5,852	5,852	5,852	5,852	5,852	5,852	5,852
5	Resource Scenario #1	29,692	29,692	29,492	29,492	29,492	29,492	29,492	29,492	29,492	29,492
6	Resource Scenario #2	30,197	32,246	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
7	Resource Scenario #3	30,285	33,500	35,132	35,344	35,344	35,344	35,344	35,344	35,344	35,344

Notes to Tables 3.3 and 3.4:

1. Installed Resources: This is the total capacity of the existing installed generation resources in Ontario assumed to be operational over the summer and winter peaks in the next 10 years, as described in section 3.1. This value includes all the generation in Ontario, except Bruce A, retired generation and

embedded generators not managed by OEFC or generation not directly connected to the IMO-controlled grid.

2. Firm Import: Represents the amount of firm capacity purchase to be delivered into Ontario under existing contracts.
3. (SIA) Additions: The amount of capacity identified with generation projects in the SIA stage available for the summer and winter peaks in each year is shown on a cumulative basis.
4. (SIA + PA) Additions: The amount of capacity identified with generation projects in the SIA and PA stages available for the summer and winter peaks in each year is shown on a cumulative basis.
5. Resource Scenario #1: This is the sum of lines 1 and 2 above.
6. Resource Scenario #2: This is the sum of lines 1, 2 and 3 above.
7. Resource Scenario #3: This is the sum of lines 1, 2 and 4 above.

4.0 Resource Assessment

This section provides an assessment of the adequacy of the resources described in Section 3 to meet the forecast demand described in Section 2. The methodology used to carry out this assessment is summarized in Section 4.1 and described in more detail in Appendix C. Results of the adequacy assessment are described in Section 4.2 and conclusions are provided in Section 4.3.

4.1 Methodology to Assess Resource Adequacy

4.1.1 Resource Adequacy Standard

The IMO, as a member of the NPCC, is expected to demonstrate that it can achieve the following resource adequacy standard:

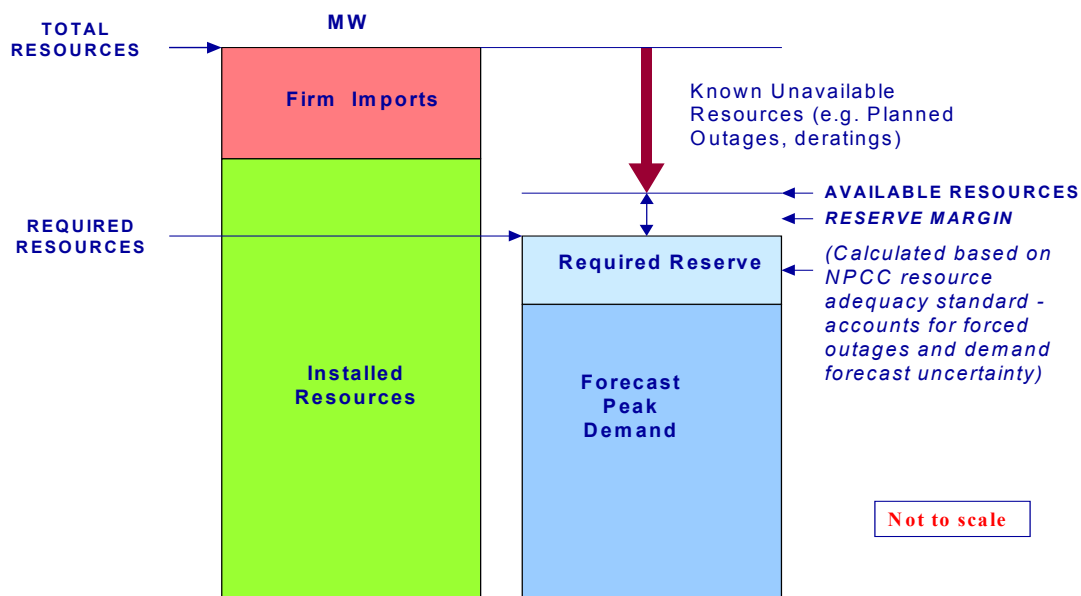
"...after due allowance for scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and regions, and capacity and/or load relief from available operating procedures, the probability of disconnecting non-interruptible customers due to resource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

The IMO employs an NPCC-accepted variation of this standard, which is a Loss of Load Expectation of not more than 0.1 days per year.

Reserve resources are required to ensure that the forecast demand can be supplied with a sufficiently high level of reliability. The amount of Required Reserve is calculated to meet the requirements of the NPCC resource adequacy standard. The Required Resources are the amount of resources required to supply the peak demand and meet the Required Reserve.

The Reserve Margin is the difference between Available Resources and Required Resources as illustrated in Figure 4.1.

Figure 4.1 Reserve Margin



It should be noted that the Required Reserve is a planning parameter. In day to day operation the available resources must cover the demand plus the Operating Reserve, which for Ontario is about 1,350 MW, depending on the size of the largest generating units in service.

4.1.2 How the Criterion Was Applied

The Required Reserve in MW was calculated, using probabilistic techniques, for each week in the assessment period based on the resource adequacy standard described above, using the IMO's Load and Capacity Program (see Appendix C for further details).

The adequacy of the available resources to meet the demand over the study period was assessed, in a deterministic calculation, as shown in Figure 4.1. For each planning week, the minimum level of Available Resources was determined, starting with the total resources then subtracting generator deratings, planned and long term unplanned generator outages, generation constrained off due to transmission interface limitations and allowances for non-utility and hydroelectric generation production below rated capacity. The Reserve Margin was then obtained by subtraction of the Required Resources (equal to Demand plus Required Reserve) from the minimum Available Resources. Whenever the Reserve Margin is positive the reliability criterion is met or exceeded.

Available Resource values include external resources backed by firm purchase contracts. The inclusion of only firm purchases in the assessment represents a conservative assumption. External generation of up to 1,000 MW outside peak demand periods is reasonably expected to be available to bid into the Ontario market, in the case of resource shortfalls, as a response to market prices. During winter peak periods, although Canadian systems face their highest demands, other Northeast systems often have spare capacity. External resources of up to 700 MW can usually be relied upon at winter peak periods. This assumption is supported by a recent load and capacity assessment study performed by the East Central Area Reliability Region (ECAR), which forecasts an ECAR Reserve Margin of about 2,600 MW at the time of the 2002 winter peak demand in Ontario. During Ontario summer peak demand periods of July and August, experience has shown that the summer peaking systems of NPCC are often also at their peak demand with both generation and transmission systems at their limits. Therefore no reliance is placed upon external generating capacity in July and August unless it is backed by firm purchase contracts.

Demand values include loads that can be dispatched off or otherwise interrupted in the case of a shortfall in reserves. For modeling purposes, the dispatchable demand was assumed to be supplied, and was included in the peak demand forecast when the Required Reserve was probabilistically calculated. At the deterministic assessment stage, dispatchable demands and interruptible loads were deducted from the peak demand. A value of 300 MW was assumed for interruptible or dispatchable demands based on past operational experience. The IMO expects to be in a better position to forecast dispatchable demand levels as Market Participant registration progresses and market experience is gained.

4.1.3 Description of the Scenarios Studied

The Resource Adequacy Assessment Scenarios were created using the total generation resources derived in the three Resource Scenarios in Section 3.4. For each Resource Scenario, generator deratings, planned and long term unplanned generator outages, generation constrained off due to

transmission interface limitations and allowances for non-utility and hydroelectric generation production below rated capacity were subtracted from total generation resources to obtain the Available Resources in each week of the study period.

For 2002 only, specific participant generator outage plans have been used. These plans include generator outages scheduled over the summer and winter peak periods in 2002. For the period 2003 through 2011, explicit generator outage plans are unavailable. For these years it is necessary to model a hypothetical outage plan which reflects known cyclic outages (such as nuclear station vacuum building inspections) and planned outage factors supplied by generator participants. This is referred to as a “generic” outage plan to reflect the fact the majority of assumptions are modeled repetitively for nine of the ten years studied. In the generic outage plan no generator outages have been assumed to be scheduled at the summer and winter peaks. The assumption of no outages over peak periods is grounded as possible only as long as outage durations are such to permit their scheduling outside of the peak periods. Based on current knowledge of participant outage cycles this is feasible. However, should outage durations grow, as might be required for rehabilitation activities or for installation of emission reduction facilities, the IMO expects increasing pressure to accommodate outages over peak periods. As reserve margins increase, through the addition of resources to the IMO-controlled grid, the ability to accept outages over peak periods will improve. The IMO deals with the scheduling of explicit outage plans in the 18-Month Outlooks, where participants are expected to request outage time based on the availability of suitable resource margins.

The Forecast Demand Scenarios used to perform the adequacy assessment are the Low, Median and High Demand Growth, Normal Weather Scenarios, as described in Section 2. A comprehensive analysis has been carried out for the combination of the three Demand Growth scenarios and Resource Scenario #1. The results from Resource Scenarios #2 and #3 have been assessed using an approximate calculation based on adding to the Reserve Margins in Scenario #1 the improvement resulting from the generation additions in each of the two resource scenarios. It must be noted that the Reserve Margin improvement is not always equal to the amount of the generation additions. This is due to the large amount of planned generation additions in the West zone of the IMO-controlled grid, which will likely cause some generation to be constrained off because of congestion of the Negative Buchanan Longwood Input (NBLIP) transmission interface. The potential amount of constrained generation varies, at the time of seasonal peaks, between 0 MW under Resource Scenario #1 and about 2,100 MW under Resource Scenario #3, depending on the demand level and the total amount of generating capacity in the West zone. Congestion will be greatest during low demand or off-peak periods unless generators take advantage of these opportunities to perform maintenance or to market some portion of their output to the US (i.e. via the Ontario – Michigan interconnection). See Section 6.3.2 for transmission related aspects of congestion on this interface.

4.2 Assessment of Resource Adequacy

Graphical results of the Resource Adequacy Assessment are shown in Figure 4.2 and described in Sections 4.2.1 through 4.2.4. Result tables and more technical details can be found in Appendix C.

4.2.1 Resource Adequacy under Low Demand Growth Scenario

Over the forecast period, the Ontario electrical energy use, under the Low Demand Growth Scenario, is expected to increase, on average, by 0.8% annually.

The adequacy analysis shows that the Ontario System would have sufficient resources to meet forecast demands plus the Generation Reserve Requirements for each year during the forecast period under all resource scenarios. The estimated LOLE for each year is well within the NPCC resource adequacy standard.

At the time of 2002 winter and summer peaks, under Resource Scenario #1 only, the reserve levels are shown to be slightly lower than desired. It is expected that reliability requirements will be met with an appropriate combination of maintenance outage adjustments and an increased supply from regions adjacent to Ontario. The potential requirement for remedial actions will be reviewed early in 2002.

4.2.2 Resource Adequacy under Median Demand Growth Scenario

Under the Median Demand Growth Scenario, Ontario electrical energy use is expected to increase, on average, by 1.2% annually over the 10-year period. This is considered to be the most likely scenario.

The adequacy analysis shows that the Ontario System would have more than enough resources to meet Forecast Demands plus the Generation Reserve Requirements for each year during the forecast period under Resource Scenarios #2 and #3. High levels of reserve are expected, beginning early in 2003 and continuing to 2011. A high degree of flexibility should exist for conducting maintenance programs and for supplying both Ontario and external markets in a competitive manner. The estimated LOLE for each year is well within the NPCC resource adequacy standard.

For the 2002 winter and summer peaks under Resource Scenario #1, it is expected that reliability requirements will be met with an appropriate combination of maintenance outage adjustments and an increased supply from regions adjacent to Ontario, if necessary, to avoid reserves falling below desired levels. The estimated LOLE for 2002 suggests that the Ontario electricity system reliability will be better than required by the NPCC resource adequacy standard.

By the year 2009, under Resource Scenario #1, Reserve Margins over peak periods are again forecast to drop below desired levels, indicated an increasing dependency on external resources. Starting in 2009, the estimated LOLE's to 2011 are higher than 0.1 days/year, suggesting that maintaining the supply reliability will require the addition of new generating capacity, development of demand side management programs or dispatchable demand by Market Participants, or external resources supplying Ontario.

4.2.3 Resource Adequacy under High Demand Growth Scenario

For the High Demand Growth Scenario, Ontario electrical energy is expected to increase, on average, by 1.7% annually.

At peak periods in 2002, should the High Demand Growth Scenario materialize, there is an increased likelihood that the IMO will be required to curtail planned generation and transmission

outages, and that external generation will be required to supply loads within Ontario, to avoid having reserves fall below the desired level. The amount of external generation potentially required is well within the tie line import capability and within the amounts of generation normally expected to be available from neighbouring systems. The estimated LOLE for 2002 is lower than 0.1 days/year, which indicates that the Ontario electricity system will be operated within the NPCC adequacy standard.

Under Resource Scenario #1, Ontario resources are forecast to be adequate until early in 2006 when reserve levels drop below desired levels, with the deficiencies increasing through 2011. Without generation additions within Ontario or price responsive demand development, substantial support from regions adjacent to Ontario would likely be required to meet NPCC reserve requirements.

Under Resource Scenarios #2 and #3, with generation additions, the resource adequacy picture in 2003 and beyond looks to be more than sufficient to meet the demands of Ontario, even with the higher projected growth.

4.2.4 Other Scenarios

There are several other situations that could cause the amount of the available resources to change from the assumptions used in the analysis in Sections 4.3.1, 4.3.2 and 4.3.3. Typical changes to the assumed available generation, such as delays in generation construction, generating unit retirements, different planned maintenance schedules or higher forced outages, could change the Reserve Margin values substantially. To illustrate the impact these risks might have on Reserve Margins, Tables C2.7 to C2.12 have been provided in Appendix C and include the resulting Reserve Margins if the available generation resources are lower by 1,000 MW and 2,000 MW, respectively, than the forecast amount under Scenario #1. It should be recognized that there are also various scenarios that could result in improvements in the reliability in the Outlook period, including the return of Bruce A units, or additional generation facilities proposed and placed in-service.

4.2.5 Impact of Emission Regulations

The “Coal-Fired Electricity in Ontario” report issued by Ministry of Environment in March 2001, shows that the fossil-fuelled plants are responsible for a high percentage of pollutant emissions in Ontario. The report also notes that OPGI has made and is committed to making important steps in reducing these emissions. However, the conclusions and recommendations did not provide the IMO with sufficient input data for a comprehensive impact assessment study.

To perform a comprehensive study, participant specific input data would be required by the IMO from the generators, and participants would need to provide short and long-term generator outage plans to accommodate emission-related modifications or fuel conversion. The IMO would need to make some judgmental assumptions, as well, to predict expected behavioural changes with bidding, and emission limit trading. Timely access to this data was not available for this Outlook.

Without the benefit of specific studies, it is expected that installation of the remedial measures identified in the report will permit continued operation of most coal-fired plant to the levels required by Ontario demand. Some impact on maintenance outage schedules can be expected but these will likely be incorporated to the extent possible with other routine work. Conversion of

coal-fired plant to other fuels may require longer outages and impact reserves over peak periods if longer than a few months in duration. With current expectations for resource additions, these will likely not be problematic. Without any resource additions in Ontario, emission-related limitations of coal-fired generation would be expected to result in increased reliance on external sources of supply to meet Ontario demand requirements.

4.3 Conclusions

Reserve levels are generally forecast to be higher in the summer than in the winter, mainly because of the higher peak demands in the winter.

Based on current knowledge of participant outage cycles, outages can be scheduled to avoid the peak periods. However, should outage durations grow, as might be required for rehabilitation activities or for installation of emission reduction facilities, the IMO expects increasing pressure to accommodate outages over peak periods. As reserve margins increase, through the addition of resources to the IMO-controlled grid, the ability to accept outages over peak periods will improve.

In 2002 the estimated LOLE is lower than 0.1 days/year, which shows that the Ontario electricity system will be operated within the NPCC adequacy standard. At the time of the winter and summer peaks, a suitable combination of generator outage shifts and additional external resources supplying the Ontario market, will be sufficient to avoid reserves falling below the desired level. While generator outage shifts provide more resource management capability during the summer months, external capacity is expected to offer more support during the winter months. A recent load and capacity assessment study performed by the East Central Area Reliability Region (ECAR) forecasts a Reserve Margin of about 2,600 MW at the time of the 2002 winter peak demand in Ontario, supporting this conclusion.

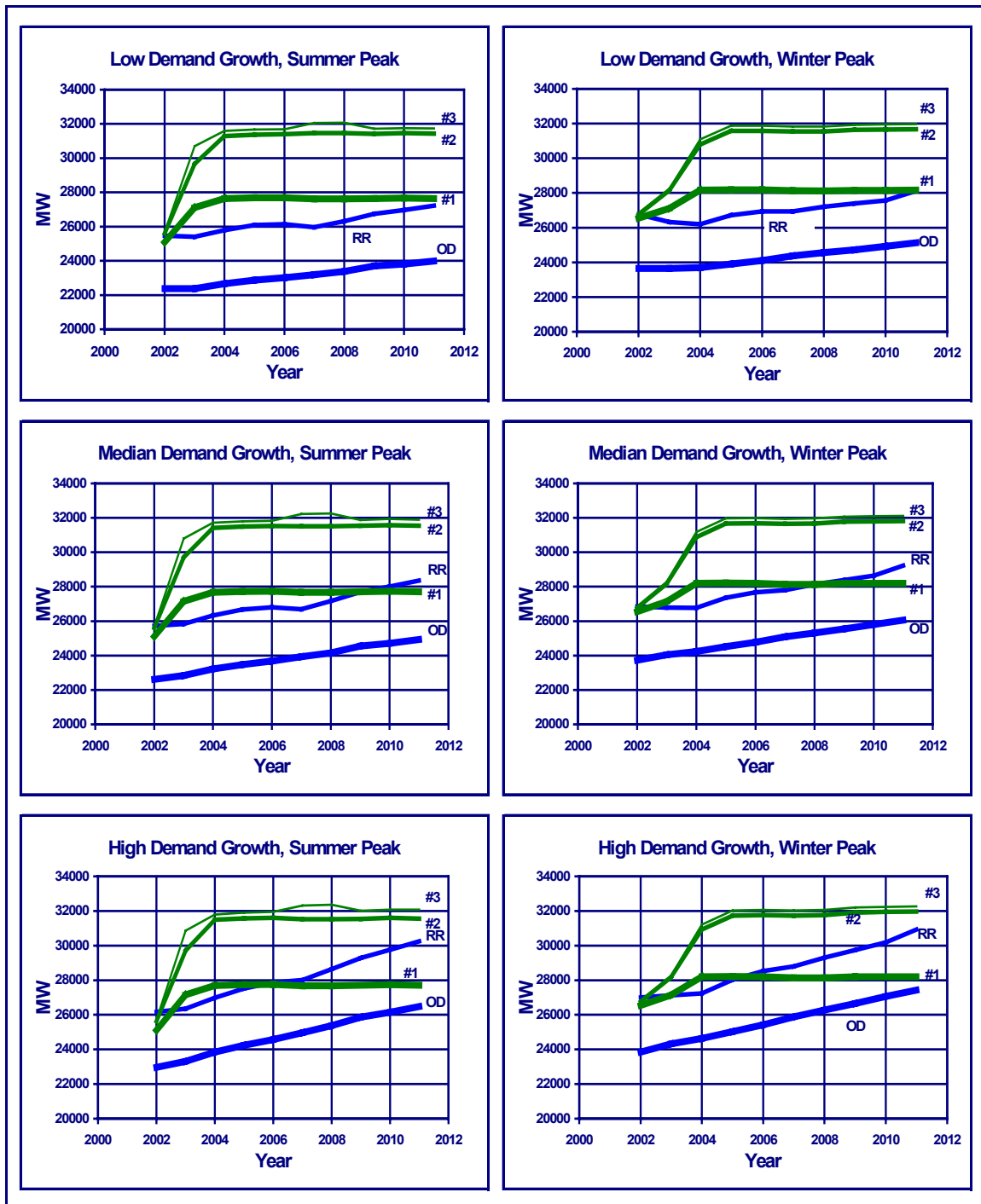
Resource Scenario #1 should provide adequate reserve levels in all years under the Low Demand Growth Scenario. Under the Median Demand Growth scenario reserve levels would be expected to become lower than desired in 2009, with increasing deficiencies going out toward 2011. However, the lower reserve would be less problematic if sufficient dispatchable demand materializes to respond to spot market prices or if resources from neighbouring areas offer generation in the Ontario market. Any combination of these two measures which totals 1,000 MW would be sufficient to restore reserves to desired levels. Under the High Demand Growth Scenario, reserves would be low starting early in 2006, causing an increasingly large dependency on external resources over peak periods.

Resource Scenarios #2 and #3 yield high reserve levels beginning in 2002 and continuing through 2011 with the above mentioned exception of winter and summer peak of 2002. No reliability concerns would arise in these cases beyond 2002.

In summary, the resource adequacy picture for Ontario should remain healthy over the next ten years if a substantial portion of the proposed additions, which have been submitted to the IMO for Connection Assessment and Approval, are constructed.

There is a need for generation resource additions toward the middle to end of the study period, especially in the event of high demand growth. The benefits of these additions include, but are not necessarily limited to, a decrease in Ontario dependency on external resources (especially at

seasonal peaks), increased generator outage scheduling flexibility, and a greater degree of competitiveness to supply Ontario and other electricity markets.

Figure 4.2 Resource Adequacy Assessment Graphs**Notes to Figure 4.2:**

- #1 – Represents the Available Resources under Resource Scenario #1.
- #2 – Represents the Available Resources under Resource Scenario #2.
- #3 – Represents the Available Resources under Resource Scenario #3.
- OD – Represents the Ontario winter/summer peak demand.
- RR – Represents the generation resources required to meet the peak demand and the Generation Reserve Requirement.

5.0 The Ontario Transmission System

5.1 Overview

As shown in Appendix B, the Ontario transmission system has been developed over the years to transfer power in bulk from point to point in Ontario and across interconnections to neighbouring jurisdictions. This system provides transmission circuits that will facilitate competition among suppliers, once the Ontario market is opened. Generally, the transmission system is robust but there are some limits on the amount of power that can be transferred across certain groups of critical circuits called interfaces. These transfer limits are based on both the physical limitations of the circuits and the need to respect various system security criteria, such as criteria established by NERC and NPCC.

The current capability of the Ontario transmission system is described briefly in the following sections. Figures 5.1 and 5.2 provide a geographic depiction of Ontario's internal transmission zones. These internal zones have been defined by boundaries between significant transmission interfaces and points of interconnection with other jurisdictions. Limits for the interfaces and interconnections are also included in Figure 5.2. To assist in understanding the analytical evaluations of the transmission system, Figure 5.3 provides a simplified depiction of Figures 5.1 and 5.2. The characteristics of the transmission zones, transfer interfaces and interconnections are detailed in Appendix D.

Table 5.1 shows the total operable generation capacity by resource type and the forecasted 2002 normal weather, winter coincident peak demand for each zone. The total generation identified in the table differs from the total installed generation provided in Section 3 by an amount equivalent to three Pickering A units, since these units are not forecast to be returned to service before the 2002 winter peak.

5.2 Power Transmission Flows across Major Interfaces and Interconnections

5.2.1 Major interfaces

The total power flow across major interfaces will vary from time to time during any given period, depending on the generation dispatch and demand requirements in each zone.

To illustrate past performance, the distribution of power flows for 2000 across most major transmission interfaces is shown in Appendix D, Figures D1.2.1 and D1.2.2. Power flows for the Flow Away from Bruce Complex (FABC) are not shown because they generally did not change unless there was an outage to a Bruce B unit.

Table 5.1 Winter 2002 – Generation and Demand by Transmission Zone

Zone Name	Resource Type & Output of Units MW					Total Operable Generation MW	Forecast Winter Peak Demand MW
	Hydro	Nuclear	Oil & Gas	Coal	Other		
Northwest	675	0	183	517	6	1,381	1,003
Northeast	2,142	0	514	0	11	2,667	1,694
East	1,984	3,524	2,532	0	0	8,040	4,529
Essa	430	0	0	0	0	430	1,333
Toronto	0	2,579	172	1,148	15	3,914	7,739
Niagara	2,197	0	0	0	0	2,197	860
Bruce	0	3,140	0	0	1	3,141	122
Southwest	0	0	9	3,920	4	3,933	4,088
West	0	0	296	1,948	0	2,244	2,363
Totals MW	7,428	9,243	3,706	7,533	37	27,947	23,731

5.2.2 Interconnections

As shown in Figure 5.2, the Ontario transmission system is interconnected with Manitoba, Quebec, Minnesota, Michigan and New York. The IMO coordinates with the adjacent control areas to dispatch power imports and exports in and out of Ontario over interconnections. The coincident Ontario export and import capabilities are not the arithmetic sum of the individual interconnection flow limits. At best, the interconnections can carry coincident exports of up to approximately 5,800 MW and coincident imports of up to approximately 3,900 MW. The coincident export/import capabilities can be limited due to transfer limitations internal to Ontario and because of the combined transfer capability of the interconnections between Michigan/New York and Ontario.

Internal transfer limitations such as Queenston Flow West (QFW) interface limit can prevent more than about 1,000 MW from being imported at New York-Niagara. Reduction of Beck generation in the Niagara zone can alleviate the internal transfer limitation imposed by the QFW interface. The transfer capability eastwards across the interface comprised of 230 kV circuits N21W, N22W, L24L, L26L, W45LC and W45LC can prevent more than 1,000 MW from being imported at Michigan with four Lambton units in-service. Reduction of Lambton generation can alleviate the internal transfer limitation imposed by this interface. Exports are usually not limited by internal transfer limitations.

The Michigan/New York by Ontario transfer capabilities are determined by parallel path flows and the distribution of demand and generation across the interconnections. At most, the total transfer could be the sum of the two interconnection flow limits. However, due to parallel path flows, the total transfer is usually less than the sum of the two interconnection flow limits. The problem of parallel path flows occurs when the flow on one interconnection reaches its limit. This then causes the flow on the other interconnection to be stuck at its current flow because an increase in this flow will cause the flow on the first interconnection to exceed its limit. Parallel path flows can cause the total transfer to be the minimum of either the New York or Michigan interconnection flow limit. As a result, the Michigan/New York by Ontario transfers can range from approximately 1,000 MW to 2,400 MW under import conditions, and from approximately 2,400 MW to 4,850 MW under export conditions.

As detailed in Appendix D, section D1.4, when the Ontario – Michigan phase shifters go into service, the phase shifters will be able to control up to about 600 MW of Lake Erie Circulation (LEC). Control of LEC to levels less than 600 MW should allow scheduled power flows to be maintained at the Ontario – Michigan interconnection. With scheduled power flows maintained on the Ontario – Michigan interconnection, the combined Michigan/New York by Ontario transfer capability will be less affected by parallel path flows. This will provide more opportunities for coincident Ontario exports and imports of 5,800 MW and 3,900 MW.

If the LEC levels exceed the capability of the Ontario – Michigan phase shifters to maintain full control of the flows on the Ontario– Michigan interconnection, the coincident Ontario export and import capabilities will then be determined by the Ontario – Michigan and Ontario – New York transfer capabilities as previously explained.

Historically, the combined New York and Michigan exports and imports have usually been below 2,000 MW. High levels of power transfer to and from New York and Michigan have occurred in some unusual instances where the various supplying systems provided support under system emergency operating conditions. For the Manitoba, Quebec and Minnesota interconnections, the exports and imports have usually been at their specified flow limits.

The individual interconnection flow limits, for all elements in-service, are shown in Appendix D, Table D3.1.

5.3 Proposed New Transmission and Generation Projects

All proposed new generation and transmission projects that will be connected to the IMO-controlled grid must be assessed via the IMO Connection Assessment and Approval (CAA) process, pursuant to Market Rules, Chapter 4, Section 6.

At this time, the only major transmission project is a new 1,250 MW High Voltage Direct Current (HVDC) interconnection with Quebec, near Ottawa. This HVDC interconnection is to be built by Hydro One and Hydro Quebec. Pending regulatory approvals, the probable in-service date is May 2003.

There is also a proposal by TransEnergie US to construct a 990 MW HVDC interconnection, which would start at the Nanticoke Thermal Generating Station and then cross Lake Erie. The expected in-service date of this project is the second quarter of 2004.

Proposals for new generation are detailed in Section 3.3, Table 3.2.

Figure 5.1 Ontario's Internal Transmission Zones

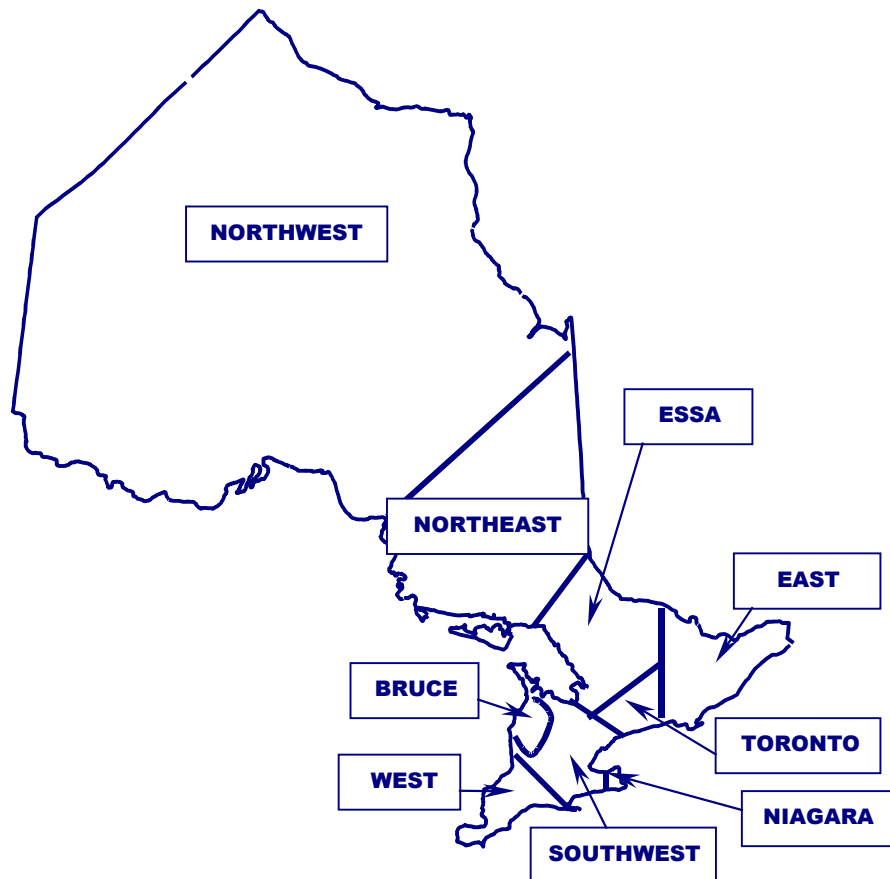
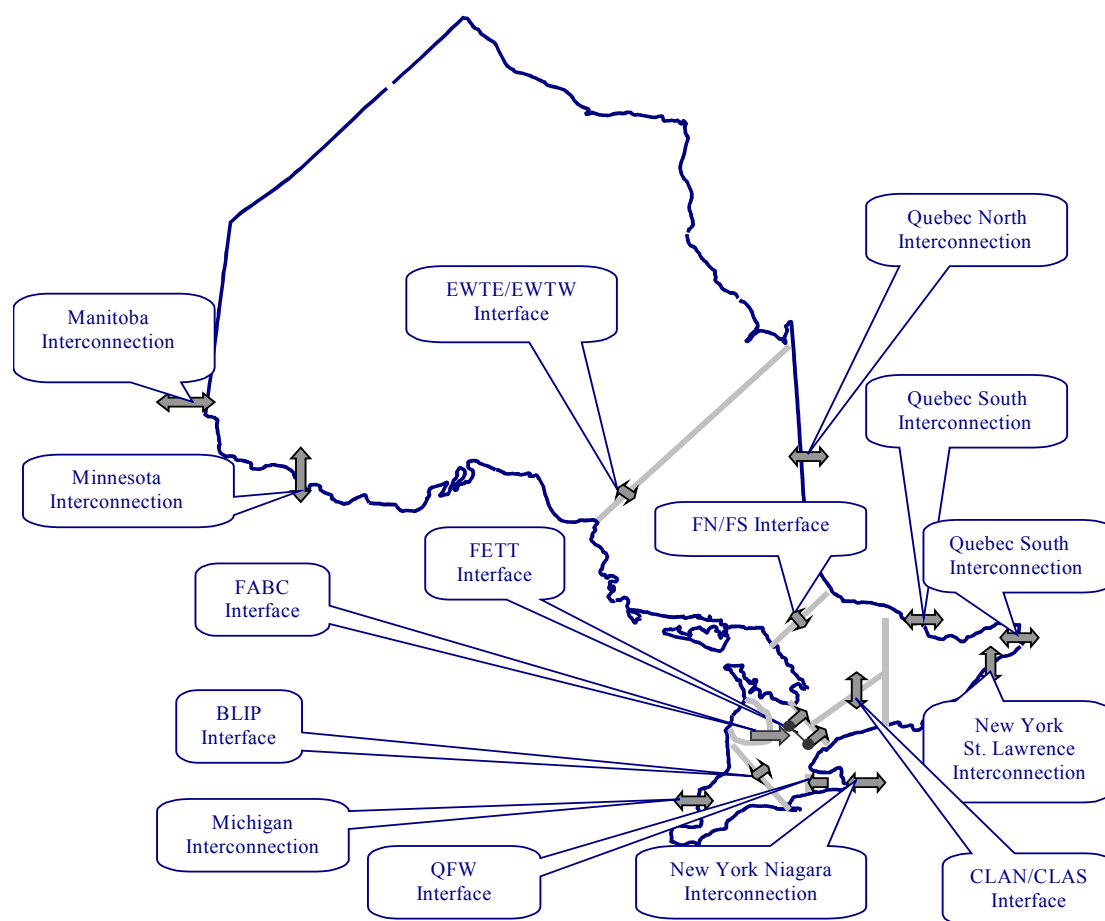


Figure 5.2 Ontario's Significant Internal Transfer Interfaces and Points of Interconnection With Neighbouring Areas**Interconnection****Manitoba****Minnesota****Quebec North****Quebec South****New York Niagara (60 Hz and 25 Hz)****New York St. Lawrence****Michigan****Transmission Transfer Interface****East-West Tie East (EWTE)****East-West Tie West (EWTW)****Flow North (FN)****Flow South (FS)****Claireville North (CLAN)****Claireville South (CLAS)****Flow Away From the Bruce Complex (FABC)****Buchanan Longwood Input (BLIP)****Negative BLIP (NBLIP)****Queenston Flow West (QFW)****Flow East to Toronto (FETT)****Flow Limit in MW**

Before January 30, 2002: 218 in, 163 out Summer / 259 in, 190 out Winter

After January 30, 2002: 343 in, 288 out Summer / 369 in, 300 out Winter

100 in, 150 out

64 in, 80 out Summer / 78 in, 80 out Winter

1,328 in, 432 out Summer / 1,328 in, 452 out Winter

1,400 in, 2,100 out Summer / 1,650 in, 2,100 out Winter

400 in, 400 out

1,650 in, 2,450 out Summer / 1,750 in, 2,700 out Winter

Base Limit in MW

325

350

1,900

1,400

2,000

1,000

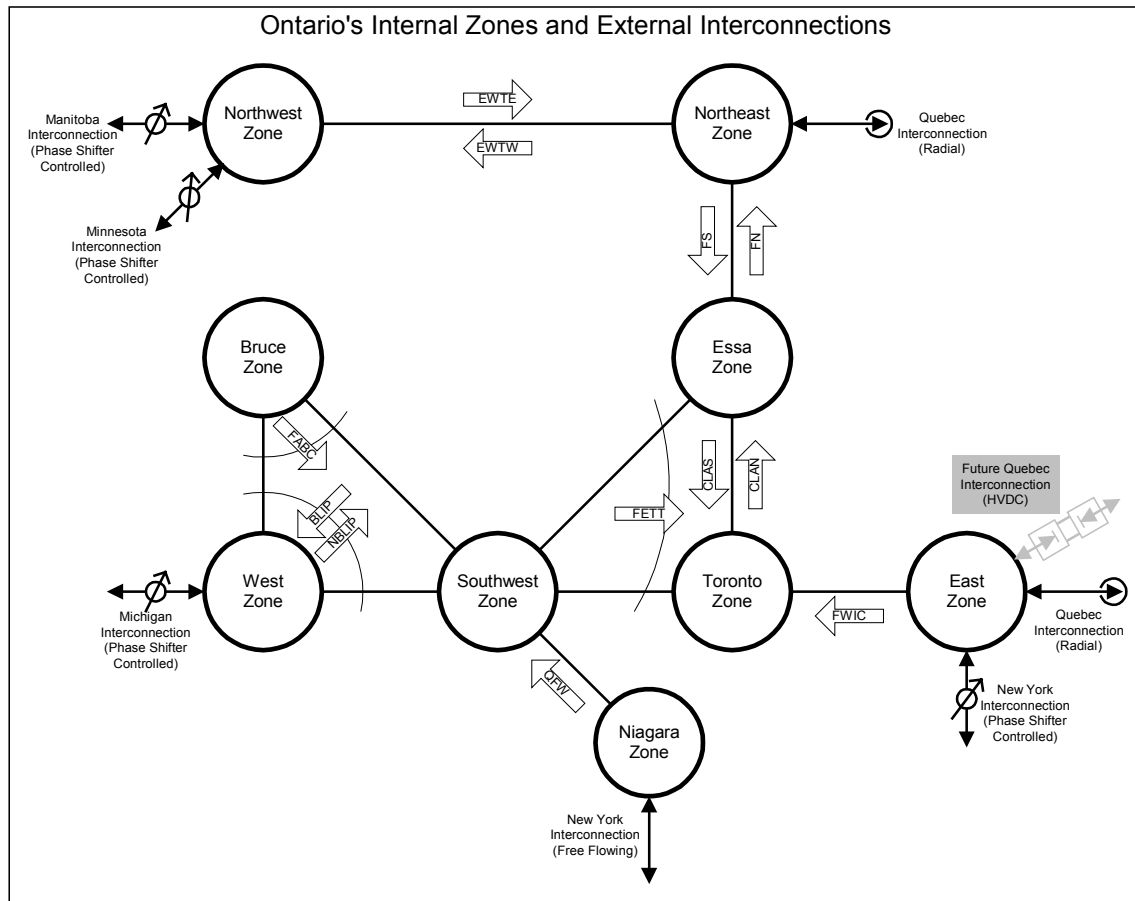
5,200, normally not limiting

3,500

1,500

1,800 Summer / 2,030 Winter

5,700; 5,500 Summer if Ontario Demand (OD) between 22,001 and 22,600 MW; 5,300 Summer if OD between 22,600 and 25,000 MW

Figure 5.3 Ontario's Internal Zones and Interconnections

6.0 Transmission Adequacy Assessment

6.1 Introduction

Transmission adequacy assessment is based on the need to ensure that sufficient transmission capability is available to deliver power to demands in conformance with NPCC or other applicable system security criteria and assuming the continued use of Special Protection Systems such as generation rejection and load rejection.

The principal purpose of the transmission adequacy assessment is to identify any areas where supply reliability may potentially be at risk and to identify investment opportunities to improve system operating efficiency or market efficiency. This could be due to a combination of factors such as load growth or reduction of generation capability within a certain area or the inability of generation which is located within adjacent transmission zones to provide the required level of support to the area due to transmission system limitations. The scope of this assessment is described in Section 6.2, where the areas studied have been limited to the nine transmission zones depicted in Figure 5.3.

Another purpose of the transmission adequacy assessment is to identify transmission interfaces that have the potential to become congested and thus reduce market efficiency. This assessment is described in Section 6.3.

Section 6.4 discusses potential reliability concerns within the transmission zones. In addition, results of load flow studies for 2002, 2006 and 2011 are presented to identify potential voltage problems and risk of violations of existing operating security limits. Some of the 2006 and 2011 load studies included scenarios with the proposed 1,250 MW HVDC interconnection with Quebec.

Transmission adequacy can be assessed assuming various resource availability scenarios. The assessments made in Sections 6.2, 6.3 and 6.4 assume that the resources available include the existing operable generation and new generation projects that have a CAA System Impact Assessment (SIA) completed or in progress. Inclusion of these generation projects is consistent with Resource Scenario #2 described in Section 3.4. Table 3.2, in Section 3.3, lists these projects with a CAA status of SIA. The recent news regarding the restart of two Bruce A units by the summer of 2003 and the proposal that Lakeview Thermal Generating Station cease burning coal beyond April 2005 have not been included in these assessments.

Since the proposed Lake Erie HVDC interconnection project does not have a CAA System Impact Assessment (SIA) completed or in progress, the project was not included in any of the transmission adequacy assessments.

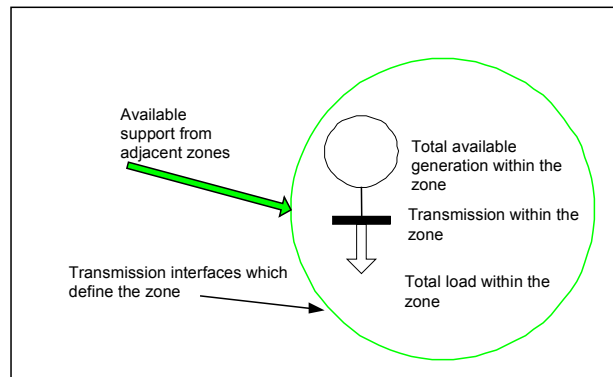
Section 6.0 does not address the adequacy of the 115 kV transmission supply in the IMO-controlled grid, nor does it address the adequacy of transmission supply to local areas such as Windsor or Ottawa. The absence of these assessments in this outlook does not imply that deficiencies in these areas do not exist. Future 10-Year Outlooks will assess the adequacy of these areas. Further details on the impact of new generation and transmission projects are discussed in Section 6.5 and the overall conclusions of the transmission adequacy assessment are summarized in Section 6.6.

6.2 Reliability Assessment of Transmission Zones

6.2.1 Methodology and Assumptions

The assessment of reliability within each transmission zone is based on the conceptual model shown in Figure 6.1.

Figure 6.1 Conceptual Reliability Model of a Transmission Zone



Several assumptions were made, in using the model, to assess the reliability of supply to the various transmission zones. These assumptions represent conditions that were used, in the past, in the design of the Ontario Hydro transmission system and in the design of supply to local load areas. Because these assumptions are intended to represent the transmission system under stress, they often have a low probability of occurrence and do not usually represent typical conditions. Nevertheless, these assumptions are considered appropriate for purposes of assessing the reliability of the transmission system because stress conditions do occur from time to time.

The total available generation within the zone was assumed to be that amount of generation expected to be available if the two largest generating units within the zone were unavailable. All available generation was assumed to be operating at installed capacity. For the Northeast zone analysis, winter nighttime conditions were represented by assuming that no hydroelectric generation was available, since current operating practice is to operate the hydroelectric generation output at a minimum and the need for support from outside the zone is the highest at off-peak times. A combined analysis of the Northwest and Northeast zones during winter nighttime conditions was also completed.

Since local transmission interface limits within a zone were ignored, the transmission system within the zone was assumed to be adequate to supply all demands within the zone. Also any generation within a zone was assumed to be available at zone interface(s).

Using the Median Growth, Extreme Weather scenario, the non-coincident peak demand for each transmission zone was used in this assessment. For the winter nighttime scenarios, the demand values were scaled down to represent off-peak conditions.

The available support from adjacent zones was determined as follows. For the zone being studied, available generation and demand within the zone were set at the levels described above and the amount of generation surplus or deficiency for each zone was calculated. Surplus

generation within zones was then “transported” to deficient zones, to the extent possible, while respecting the operating security limits associated with the interfaces that define zonal boundaries, as described in Appendix D, Section 2. The summer limit for the Queenston Flow West (QFW) interface was used in the assessment because it is more restrictive than the winter limit for this interface. The FETT interface limit was derived on the assumption of summer conditions, and varies according to the number of Nanticoke units and large generating units east of FETT that are in-service. The remaining interface limits are independent of summer and winter conditions.

6.2.2 Results of Reliability Assessment – Power Supply to Zones

For the period 2002 to 2011, the Bruce, Niagara and East transmission zones show a local generation surplus requiring no transfers from adjacent zones. The Southwest, Toronto and Essa zones show a local generation deficit requiring transfers in from the adjacent zones under the postulated local conditions described in Section 6.2.1. With no local hydroelectric generation, the Northeast zone nighttime assessments show a generation deficit requiring transfers from adjacent zones. In all these cases, there is sufficient transmission capacity available to carry the required transfers into the generation deficient zones.

The local deficit situation in the Toronto zone is most significant in 2002. For the 2002 Toronto zone assessment, one Pickering A unit was assumed back in-service. The local deficiency is reduced significantly for 2003 to 2011 if all Pickering A units return to service and if all the proposed Sthe generation projects are incorporated. Even if the two Sthe projects do not materialize and the Pickering A units are in-service, generation from adjacent zones is available to cover the generation deficit in the Toronto zone. For the Southwest and Essa zones where no new generation facilities are proposed into the reliability assessments, the largest local generation deficit occurs in 2011.

For 2002 and 2003, the West zone is able to receive transfers from adjacent zones to cover the generation deficits via the transmission system. For 2004 to 2011, with the incorporation of the four Windsor-Sarnia generation projects, there is a local surplus of generation. Even if the four Windsor-Sarnia projects do not materialize, there is sufficient transmission capacity in 2011 from adjacent zones to supply generation to this zone.

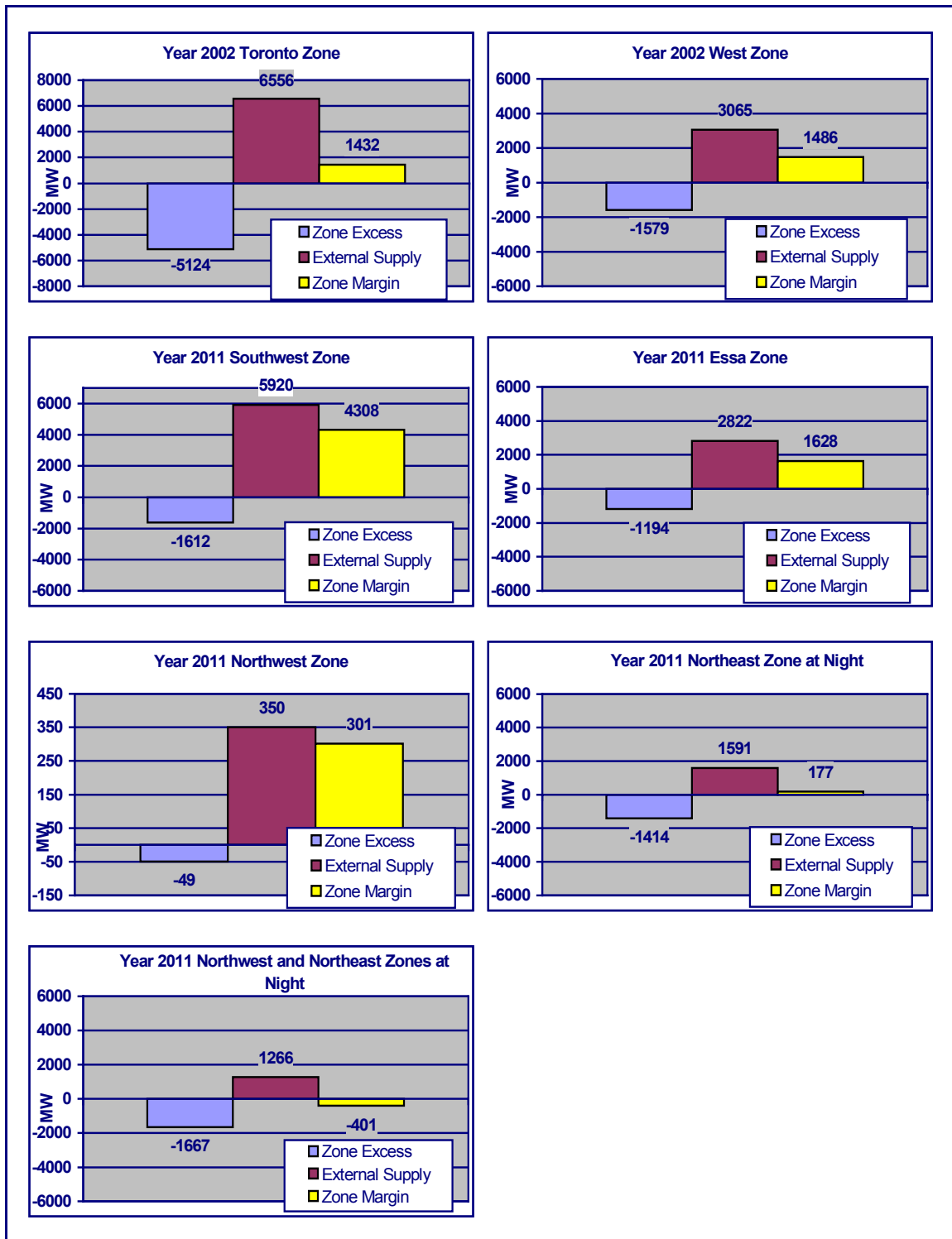
For 2003 to 2011, the Northwest zone shows a local generation deficit requiring a transfer from the Northeast zone or an external market supply. With no new generation proposed in this zone, the largest local generation deficit is in 2011. In all cases, the East – West interface is capable of supplying the required transfers from the Northeast zone to the Northwest zone.

For 2002 and 2003, the combined Northwest and Northeast nighttime assessment shows a local generation deficit even with the Firm purchase of 200 MW from Manitoba. However, there is sufficient transmission capacity available to carry the required transfers from the south. For 2004 to 2011, with no Manitoba Firm purchase, there is a generation deficit that cannot be entirely supplied from adjacent zones in the south. Reinforcement of the transmission system at the CLAN/CLAS interface would alleviate this problem.

The “worst-case” capacity balance in each of the above deficit zones is summarized in Figure 6.2 for the Median Demand Growth, Extreme Weather scenario. The zone excess is the local zone generation and demand balance, with two of the largest units in each zone out of service, except

for the Northwest and Northeast nighttime assessments noted above. The external supply is the lower of the interface transmission capability limit and the excess generation capacity at that time. The zone margin is the difference between the external supply and the zone excess.

Based on the results of the reliability assessments, it is concluded that the capability of the transmission system is adequate to supply the demands within each of the nine transmission zones for the period 2002 to 2011.

Figure 6.2 Reliability Study – Median Demand Growth, Extreme Weather Scenario

6.3 Congestion Assessment

Transmission flows are determined by the pattern of loads and generation, and the characteristics of the transmission system at any given time. Each of these factors is inherently somewhat unpredictable due to the effect of random forced outages on generation and transmission facilities and the effect of weather on load levels. With the opening of the Ontario Electricity Market, an additional level of uncertainty is added because bid and offer prices, rather than traditional economic dispatch principles, will determine the dispatch of generation. Without any history of market operation, congestion on the Ontario transmission system is very difficult to forecast with any degree of accuracy. Hence, rather than attempting to forecast congestion, an approach has been developed to identify the conditions under which congestion is likely to occur on the major transmission system interfaces. If additional generation is added to appropriate points on the system in future years, the level of system flows would generally be expected to reduce and congestion would tend to be relieved. Conversely, if too much generation is added to a transmission zone, it could increase the level of system flows on the connecting transmission transfer interface, thereby, creating congestion. The incorporation of additional transmission capacity on the interface would alleviate this problem.

6.3.1 Methodology and Assumptions

The following approach was used to identify conditions under which congestion is likely to occur. It tests the flexibility of various transmission interfaces to transfer power for generators who want to maximize their generation output in response to market prices.

The system was “stressed” separately from the north, west and east relative to the load center in the Toronto zone, which is generally deficient in generation.

In each scenario studied, demand levels were set at 80% of the winter peak demand levels from the Median Demand Growth, Normal Weather scenario to reflect an off-peak demand level which represents typical congestion circumstances. For each year and scenario studied, the total operable generation in each transmission zone was used, as detailed in Table 5.1, plus the remaining three Pickering A units and any expected new generation with a SIA completed or in progress.

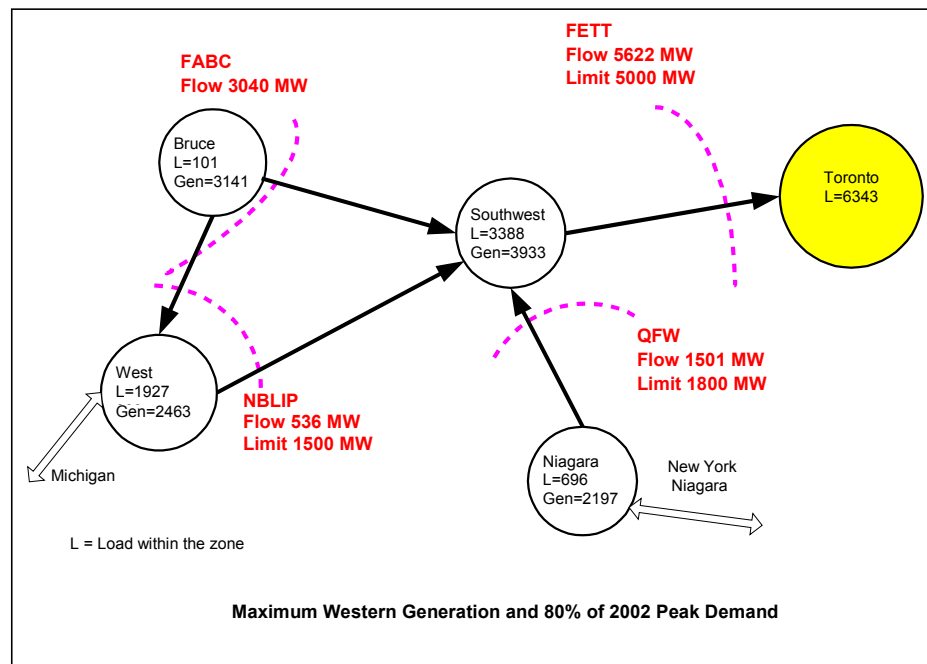
All the calculations were made under the assumption that Ontario’s internal generation will be made available to the Ontario Electricity Market. However, the Ontario Market Rules do not preclude generators from selling to points outside of Ontario.

Base limits, assuming all elements in-service, were used for assessing congestion on the transmission interfaces. In most cases, interface limits are independent of summer and winter conditions, but there are some exceptions. For the Queenston Flow West (QFW) interface, the summer limit was used because it is more restrictive than the winter limit associated with this interface. For the Flow East to Toronto (FETT) interface, the limit was penalized using summer penalties because they are more restrictive than in the winter. Starting at a FETT limit of 5,700 MW, the limit was reduced by 300 MW for having Darlington units G1 and G3 in-service and 400 MW for having a primary demand greater than 22,601 MW. Local transmission interface limits within a zone were ignored. These local limits could reduce the actual amount of generation available at the zone interface(s).

6.3.2 System Stressed from West of Toronto

The conditions in this scenario are displayed in Figure 6.3 for 2002. Power is supplied from the Bruce, Niagara and West zones towards Toronto stressing the Flow East into Toronto (FETT) interface. Since the available flow on this interface is above the FETT limit, there is 622 MW of constrained generation.

Figure 6.3 Congestion Test – West of Toronto



Under this study scenario, no power can be imported from the USA at New York-Niagara and/or from Michigan without displacing Ontario generation since the FETT interface is already congested. A power import of 960 MW via the Michigan interconnection would result in congestion on the Negative Buchanan Longwood Input (NBLIP) interface out of the West zone.

The study did not consider the impact of Lake Erie Circulation (LEC). The flow (not shown) circulates through Ontario, normally in at New York-Niagara and out at Michigan, and can be controlled within required limits. LEC would add to any flow on the Queenston Flow West (QFW) interface, but would reduce the flow on the NBLIP interface. It is anticipated that this circulating flow will be well controlled through appropriate use of the Ontario – Michigan phase shifters once they are placed in-service.

The study scenario was repeated for 2003 to 2011. Particular attention was paid to new Windsor-Sarnia generation facilities proposed for the West zone. Figures 6.4 and 6.5 show the potential congestion on the NBLIP and FETT transmission interfaces, respectively, assuming existing operating limits on the interfaces. In summary, congestion is likely to occur on the NBLIP interface with the proposed Windsor-Sarnia generation facilities. Congestion on the FETT interface increases. During import conditions and high generation levels southwest of

Toronto, congestion is also likely to occur. Congestion on the NBLIP and FETT interfaces may be relieved by adding transmission capacity.

Figure 6.4 Potential Congestion on NBLIP Interface – 2002 to 2011

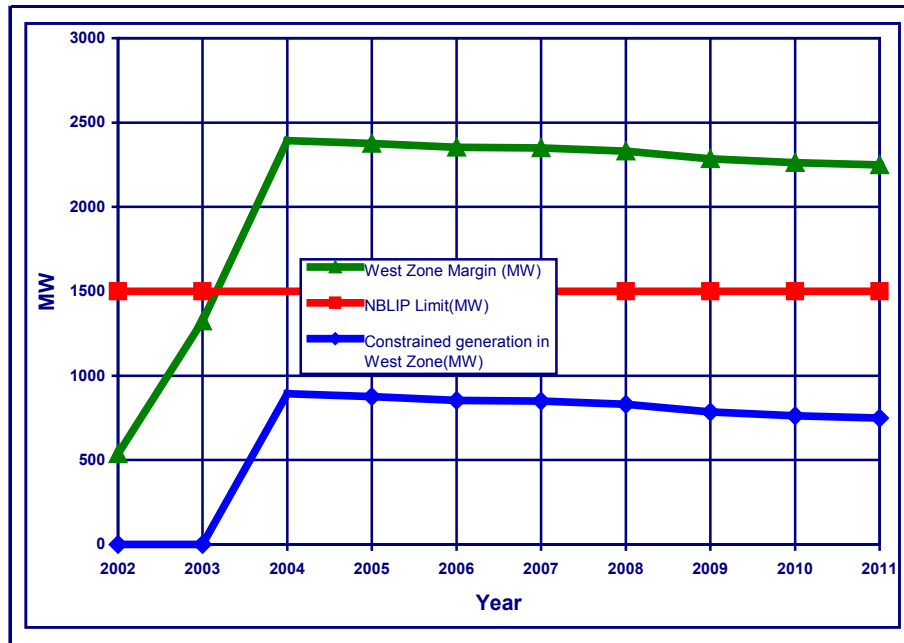
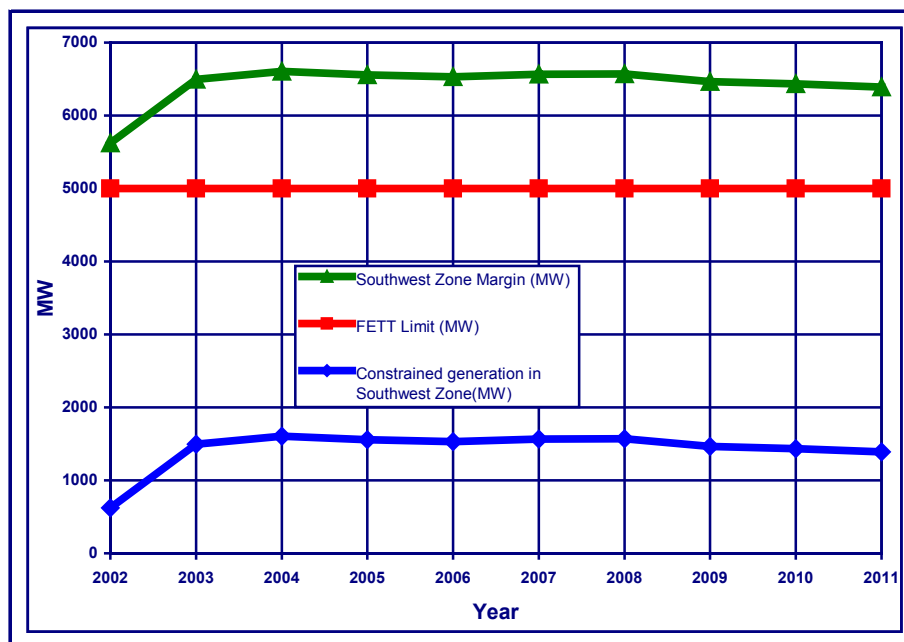


Figure 6.5 Potential Congestion on FETT Interface – 2002 to 2011

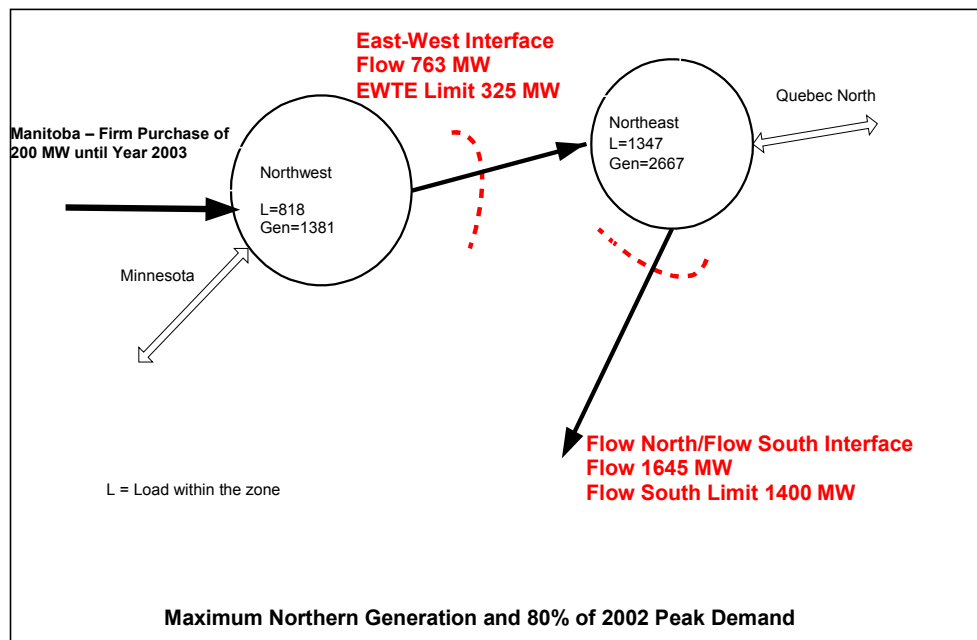


6.3.3 System Stressed from North of Toronto

The conditions in this scenario are shown in Figure 6.6 for 2002. The Minnesota and Quebec-North imports are assumed to be zero. With a Manitoba import of 200 MW and assuming generation in the Northwest of 1,381 MW, there is 763 MW of excess generation in the Northwest, of which only 325 MW can flow to the east system, leaving 438 MW of excess power in the Northwest zone. Under these specific conditions, congestion occurs on the East – West (EW) interface.

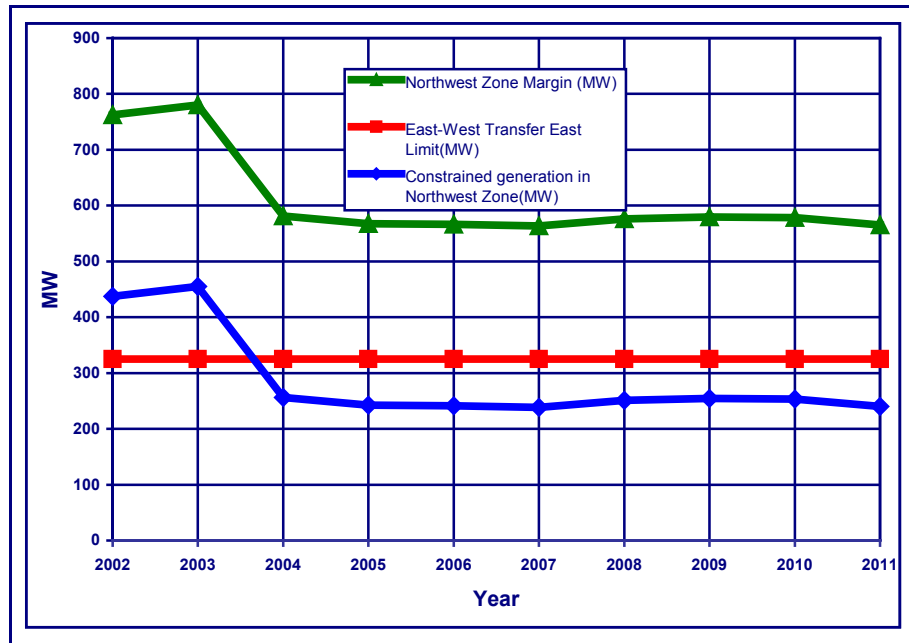
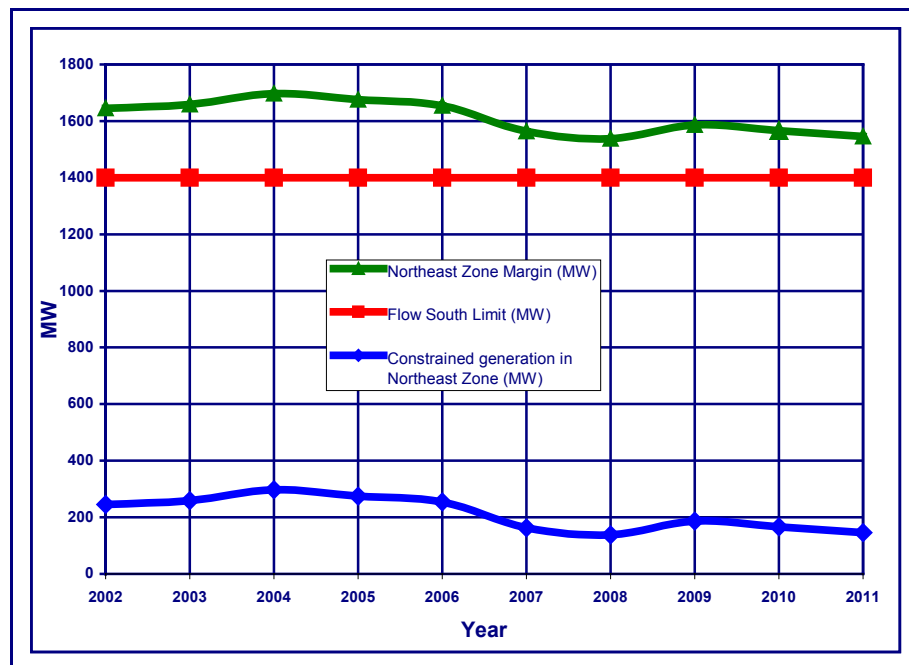
The East – West flow towards the east of 325 MW adds to the Northeast zone excess. As a result, 1,645 MW are available to flow south on the Flow North/Flow South (FN/FS) interface. Since this available flow exceeds the Flow South limit of 1,400 MW, there is 245 MW of constrained generation in the Northeast zone.

Figure 6.6 Congestion Test – North of Toronto



The study scenario was repeated for 2003 to 2011 with the inclusion of the proposed Northland Power generation addition to Kirkland Lake Generating Station (GS). In all cases, congestion is likely to occur on the EW and the FN/FS interfaces as shown in Figures 6.7 and Figures 6.8, respectively. Even without the proposed generation addition at Kirkland Lake, there is still congestion on the FN/FS interface. High hydraulic generation output at spring freshet, combined with lower Northeast demand levels and imports from Quebec, can also result in congestion on the Flow North/Flow South interface.

To alleviate congestion on the EW interface, power may be directed towards Manitoba and Minnesota, depending upon the prevailing prices. Congestion may also be relieved by adding transmission circuits to the EW interface. For the FN/FS interface, congestion may be relieved by adding transmission circuits to the interface.

Figure 6.7 Potential Congestion on EW Interface – 2002 to 2011**Figure 6.8 Potential Congestion on FN/FS Interface – 2002 to 2011**

6.3.4 System Stressed from East of Toronto

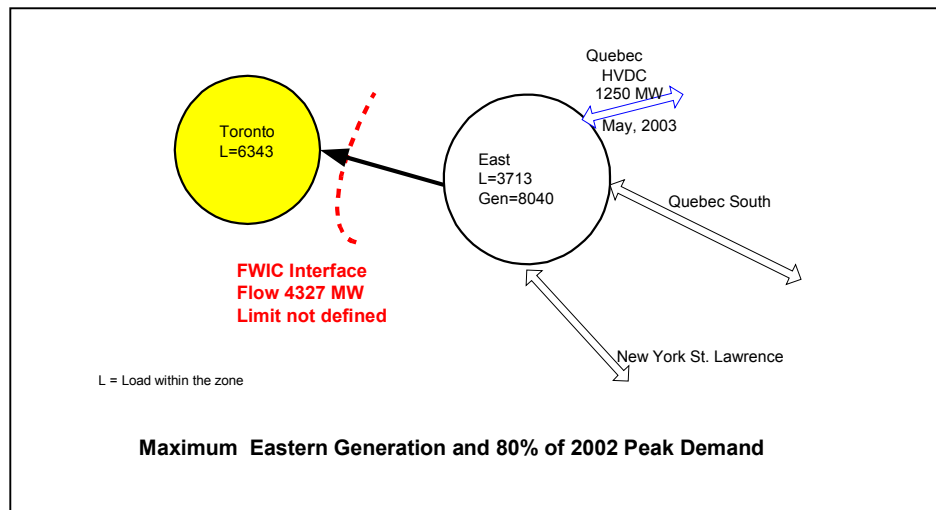
As shown in Figure 6.9 for 2002, an East zone excess of 4,327 MW flows on the Flow West Into Cherrywood (FWIC) interface. The Quebec-South and New York-St. Lawrence imports are

assumed to be zero. No operating security limits have been defined for the FWIC interface, as the expected levels of flow on this interface do not cause congestion.

The study scenario was repeated for 2003 to 2011. For the same reasons cited for the 2002 study, congestion is not expected to be a concern.

Maximum imports from Quebec-South, New York-St. Lawrence and the proposed Quebec HVDC interconnection will potentially increase flow on the FWIC interface by up to 2,450 MW whenever there is a local East zone excess of generation. If these increased flows on the FWIC interface develop, the IMO will identify, develop and implement appropriate operating limits for such transfers.

Figure 6.9 Congestion Test – East of Toronto



6.4 Potential Transmission System Concerns

There are a number of concerns relating to the transmission system that could affect the reliability and efficiency of the market.

In some zones, for example Bruce and Northeast, Special Protection Systems such as generation and load rejection are used to compensate for the lack of sufficient transmission circuits, thereby, minimizing congestion and improving transfer capabilities.

In the Northwest and Northeast zones and other local areas such as Windsor, instability or overloads will not have a significant adverse impact outside of its local zone/area, and less restrictive security criteria are used in design and operation of these zones and areas. As a result, the associated network of transmission circuits in these zones and areas is considered less robust than the associated network of transmissions circuits found in other zones of the IMO-controlled grid.

There are also some potential power system reliability concerns relating to system conditions within various transmission zones. In the Northwest zone, operation of Thunder Bay GS units may be required for control of customer voltage levels, and operation of Ear Falls and Caribou Falls units may be required for control of local power inflows under some load conditions. In the

Northeast zone during off peak load conditions, operation of generation in the Timmins Area is required during high risk conditions on 500 kV circuit P502X.

During extreme hot and humid weather in the Greater Toronto Area, the load level increases compared to normal weather conditions, due to air conditioning load. The high reactive power consumption associated with this load can give rise to low transmission system voltages. This phenomenon was experienced under hot weather conditions in the summer of 1999, when the 500 kV transmission voltage at the Milton Switching Station approached minimum levels.

Load flow studies for 2002, 2006 and 2011 were carried out to identify potential voltage problems and violations of existing operating security limits for both winter and summer peak demands under the Median Demand Growth, Extreme Weather scenario. In Appendix A, Table A2 lists the Ontario peak demands used in these studies. All transmission facilities were assumed in-service, including the Ontario – Michigan phase shifters. Various resource scenarios were used in the studies; unless otherwise noted in the sections below, the various resource scenarios assumed the following generation was available for the studies: OPGI hydroelectric up to 6,100 MW, NUG up to 1,500 MW, Bruce B – four units, Pickering B – four units, Darlington – four units, Lambton – four units, Nanticoke – eight units, Lakeview – four units and Lennox – four units. General observations on the performance of the transmission system were also noted.

2002 was chosen as a study year to determine the performance of the transmission system in the near term. 2006 was chosen because it is the middle year of the study period and all the proposed generation projects under Resource Scenario #2 would be in-service, along with the Quebec HVDC interconnection. 2011 was chosen because it is the last year of the study period and the demand growth is at its highest level.

6.4.1 Year 2002

Two load flow studies were carried out for the winter 2002 peak demand. In the first study, the existing installed generation was assumed available with no Pickering A units in-service. In the second study, the existing installed generation was assumed available with one Pickering A unit in-service. Both studies showed that demand can be met without violating operating limits on the major transmission interfaces, and that voltages at all critical transmission stations can be maintained within acceptable levels.

In the first study, loadings on the Claireville 500 kV autotransformers were near the continuous load rating of 750 MVA for each autotransformer. Results of the second study showed a reduction in the Claireville autotransformer loadings.

Two load flow studies were carried out for the summer 2002 peak demand. In both studies, about 5,600 MW of OPGI hydroelectric generation was assumed available. In the first study, the existing installed generation was assumed available with one Pickering A unit in-service. No violations of the existing operating limits were noted. Most of the reactive resources available to the IMO-controlled grid were required in-service to maintain voltages within acceptable levels at 500 kV and 230 kV transmission stations throughout Ontario, particularly in the Toronto zone. Depending on the number of Lakeview units in-service, loadings on the Claireville 500 kV autotransformers could exceed their continuous load ratings. Outages to Pickering and/or Lakeview units must be carefully managed to avoid the use of voltage reduction or rotational load shedding to alleviate thermal and voltage concerns.

In the second study, the existing installed generation was assumed available with two Pickering A units in-service. Loadings on the Claireville autotransformers decreased to below their continuous load ratings. The additional reactive power from the second Pickering unit further improved voltage levels within the Toronto zone.

6.4.2 Year 2006

Several load flow studies were carried out for the summer and winter 2006 peak demands. For the 2006 studies, a number of resource scenarios were used. The available resources included the existing installed generation plus the four Pickering A units, the Quebec HVDC interconnection, the proposed four generation projects in the Windsor-Sarnia area, and the proposed Sithe generation projects.

For all studies, no violations of existing operating limits of the major transmission interfaces were noted. In addition, no voltage concerns were noted with the appropriate reactive resources in-service. Loadings on the Claireville 500 kV autotransformers varied inversely with the number of Pickering, Sithe and Lakeview units in-service. As more of these units were put into service, the loadings on the Claireville autotransformers decreased. The Lakeview and Sithe units also mitigated the voltage concerns in the Toronto zone.

A study with an HVDC import of 1,250 MW and minimal generation west of the BLIP interface showed heavy power transfers from eastern Ontario to Claireville 500 kV TS, coincident with heavy transfers on the Flow South and BLIP interfaces. Under these study conditions, reactive support west of the BLIP interface was required to provide voltage support. This study demonstrated that the transmission system is capable of providing generators located east of the Toronto zone with an opportunity to supply points located in the West zone.

A study with an HVDC export of 1,250 MW and West zone generation at levels to maximize transfer on the NBLIP interface showed heavy power transfers on the FETT and Flow South interfaces. Like the HVDC import study, reactive support was required to maintain voltages at acceptable levels at critical transmission stations. This study demonstrated that the transmission system is capable of providing generators located in the West zone with an opportunity to supply points located in Quebec.

Finally, for the 2006 summer and winter peak demands, studies were completed under the scenario where 2,000 MW were exported to Michigan and 1,000 MW were exported to New York via the Niagara and St. Lawrence interconnections. With a zero HVDC import, no concerns were observed on the transmission system. With a 1,250 MW HVDC import, power transfers on the FETT interface towards the west are significantly higher than any historical flows in this direction. Presently, no operating limits have been determined for flows towards the west on the FETT interface since heavy transfers in this direction have not been encountered in the past during peak load conditions. If these forecast conditions develop, the IMO will identify, develop and implement appropriate operating limits for such transfers.

6.4.3 Year 2011

Several studies were also completed for the summer and winter 2011 peak demands. Like the 2006 studies, a number of resource scenarios were used. The available resources for these studies did not change from the 2006 available resources.

For both summer and winter 2011 studies no voltage concerns and no violations of the existing operating limits of the major transmission interfaces were identified. In the summer studies, generation in the Toronto zone consisted of least eight Pickering units, two Lakeview units and 1,100 MW of Sthe generation. In the winter studies, generation in the Toronto zone consisted of least eight Pickering units, one Lakeview unit and 600 MW of Sthe generation. For the various generation combinations studied in the Toronto zone, the loadings on the Claireville autotransformers remained within their continuous ratings.

Studies simulating sales to Michigan and New York with the HVDC import conditions noted in the 2006 studies did not produce any new results.

6.5 Impact of Proposed New Generation and Transmission Projects

The impact to the IMO-controlled grid for projects with a CAA status of SIA is briefly summarized in the following sections. Complete details can be obtained at the IMO web site www.theIMO.com under the “Market Services – Connection Assessment and Approval” web page.

6.5.1 Quebec HVDC interconnection Project

Hydro One Networks plans to build a 1,250 MW High Voltage Direct Current (HVDC) interconnection with Quebec. This interconnection will be connected to the East transmission zone. Two 230 kV circuits are required for this project. The circuits will be approximately 35 kilometers long, starting from the Hawthorne Transformer Station (TS) in Ottawa, running through Gamble Junction and then crossing over the Ottawa River to Outaouais Substation in Quebec. Pending regulatory approvals, the probable in-service date is May 2003.

New facilities will be added at Hawthorne TS to accommodate the new circuits and the expected increase in power flow through the station. The new facilities will also include two new shunt capacitors rated at 200 MVARs each.

At the Outaouais Substation, a back-to-back HVDC converter will be installed by Hydro Quebec. New transmission circuits will also be built by Hydro Quebec to improve the security of supply to Outaouais Area.

The proposed facilities will have no adverse impact on the adequacy or the performance of the transmission system. In fact, the proposed facilities should improve the reliability of the East transmission zone. The Flow Into Ottawa (FIO) transfer limit will increase from 1,900 MW to 3,000 MW.

The HVDC interconnection will affect the transfer capability of the Ontario – New York-St. Lawrence interconnection during conditions of simultaneous maximum imports/exports. Under these conditions the Ontario – New York St. Lawrence interconnection will become thermally overloaded for the loss of the HVDC interconnection. Currently, the transfer limit on the Ontario – New York-St. Lawrence interconnection is based on the loss of one of the companion 230 kV circuits, L33P or L34P. The transfer capability limit of this interface will have to be based on the loss of the HVDC interconnection. If under certain scenarios, the import or the export to New York becomes limited due to the HVDC transaction with Quebec, then the transfer on the HVDC interconnection may have to be restricted. It is expected these operating restrictions required to remove New York transfer limitations will not have a material effect on the utilization

of this interconnection. In addition, if more flexibility is desired in the Ontario–Quebec transfers then Hydro One Networks could consider the addition of the loss of the HVDC interconnection to the Saunders generation rejection scheme.

6.5.2 TransAlta (Sarnia), Enron (Lambton), AES (Leamington) and ATCO (Keith) Generation Projects

These four projects are proposed for incorporation to the West transmission zone.

The TransAlta project in Sarnia will be connected to the existing 230 kV circuits N6S and L23N. New facilities will also be added at Scott Transformer Station (TS) to facilitate the incorporation of this project.

The Enron project in Sarnia will be connected to the transmission system via the Lambton Thermal Generating Station (TGS) switchyard. Two new breakers and one replacement breaker are required at the Lambton TGS switchyard.

The AES project near Leamington will be connected to 230 kV circuits C23Z and C24Z. Enhancements to the Windsor area Overload Protection Scheme (OLPS) will be required to increase its scope of coverage and improve its speed of response. The OLPS is an overcurrent protection scheme that was originally designed to protect against thermal overloading on Keith transformers T11, T12, and circuits Z1E, Z7E, under single element contingency conditions.

The ATCO project in Windsor will be connected to Keith Transformer Station via a new 230 kV and 115 kV circuit. New facilities at Keith will be required to incorporate the new circuits from the ATCO site. As with the AES project, similar enhancements to the Windsor Area OLPS will also be required.

The incorporation of the AES and ATCO projects and associated enhancements to the OLPS will help alleviate overload conditions in the Windsor area. In particular, the addition of 115 kV-connected unit at the ATCO development is expected to alleviate overload conditions on the Keith 230/115 kV autotransformers. The addition of the AES generation is expected to reduce power flows between the Keith TS and Lauzon TS on the 115 kV network. During heavy imports from Michigan with only the ATCO generation online, these power flows could become problematic due to thermal concerns. With or without the incorporation of the AES and ATCO projects, reinforcing the transmission system between Keith TS and Lauzon TS or Sandwich Junction would be expected to alleviate most of the overload conditions in the Windsor area and reduce the deployment of the Windsor Area OLPS.

While the operating limits for the Ontario – Michigan Interface are currently based on double-element contingencies, those for the Windsor area only respect contingencies involving single elements since the area is not NPCC impactive. However, with the incorporation of the ATCO and AES projects there is expected to be an increased reliance on Special Protection Systems to prevent significant adverse impacts to the interconnected bulk power system following double-element contingency conditions. This will need to be reviewed, but should the system security analysis confirm that it is possible to operate the system in the Windsor area to respect double-element contingencies, then changes to the Windsor area Special Protection Systems and/or additional reinforcement of the transmission system could be necessary.

The connection of the TransAlta project into Scott TS is expected to result in the present fault interrupting capability of some 115 kV breakers at Scott being exceeded. Therefore, the IMO requires four of the 115 kV breakers to be replaced with higher rated units, and the removal of the existing 115 kV series connected reactors. In addition, in order to maintain the existing transfer capability across the Sarnia/Windsor to Longwood interface, the 2 km section of 230 kV circuits N21W and N22W between Scott TS and Lucasville Junction must be upgraded before this project is connected.

The subsequent incorporation of two new generating stations that are proposed in Michigan with a combined capacity of 1,270 MW will result in the fault interrupting capability of the 230 kV breakers at Lambton TGS being exceeded. To address this concern, the reconfiguration of the L51D interconnection and 230 kV circuits L25N, L26L, L28C and L29C at the Lambton will be required, to allow the Lambton 230 kV busbar to be operated “split”.

Under import and export conditions from Michigan with the Lambton TGS busbar operated “split” and with the initial 2 km section of circuits N21W and N22W upgraded, the transfer capability of the Ontario – Michigan interconnection should not be adversely affected.

Once the Lambton TGS busbar has been “split” to address fault level concerns, the transfer capability eastwards across the interface comprised of 230 kV circuits N21W, N22W, L24L, L26L, W44LC and W45LC will be limited to 2,815 MW. Under import conditions of 1,500 MW from Michigan, approximately 1,200 MW of generation could be constrained west of this interface with all West zone generators in-service. Reinforcement of the transmission system between Lambton TGS and Longwood TS would be expected to alleviate this problem.

Similarly, with all West zone generators in-service, there could also be significant congestion on NBLIP interface. As detailed in Section 6.3.2, there will be constrained generation in the West zone due to the existing NBLIP limit of 1,500 MW. The amount of constrained generation will be dependent on customer loading in the West zone since import conditions were assumed to be zero. In practice, the amount of congestion would also depend on the Ontario – Michigan import conditions. Under maximum imports from Michigan, generation dispatch within the West zone would be limited. Reinforcement of the transmission system to increase the NBLIP limit would help alleviate this problem.

While there may be restrictions on what generating facilities can be dispatched or on the amount of imports, the presence of additional generating capacity on the system to the west of the BLIP/NBLIP interface is expected to have a beneficial impact by providing reactive support, especially during outage conditions. The generators will also help maintain the BLIP limit at its current level even as demand in the West zone increases. Finally, the proposed projects will also alleviate BLIP restrictions during outages to transmission circuits associated with BLIP/NBLIP interface.

6.5.3 Sithe (Goreway) and Sithe (Southdown) Generation Projects

These two projects are to be incorporated in the Toronto transmission zone.

The proposed Sithe (Goreway) generation project will be connected to existing 230 kV circuits V72R and V73R between Bramalea Transformer Station (TS) and Claireville TS.

The proposed Sithe (Southdown) generation project will be connected to existing 230 kV circuits B15C and B16C between Lorne Park TS and Ford TS.

With both Sithe projects incorporated, the fault interrupting capability of two Claireville 230 kV breakers would be exceeded. To alleviate this deficiency, the IMO has identified various options. The preferred option is to re-terminate the Claireville by Richview section of circuit V72R on to the same Claireville bus position as is currently occupied by circuit V75R. The existing radial section, Bramalea by Claireville, of circuit V72R would remain as currently connected on the Claireville TS busbar.

During high load levels, the Toronto transmission zone will be deficient in generation even with these two projects in-service. As a result, there will be no congestion issues associated with these projects. In addition, these projects are not expected to adversely impact the major transfer interface limits of the system. The Sithe projects will improve the reliability of load supply to the Toronto zone and will mitigate the voltage control concern in the Toronto zone by providing additional reactive power. The projects will also help alleviate the potential overloading problems on the Claireville 500 kV autotransformers as the demand increases. In addition, the projects will also help alleviate transmission restrictions during outages to generation units and/or transmission facilities critical for supply to the Toronto zone.

The addition of further generating capacity or changes in the transmission system configuration near Claireville TS could increase the fault level beyond the capability of the existing equipment at Claireville. If this were to happen, it is expected that it would be necessary to operate with the Claireville 230 kV busbar “split”. Should the proposal to “split” the Claireville busbar be adopted, then some reconfiguration of the existing circuits and the re-termination of the idle 230 kV V75R circuit to Richview would be required to maintain transfer capabilities. However, further detailed engineering may identify other options to address the fault level concerns.

6.5.4 Northland Power (Kirkland Lake) Generation Project

This project is to be incorporated in the Northeast transmission zone.

Northland Power’s proposal is to increase the capacity of the existing Kirkland Lake Generating Station (GS) by adding a sixth generating unit at the site. Three of the five existing units are connected to 115 kV circuit D3K which connects to Kirkland Lake Transformer Station (TS) and Dymond TS. The remaining two units are connected to 115 kV circuit K2. The new generating unit is to be connected to 115 kV circuit D3K via a new transformer.

This proposed generator at Kirkland Lake GS will result in a reduction of the existing system transfer capability under conditions of high flow south on 500 kV circuit P502X, and 115 kV circuits A8K and A9K. Therefore, operating restrictions will be imposed on Kirkland Lake GS. For flows south of 750 MW or higher, the total output of Kirkland Lake GS will be limited to 106 MW to prevent the tripping of D3K for the loss of P502X. For flows south less than 750 MW, generation run back of up to 41 MW will be required at Kirkland Lake GS for the loss of P502X.

Installing a second 115 kV circuit between Kirkland Lake TS and Dymond TS, in parallel with D3K would eliminate the operating restrictions on Kirkland Lake GS.

The project is not expected to adversely impact the East – West Transfer and Flow North/Flow South Transfer interface limits. It is also expected that there will be no congestion issues associated with this project on the Flow North/Flow South Transfer interface.

6.6 Conclusions

Reliable Supply to Zones

The transmission interfaces studied in this outlook are capable of supplying the various transmission zones under the generation and demand scenarios considered.

For the nighttime assessment where no hydroelectric generation was assumed dispatched in the Northwest and Northeast zones, there is a generation deficit that cannot be supplied entirely from the adjacent zones within Ontario. Although the probability of this scenario occurring is low, reinforcement of the transmission system at the CLAN/CLAS interface could alleviate this problem.

In the Toronto transmission zone, any reductions to the reactive capability during summer peak demand conditions may result in voltage levels below minimum required levels. As demand in the Toronto zone increases, the reactive capabilities of this zone must also increase to mitigate any voltage concerns during summer peak demand conditions. Restrictions on the use of any local generation, especially Lakeview or Pickering, would increase the need for additional reactive supply.

Market Efficiency

Conditions of maximum generation in western Ontario are expected to result in congestion on the NBLIP and FETT interfaces. This will limit the dispatch of generation in transmission zones west of Toronto, and limit imports from New York-Niagara and from Michigan. The addition of transmission circuits to the NBLIP and FETT interfaces would reduce the congestion.

Under maximum import conditions from Michigan and with the proposed generation projects in the Windsor/Sarnia area, the dispatch of generation within the West transmission zone would be limited. Reinforcement of the transmission system on the NBLIP interface and between Lambton TGS and Longwood TS would alleviate this problem.

Conditions of maximum generation in Northwest and Northeast are expected to result in congestion on the East – West transfer East and Flow South interfaces. An increase in transmission capacity between the Northwest and the Northeast zones would reduce the congestion.

Reinforcement of the transmission system between Kirkland Lake TS and Dymond TS would eliminate the operating restrictions on Kirkland GS.

System/Operating Efficiency

Reinforcement of the transmission system between Keith TS and Lauzon TS or Sandwich Junction would be expected to alleviate most of the overload conditions in the Windsor area and reduce the deployment of the Windsor Area OLPS.

With both Sithe generation projects incorporated, studies show that the fault interrupting capability of two Claireville 230 kV breakers would be exceeded. To alleviate this problem at

Claireville TS, the preferred IMO option is to re-terminate the Claireville by Richview section of 230 kV circuit V72R on to the position currently occupied by V75R.

The addition of further generating capacity or changes in the transmission system configuration near Claireville TS after the Sithe generation projects are incorporated could increase the fault level beyond the capability of the existing equipment at Claireville. The operation of the Claireville busbar “split” would alleviate these fault level concerns. However, to maintain transfer capabilities at Claireville with the busbar “split”, the reconfiguration of some of the 230 kV circuits and the re-termination of an idle Claireville by Richview 230 kV circuit may also be required.

7.0 Overall Observations, Findings and Conclusions

The NPCC reliability standard, based on an annual Loss of Load Expectation of 1 day in 10 years, is forecast to be met throughout the study period. The resource adequacy assessment for 2002 indicates that resources available to supply the forecast of Ontario demands are adequate to meet the specified reserve margin requirements with only a few exceptions. Suitable alternate resource supply options are assessed to be available in case unforeseen events deplete reserve margins by more than the allowance used in this Outlook. Without the addition of new generation capability, or an equivalent reduction in peak demands, reserves towards the end of the study period may fall below desired levels especially for high demand growth.

The development of price sensitive demand or dispatchable demand by Market Participants would contribute to an easing of resource adequacy concerns in the case of fewer than required generation additions. Similarly, a substantial amount of external supply from neighbouring areas, if attracted through market price signals, should be able to reach the Ontario demand areas via the available interconnection and transmission capacity. Quantities in the range of 2,000 MW or more for either of these options (or a combination thereof) would substantially offset the need for new generation. These alternatives are particularly attractive in the short-term because they require little or no lead-time to establish.

Reserve levels are generally higher in the summer than in the winter, mainly because of the higher peak demands in the winter

Based on current knowledge of participant outage cycles, outages can be scheduled to avoid the peak periods. However, should outage durations grow, as might be required for rehabilitation activities or for installation of emission reduction facilities, the IMO expects increasing pressure to accommodate outages over peak periods. As reserve margins increase, through the addition of resources to the IMO-controlled grid, the ability to accept outages over peak periods will improve.

Proposals for almost 6,000 MW of generation additions have been submitted to the IMO for Connection Assessment and Approval. Under median and high growth scenarios a range of 2,000 to 3,000 MW would need to be built and operated to maintain reserve levels at the reliability standard.

The potential shutdown or fuel substitution of Lakeview Generating Station by 2005 has not been explicitly considered in this assessment. However, sensitivity studies indicate that the need date for additional resources could be advanced from 2009 to as early as 2006 for the median growth demand scenario.

If all generation proposals are built and operated, the amount of generation that is exclusively gas fueled would comprise about 21% of the installed capacity within Ontario by 2005. Another 6% of the installed capacity would be dual-fuelled with gas. The IMO has not studied the adequacy of gas supplies, or the adequacy of the gas supply infrastructure in Ontario. The IMO supports the initiation of, and participation in, a regional study, to be undertaken in the near future, to explore various convergence issues between electricity and gas markets, including questions concerning the availability and firmness of long-term gas supply contracts, pipeline capacity (and contingent risk), and susceptibility of the IMO market to generation capacity reductions at peak

times due to gas arbitrage. This latter concern has emerged this past winter, resulting in curtailment of several hundred MW of capacity over the January peak. Many other jurisdictions are concerned with the gas supply issue, and it has been raised in various forums such as NPCC and NERC.

As a competitive alternative to new and existing generation, the IMO believes price responsive demand management options should be vigorously pursued by Market Participants. Demand management is most frequently viewed from one or more of three perspectives, the first being price responsive demand (dispatchable or self-scheduled) which reacts to market price signals; the second being demand curtailment; and the third being energy conservation. Each of these options can have a role to play in the demand and supply balance of the province. Energy conservation can be implemented individually or collectively, at any time, not only in response to price but for other reasons such as environmental concerns. Demand curtailment relies on a broader-based decision process integrated with appropriate deployment technology; introduction of new measures requires some lead-time for development of the necessary infrastructure. Price responsive demand requires not only the technical infrastructure for conveying price signals and implementing dispatch but also an appropriately structured market. To harvest the fruits of this latter demand option at the individual consumer level will require technological advances as well as full retail access to hourly pricing.

The transmission interfaces studied in this outlook are capable of supplying the various transmission zones under the generation and demand scenarios considered. The adequacy of the 115kV transmission supply in the IMO-controlled grid, and in particular the adequacy of transmission supply to local areas such as Windsor or Ottawa have not been specifically addressed in this Outlook.

A major transmission addition, which will commence service during the forecast period, is a 1,250 MW HVDC interconnection between Ontario and Quebec near Ottawa. This line will improve transfer capabilities between the two provinces. For purposes of this assessment, the line is assumed to be in-service starting in May 2003.

The previously identified Toronto area voltage concern during summer peak periods is not expected to be an issue during the ten year period based on the scheduled return to service of Pickering A generating units and the proposed Sithe resource additions.

Existing congestion is likely to continue on the East – West transmission interface emanating from the Northwest zone when supplying energy to southern Ontario.

If all of the additions of generation in the Sarnia/Windsor area proceed, congestion of up to 2,100 MW can be experienced on the transmission between Longwood and Buchanan at times when Toronto is being supplied from the West.

Appendix A – Electricity Demand Forecast

List of Tables

Table A1 Monthly Zonal Energy Forecast, Normal Weather	55
Table A2 Monthly Zonal 20-Minute Coincident Peak Demand, Normal Weather	59
Table A3 Monthly Zonal 20-Minute Non-Coincident Peak Demand, Normal Weather.....	62

List of Figures

Figure A1 Weather Scenarios – Temperature Humidity Index	53
Figure A2 Economic Scenarios – Ontario Employment Growth	54
Figure A3 Economic Scenarios – Ontario Housing Stock Growth.....	54
Figure A4 Annual Energy Demand – Economic Scenarios (Normal Weather)	58
Figure A5 Summer Peaks, Various Scenarios	65
Figure A6 Winter Peaks, Various Scenarios.....	65

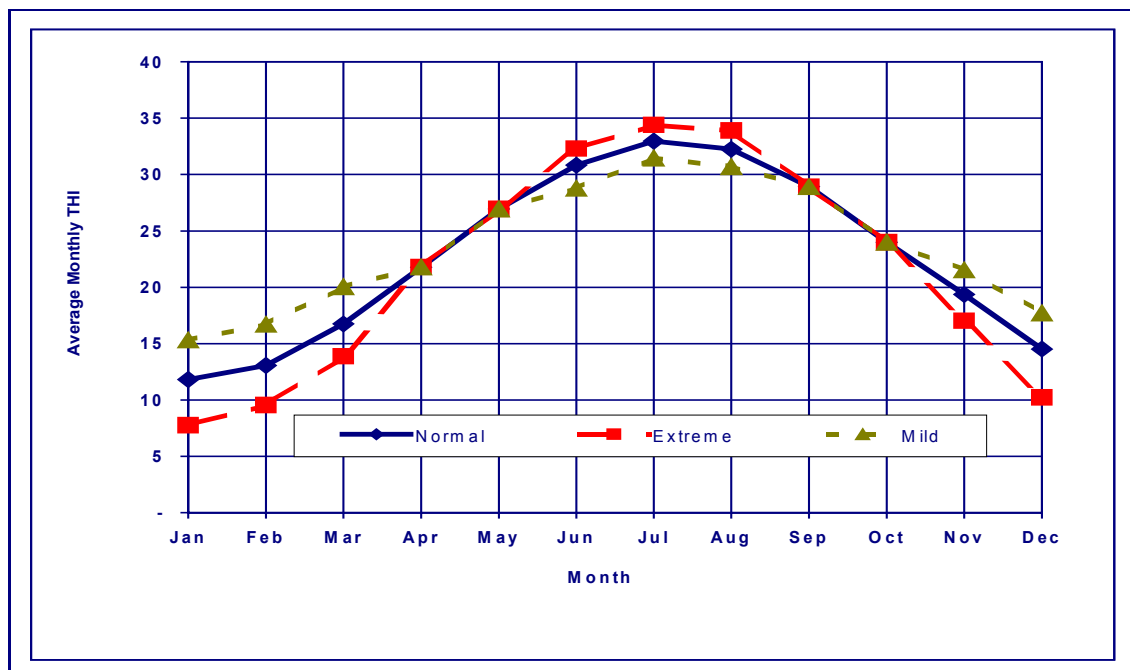
1.0 Normal, Extreme and Mild Weather Scenarios

Normal weather is a construct based on over 30 years of observed daily weather data. For the purposes of the forecast, weekly Normal weather was created. The word weekly denotes the sample size of historical data that one uses. Within each week, the average of the hottest historical days becomes the hottest day in the Normal week, the average of the next hottest historical days becomes next hottest day in the Normal week and so on, until the week's Normal weather is constructed. The daily values are then mapped onto a calendar, in this case 1996, based on the observed sequence of hot and cold days. Once this has been done for all weeks the Normal weather year is complete.

Using Normal weather for the forecast impacts energy demand less so than peak demand. Since recent history has exhibited milder winters and hotter summers, there has been a shift in energy consumption from winter to summer. Using Normal weather re-allocates some energy demand from the summer to the winter, more in line with the traditional weather patterns the system is subject to.

For the purposes of analysis and since Normal weather may not be experienced, two other weather scenarios are also generated. The Extreme weather scenario is generated using the same methodology as the Normal weather, but rather than using the whole 30 year history for each day the sample is restricted to the 5 most extreme observations for each day. Likewise, the Mild weather scenario utilizes the same methodology but restricts the historical sample to the 5 mildest days. Therefore, the Extreme weather scenario would have a colder winter and hotter summer relative to the Normal weather scenario and the Mild weather scenario would have a warmer winter and cooler summer compared to the Normal. Figure 2.1 illustrates the differences in the weather scenarios by comparing the monthly average THI (Temperature Humidity Index). Note that the shoulder months utilize the same values for all scenarios.

Figure A1 Weather Scenarios – Temperature Humidity Index



2.0 Economic Scenarios

As with the weather scenarios, economic scenarios are developed and used in order to gain an understanding of some of the potential outcomes given the fact that there would be a certain degree of uncertainty surrounding the economic forecast. Using three scenarios allows for the assessment of resources and transmission under a variety of potential circumstances. Figures A2 and A3 present the three scenarios.

Figure A2 Economic Scenarios – Ontario Employment Growth

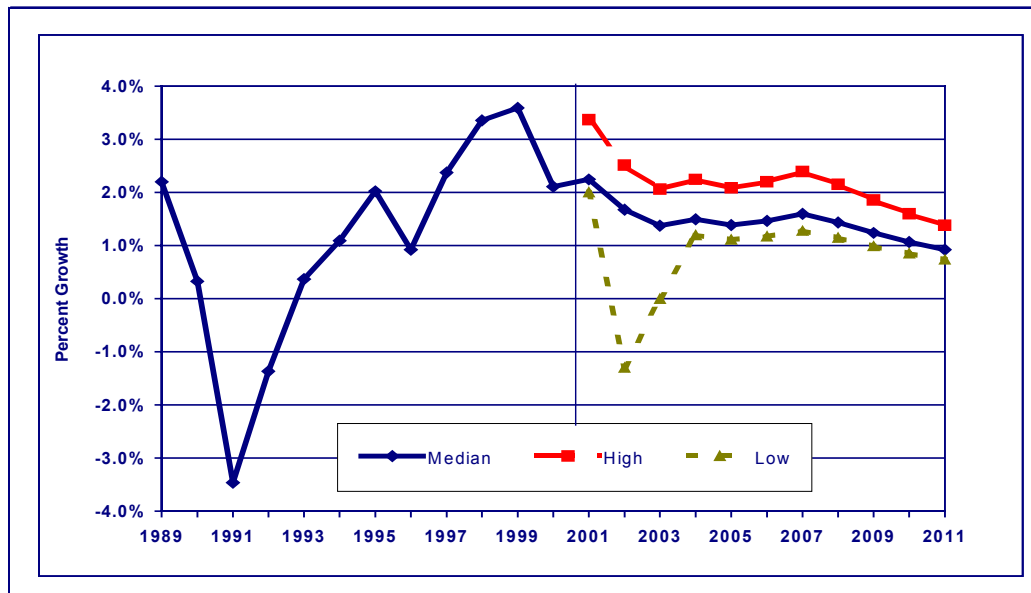
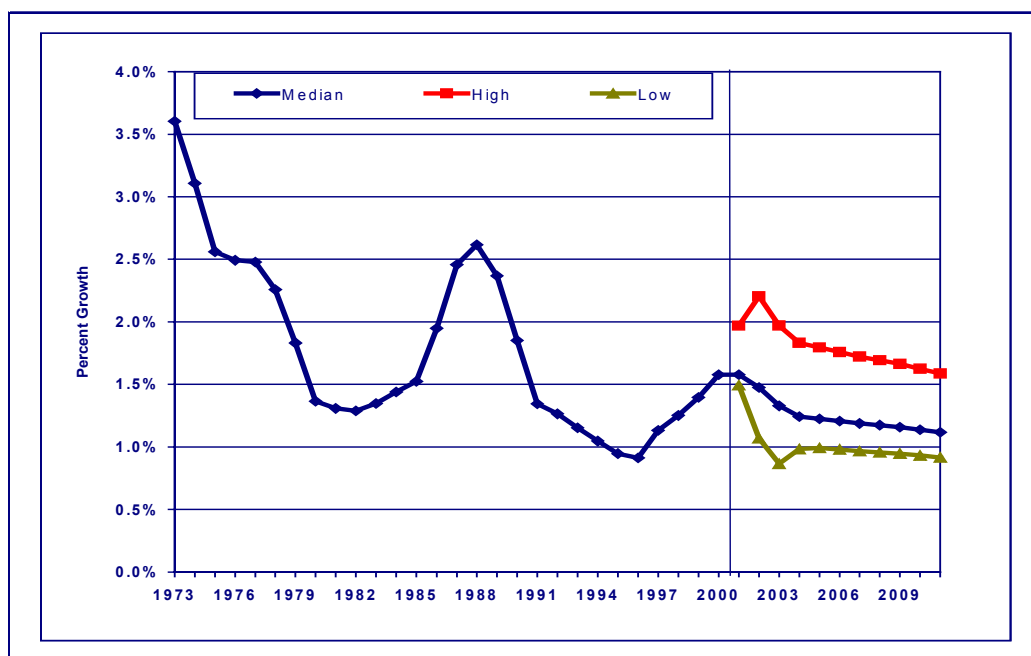


Figure A3 Economic Scenarios – Ontario Housing Stock Growth



3.0 Electricity Energy Demand

Table A1 contains the monthly energy demand by zone under Normal weather. Figure A3 depicts the annual energy forecasts for the three economic scenarios.

Table A1 Monthly Zonal Energy Forecast, Normal Weather

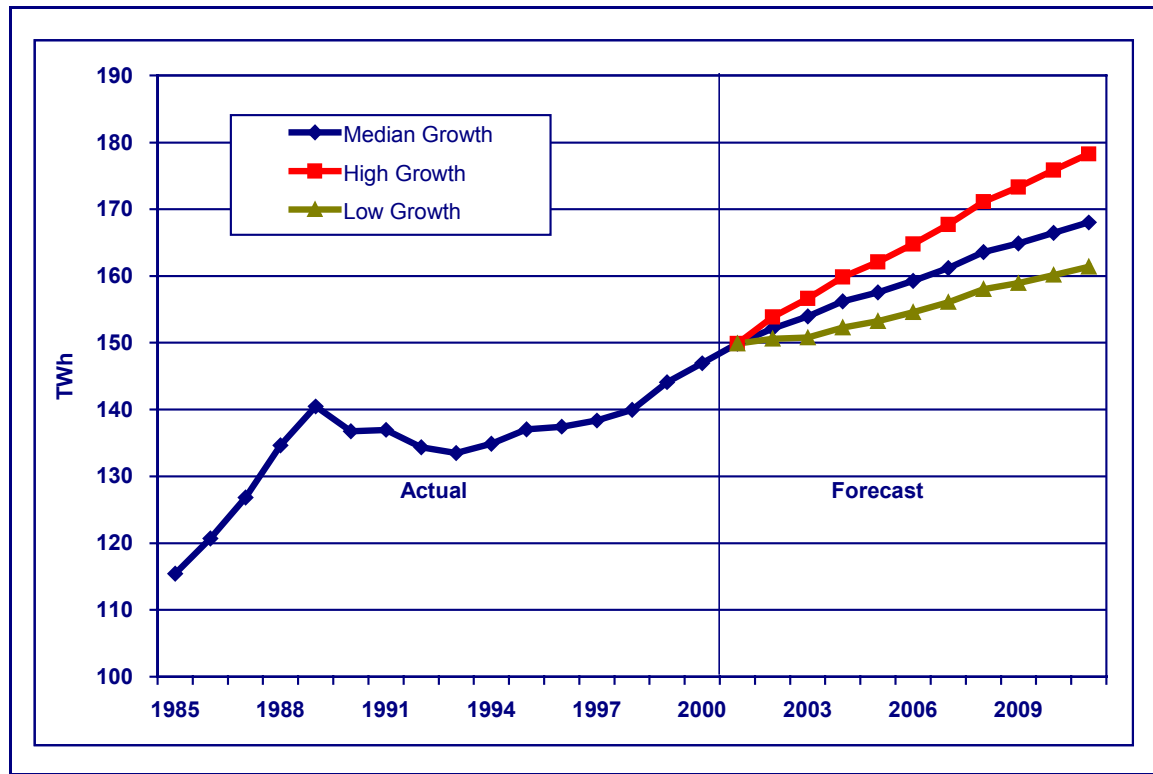
Month	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total
(GWh)										
Jan-02	725	1,194	2,590	762	4,426	550	74	2,459	1,472	14,252
Feb-02	638	1,057	2,284	672	3,902	497	67	2,218	1,306	12,641
Mar-02	675	1,116	2,362	695	4,035	531	69	2,323	1,376	13,182
Apr-02	618	977	2,146	543	3,698	499	65	2,129	1,293	11,968
May-02	612	919	2,107	533	3,630	508	62	2,074	1,342	11,787
Jun-02	593	839	2,137	520	3,610	523	62	2,077	1,461	11,822
Jul-02	585	847	2,377	579	4,015	568	68	2,286	1,626	12,951
Aug-02	624	932	2,311	562	3,903	560	66	2,245	1,577	12,780
Sep-02	596	950	2,108	513	3,561	506	62	2,074	1,394	11,764
Oct-02	662	1,062	2,217	561	3,820	525	64	2,160	1,367	12,438
Nov-02	669	1,088	2,305	583	3,973	521	66	2,230	1,381	12,816
Dec-02	677	1,171	2,480	730	4,237	531	70	2,384	1,434	13,714
Jan-03	728	1,223	2,625	773	4,486	556	74	2,471	1,492	14,428
Feb-03	640	1,086	2,316	682	3,958	503	67	2,231	1,325	12,808
Mar-03	679	1,148	2,408	709	4,114	541	70	2,347	1,403	13,419
Apr-03	621	1,002	2,173	550	3,744	503	63	2,132	1,309	12,097
May-03	615	948	2,133	540	3,676	513	62	2,079	1,356	11,922
Jun-03	594	861	2,174	529	3,672	528	63	2,095	1,482	11,998
Jul-03	584	868	2,407	586	4,066	571	69	2,296	1,642	13,089
Aug-03	622	954	2,328	567	3,933	562	66	2,244	1,586	12,862
Sep-03	595	969	2,145	522	3,624	511	61	2,092	1,414	11,933
Oct-03	662	1,085	2,245	568	3,868	529	65	2,170	1,384	12,576
Nov-03	668	1,112	2,326	589	4,009	524	67	2,232	1,392	12,919
Dec-03	678	1,193	2,519	741	4,304	538	72	2,403	1,456	13,904
Jan-04	729	1,249	2,648	779	4,525	560	73	2,475	1,504	14,542
Feb-04	663	1,144	2,421	713	4,137	524	70	2,315	1,384	13,371
Mar-04	677	1,164	2,449	721	4,185	547	70	2,371	1,426	13,610
Apr-04	623	1,015	2,200	557	3,791	507	62	2,141	1,326	12,222
May-04	613	970	2,155	545	3,713	516	62	2,082	1,369	12,025
Jun-04	595	881	2,217	540	3,745	536	62	2,117	1,505	12,198
Jul-04	587	896	2,432	592	4,108	576	70	2,299	1,657	13,217
Aug-04	624	981	2,370	577	4,003	570	69	2,267	1,610	13,071
Sep-04	597	992	2,176	530	3,676	517	63	2,102	1,433	12,086
Oct-04	660	1,124	2,273	575	3,916	533	65	2,170	1,388	12,704
Nov-04	670	1,134	2,373	600	4,089	532	66	2,259	1,418	13,141
Dec-04	677	1,217	2,544	749	4,347	542	72	2,405	1,469	14,022

Table A1 – continued

Month	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total
(GWh)										
Jan-05	732	1,277	2,681	789	4,581	565	74	2,489	1,523	14,711
Feb-05	642	1,128	2,372	698	4,053	512	67	2,251	1,356	13,079
Mar-05	679	1,188	2,476	729	4,231	551	71	2,375	1,441	13,741
Apr-05	627	1,039	2,232	565	3,847	513	63	2,156	1,346	12,388
May-05	615	995	2,193	555	3,778	522	63	2,101	1,390	12,212
Jun-05	596	906	2,248	547	3,797	541	62	2,127	1,523	12,347
Jul-05	587	919	2,452	597	4,142	580	69	2,300	1,667	13,313
Aug-05	623	998	2,410	587	4,072	576	69	2,284	1,632	13,251
Sep-05	597	1,016	2,207	537	3,728	522	63	2,114	1,448	12,232
Oct-05	661	1,140	2,296	581	3,956	537	64	2,176	1,405	12,816
Nov-05	670	1,157	2,403	608	4,140	537	67	2,269	1,435	13,286
Dec-05	680	1,242	2,574	757	4,398	547	72	2,419	1,487	14,176
Jan-06	730	1,297	2,708	797	4,627	569	74	2,495	1,537	14,834
Feb-06	642	1,149	2,399	706	4,099	517	68	2,260	1,371	13,211
Mar-06	681	1,211	2,513	740	4,294	558	72	2,394	1,462	13,925
Apr-06	626	1,057	2,243	568	3,866	513	64	2,148	1,353	12,438
May-06	616	1,017	2,232	565	3,847	529	64	2,120	1,413	12,403
Jun-06	598	928	2,275	554	3,843	546	64	2,135	1,538	12,481
Jul-06	587	943	2,483	604	4,195	586	71	2,313	1,687	13,469
Aug-06	625	1,023	2,444	595	4,128	582	68	2,297	1,652	13,414
Sep-06	599	1,043	2,233	544	3,772	526	63	2,120	1,463	12,363
Oct-06	663	1,162	2,334	591	4,022	544	65	2,195	1,429	13,005
Nov-06	670	1,179	2,435	616	4,197	542	68	2,280	1,452	13,439
Dec-06	681	1,270	2,597	764	4,437	551	72	2,421	1,499	14,292
Jan-07	730	1,318	2,748	809	4,695	576	76	2,515	1,559	15,026
Feb-07	642	1,168	2,426	714	4,146	521	68	2,270	1,386	13,341
Mar-07	681	1,236	2,537	747	4,334	561	71	2,398	1,474	14,039
Apr-07	627	1,073	2,278	576	3,926	518	66	2,164	1,374	12,602
May-07	616	1,040	2,266	573	3,904	535	66	2,132	1,432	12,564
Jun-07	598	954	2,302	560	3,889	551	64	2,142	1,554	12,614
Jul-07	589	968	2,525	615	4,265	593	69	2,332	1,710	13,666
Aug-07	628	1,051	2,480	604	4,189	589	67	2,310	1,672	13,590
Sep-07	600	1,069	2,258	550	3,814	531	64	2,124	1,478	12,488
Oct-07	666	1,187	2,376	601	4,094	552	65	2,215	1,455	13,211
Nov-07	672	1,206	2,467	624	4,251	547	68	2,291	1,470	13,596
Dec-07	681	1,297	2,630	774	4,494	556	73	2,433	1,518	14,456
Jan-08	731	1,345	2,783	819	4,755	582	74	2,527	1,579	15,195
Feb-08	667	1,236	2,548	750	4,354	545	72	2,365	1,455	13,992
Mar-08	680	1,269	2,552	751	4,361	564	70	2,391	1,482	14,120
Apr-08	624	1,119	2,334	590	4,021	531	65	2,195	1,397	12,876
May-08	617	1,068	2,291	580	3,948	539	63	2,134	1,445	12,685
Jun-08	599	975	2,330	567	3,936	555	64	2,152	1,569	12,747
Jul-08	589	990	2,571	626	4,342	600	70	2,353	1,736	13,877
Aug-08	628	1,082	2,494	607	4,213	591	69	2,304	1,679	13,667
Sep-08	601	1,088	2,302	560	3,888	538	63	2,146	1,503	12,689
Oct-08	668	1,213	2,410	610	4,153	558	66	2,229	1,474	13,381
Nov-08	673	1,232	2,482	628	4,277	549	68	2,288	1,478	13,675
Dec-08	682	1,318	2,679	788	4,577	565	73	2,458	1,545	14,685

Table A1 - continued

Month	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total
	(GWh)									
Jan-09	733	1,375	2,808	826	4,798	587	76	2,531	1,593	15,327
Feb-09	645	1,218	2,487	732	4,250	531	69	2,292	1,420	13,644
Mar-09	684	1,294	2,603	766	4,448	574	73	2,421	1,512	14,375
Apr-09	627	1,141	2,357	596	4,061	534	66	2,198	1,412	12,992
May-09	620	1,095	2,314	585	3,988	543	64	2,138	1,458	12,805
Jun-09	599	999	2,370	577	4,004	561	65	2,171	1,593	12,939
Jul-09	589	1,012	2,599	633	4,391	604	70	2,362	1,750	14,010
Aug-09	626	1,098	2,519	613	4,255	594	68	2,312	1,694	13,779
Sep-09	599	1,110	2,332	568	3,939	542	64	2,157	1,519	12,830
Oct-09	668	1,235	2,427	614	4,182	560	67	2,230	1,487	13,470
Nov-09	673	1,254	2,516	637	4,336	556	68	2,303	1,498	13,841
Dec-09	683	1,340	2,708	797	4,627	570	73	2,470	1,561	14,829
Jan-10	734	1,401	2,829	833	4,834	590	76	2,533	1,605	15,435
Feb-10	646	1,241	2,515	740	4,298	537	69	2,302	1,436	13,784
Mar-10	686	1,317	2,643	778	4,517	581	72	2,442	1,536	14,572
Apr-10	631	1,161	2,386	604	4,111	539	66	2,208	1,430	13,136
May-10	621	1,119	2,345	593	4,040	548	64	2,151	1,476	12,957
Jun-10	600	1,020	2,400	584	4,055	566	65	2,180	1,608	13,078
Jul-10	588	1,034	2,619	637	4,423	606	72	2,363	1,760	14,102
Aug-10	625	1,115	2,553	621	4,312	598	70	2,328	1,712	13,934
Sep-10	599	1,131	2,357	574	3,981	546	63	2,165	1,533	12,949
Oct-10	664	1,264	2,451	620	4,224	562	66	2,229	1,489	13,569
Nov-10	674	1,274	2,552	646	4,398	562	68	2,321	1,517	14,012
Dec-10	681	1,359	2,725	802	4,656	572	73	2,469	1,570	14,907
Jan-11	737	1,424	2,868	844	4,900	597	77	2,554	1,627	15,628
Feb-11	648	1,263	2,542	748	4,343	542	69	2,311	1,451	13,917
Mar-11	688	1,340	2,673	787	4,567	587	74	2,452	1,552	14,720
Apr-11	634	1,183	2,406	609	4,146	542	66	2,211	1,443	13,240
May-11	622	1,140	2,378	602	4,098	554	64	2,166	1,495	13,119
Jun-11	600	1,040	2,426	591	4,098	570	66	2,188	1,622	13,201
Jul-11	588	1,054	2,633	641	4,448	608	70	2,362	1,768	14,172
Aug-11	624	1,132	2,589	630	4,373	603	70	2,345	1,732	14,098
Sep-11	599	1,149	2,380	579	4,021	549	66	2,173	1,544	13,060
Oct-11	664	1,281	2,474	626	4,264	566	67	2,236	1,503	13,681
Nov-11	674	1,293	2,578	652	4,442	566	70	2,329	1,531	14,135
Dec-11	685	1,383	2,754	810	4,705	577	73	2,482	1,587	15,056

Figure A4 Annual Energy Demand – Economic Scenarios (Normal Weather)

4.0 Peak Electricity Demand

Table A2 presents the zonal peak electricity demand for each month of the forecast. This table contains the coincident peak demand. The coincident peak represents the zonal values at the time of the system peak. Table A3 presents the same information for the non-coincident peak demand. The non-coincident peak demand is the individual zonal peak demands. The sum of the non-coincident peaks always exceeds the system peak demand as the zones do not experience their individual peak demands at the same time that the system does.

Table A2 Monthly Zonal 20-Minute Coincident Peak Demand, Normal Weather

Month	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total
20-Minute Coincident Peak (MW)										
Jan-02	1,003	1,694	4,529	1,333	7,739	860	122	4,088	2,363	23,731
Feb-02	963	1,558	4,391	1,292	7,504	850	125	4,140	2,331	23,154
Mar-02	971	1,567	4,010	1,180	6,852	838	116	3,877	2,231	21,642
Apr-02	858	1,507	3,786	958	6,524	803	109	3,647	2,081	20,273
May-02	828	1,222	3,699	936	6,375	817	103	3,442	2,328	19,750
Jun-02	885	1,169	4,069	990	6,873	876	111	3,733	2,513	21,219
Jul-02	828	1,144	4,217	1,027	7,124	1,034	121	4,015	3,103	22,613
Aug-02	887	1,285	4,174	1,016	7,050	975	116	3,910	2,871	22,284
Sep-02	885	1,401	3,941	959	6,657	884	111	3,692	2,540	21,070
Oct-02	965	1,501	3,894	985	6,710	840	113	3,785	2,211	21,004
Nov-02	974	1,671	4,279	1,083	7,374	871	122	4,095	2,384	22,853
Dec-02	964	1,736	4,410	1,298	7,535	859	124	4,135	2,362	23,423
Jan-03	1,001	1,727	4,597	1,353	7,855	879	122	4,121	2,396	24,051
Feb-03	964	1,594	4,458	1,312	7,618	869	126	4,178	2,366	23,485
Mar-03	987	1,587	4,244	1,249	7,252	822	117	3,905	2,146	22,309
Apr-03	884	1,553	3,799	961	6,547	810	110	3,636	2,090	20,390
May-03	826	1,260	3,758	951	6,476	836	104	3,487	2,357	20,055
Jun-03	856	1,194	4,098	997	6,922	967	112	3,759	2,841	21,746
Jul-03	826	1,170	4,270	1,039	7,213	1,040	120	4,039	3,124	22,841
Aug-03	904	1,362	4,156	1,012	7,020	972	115	3,898	2,865	22,304
Sep-03	850	1,368	4,138	1,007	6,990	948	115	3,864	2,783	22,063
Oct-03	937	1,551	3,964	1,003	6,831	850	111	3,711	2,234	21,192
Nov-03	984	1,692	4,320	1,093	7,444	873	123	4,095	2,398	23,022
Dec-03	960	1,762	4,467	1,315	7,633	876	125	4,163	2,388	23,689
Jan-04	1,000	1,678	4,630	1,363	7,911	880	126	4,201	2,445	24,234
Feb-04	970	1,610	4,499	1,324	7,687	869	126	4,179	2,376	23,640
Mar-04	966	1,608	4,297	1,264	7,342	829	117	3,899	2,170	22,492
Apr-04	900	1,507	3,829	969	6,599	800	111	3,718	2,157	20,590
May-04	858	1,329	3,734	945	6,434	831	103	3,455	2,339	20,028
Jun-04	872	1,218	4,250	1,035	7,179	909	115	3,861	2,600	22,039
Jul-04	804	1,226	4,549	1,107	7,684	945	121	4,047	2,745	23,228
Aug-04	860	1,237	4,296	1,046	7,257	949	120	3,950	2,807	22,522
Sep-04	861	1,380	4,181	1,018	7,063	959	115	3,885	2,804	22,266
Oct-04	906	1,574	3,983	1,008	6,864	837	111	3,698	2,142	21,123
Nov-04	962	1,660	4,341	1,098	7,481	879	120	3,958	2,371	22,870
Dec-04	981	1,777	4,547	1,338	7,769	891	125	4,159	2,435	24,022

Table A2 - continued

Month	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total
20-Minute Coincident Peak (MW)										
Jan-05	1,017	1,706	4,679	1,377	7,994	887	127	4,254	2,466	24,507
Feb-05	963	1,616	4,496	1,323	7,683	876	124	4,106	2,366	23,553
Mar-05	947	1,643	4,257	1,253	7,273	862	120	4,016	2,350	22,721
Apr-05	929	1,501	3,919	992	6,754	820	112	3,764	2,245	21,036
May-05	874	1,414	3,651	924	6,291	797	101	3,445	2,262	19,759
Jun-05	861	1,242	4,309	1,049	7,278	910	114	3,850	2,633	22,246
Jul-05	800	1,259	4,592	1,118	7,757	964	122	4,097	2,773	23,482
Aug-05	900	1,397	4,340	1,056	7,330	1,007	120	4,010	2,968	23,128
Sep-05	881	1,472	4,167	1,014	7,039	961	116	3,880	2,797	22,327
Oct-05	965	1,628	3,974	1,005	6,847	868	108	3,597	2,266	21,258
Nov-05	970	1,687	4,364	1,104	7,521	890	121	4,031	2,417	23,105
Dec-05	966	1,802	4,606	1,356	7,871	892	122	4,152	2,457	24,224
Jan-06	1,018	1,732	4,734	1,393	8,090	894	128	4,278	2,494	24,761
Feb-06	991	1,729	4,496	1,323	7,683	881	124	4,152	2,405	23,784
Mar-06	945	1,669	4,310	1,269	7,365	877	120	4,046	2,377	22,978
Apr-06	911	1,524	3,975	1,005	6,849	824	113	3,768	2,264	21,233
May-06	889	1,428	3,691	934	6,361	798	103	3,447	2,281	19,932
Jun-06	856	1,275	4,364	1,062	7,371	928	116	3,894	2,659	22,525
Jul-06	815	1,273	4,638	1,129	7,834	966	122	4,102	2,795	23,674
Aug-06	883	1,425	4,406	1,072	7,442	1,011	120	4,005	2,994	23,358
Sep-06	857	1,496	4,238	1,032	7,159	933	116	3,837	2,691	22,359
Oct-06	949	1,657	4,038	1,021	6,958	870	107	3,590	2,289	21,479
Nov-06	996	1,794	4,502	1,139	7,758	904	125	4,198	2,490	23,906
Dec-06	963	1,829	4,666	1,373	7,973	909	126	4,180	2,485	24,504
Jan-07	1,022	1,846	4,816	1,417	8,229	910	127	4,220	2,499	25,086
Feb-07	981	1,695	4,673	1,375	7,985	896	129	4,305	2,468	24,507
Mar-07	950	1,685	4,353	1,281	7,438	878	120	4,048	2,388	23,141
Apr-07	911	1,548	4,034	1,020	6,951	834	112	3,796	2,291	21,497
May-07	838	1,431	3,763	952	6,485	820	102	3,425	2,272	20,088
Jun-07	871	1,290	4,410	1,073	7,449	931	115	3,898	2,682	22,719
Jul-07	835	1,303	4,496	1,094	7,595	1,084	124	4,135	3,255	23,921
Aug-07	881	1,462	4,467	1,087	7,546	1,032	121	4,052	3,025	23,673
Sep-07	869	1,477	4,325	1,053	7,306	932	114	3,806	2,690	22,572
Oct-07	956	1,640	4,092	1,035	7,051	886	111	3,700	2,314	21,785
Nov-07	980	1,824	4,568	1,156	7,872	905	126	4,192	2,514	24,137
Dec-07	982	1,888	4,694	1,382	8,021	910	129	4,267	2,497	24,770
Jan-08	1,006	1,878	4,884	1,437	8,345	912	125	4,215	2,523	25,325
Feb-08	966	1,726	4,740	1,395	8,100	898	129	4,303	2,495	24,752
Mar-08	985	1,717	4,522	1,331	7,726	859	120	4,032	2,278	23,570
Apr-08	882	1,692	4,081	1,033	7,033	847	112	3,767	2,214	21,661
May-08	831	1,420	4,034	1,021	6,952	885	107	3,606	2,496	21,352
Jun-08	863	1,354	4,378	1,066	7,395	1,016	116	3,880	2,976	23,044
Jul-08	834	1,331	4,552	1,108	7,688	1,093	124	4,159	3,281	24,170
Aug-08	914	1,550	4,440	1,081	7,500	1,021	121	4,031	3,016	23,674
Sep-08	858	1,526	4,422	1,076	7,469	998	119	3,983	2,932	23,383
Oct-08	942	1,698	4,262	1,078	7,345	894	115	3,815	2,370	22,519
Nov-08	985	1,845	4,621	1,169	7,963	917	124	4,203	2,531	24,358
Dec-08	961	1,914	4,761	1,401	8,136	919	128	4,268	2,520	25,008

Table A2 – continued

Month	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total
20-Minute Coincident Peak (MW)										
Jan-09	1,002	1,817	4,919	1,448	8,406	920	130	4,335	2,581	25,558
Feb-09	973	1,750	4,789	1,409	8,183	911	129	4,315	2,514	24,973
Mar-09	974	1,751	4,591	1,351	7,844	863	121	4,033	2,303	23,831
Apr-09	924	1,641	4,120	1,042	7,100	841	117	3,879	2,294	21,958
May-09	849	1,437	4,077	1,031	7,025	886	108	3,608	2,519	21,540
Jun-09	843	1,325	4,486	1,092	7,577	1,005	115	3,839	2,979	23,261
Jul-09	828	1,389	4,811	1,171	8,127	1,000	126	4,203	2,894	24,549
Aug-09	849	1,403	4,583	1,116	7,742	1,003	121	4,085	2,955	23,857
Sep-09	850	1,517	4,518	1,100	7,631	1,002	118	3,980	2,921	23,637
Oct-09	936	1,728	4,315	1,092	7,436	910	115	3,842	2,393	22,767
Nov-09	1,009	1,901	4,610	1,166	7,945	922	125	4,181	2,528	24,387
Dec-09	975	1,873	4,778	1,406	8,165	911	132	4,367	2,563	25,170
Jan-10	1,003	1,842	4,975	1,464	8,501	929	131	4,361	2,609	25,815
Feb-10	996	1,797	4,788	1,409	8,182	919	128	4,303	2,518	25,040
Mar-10	975	1,781	4,648	1,368	7,942	880	122	4,066	2,333	24,115
Apr-10	910	1,667	4,178	1,057	7,199	847	116	3,884	2,315	22,173
May-10	872	1,541	4,057	1,026	6,990	884	109	3,604	2,511	21,594
Jun-10	880	1,363	4,626	1,126	7,814	948	119	3,956	2,738	23,570
Jul-10	808	1,409	4,866	1,184	8,220	999	126	4,192	2,911	24,715
Aug-10	857	1,379	4,662	1,135	7,875	994	119	4,029	2,933	23,983
Sep-10	859	1,533	4,552	1,108	7,689	1,003	117	3,976	2,932	23,769
Oct-10	906	1,728	4,303	1,089	7,415	880	115	3,845	2,293	22,574
Nov-10	966	1,836	4,680	1,184	8,064	929	120	4,065	2,525	24,369
Dec-10	984	1,950	4,885	1,438	8,347	942	127	4,281	2,589	25,543
Jan-11	1,020	1,868	5,016	1,476	8,572	935	133	4,411	2,626	26,057
Feb-11	968	1,781	4,836	1,423	8,264	926	128	4,266	2,527	25,119
Mar-11	953	1,811	4,598	1,353	7,857	913	124	4,177	2,513	24,299
Apr-11	937	1,663	4,262	1,078	7,345	867	118	3,929	2,402	22,601
May-11	884	1,559	4,025	1,018	6,936	847	105	3,522	2,396	21,292
Jun-11	863	1,385	4,681	1,139	7,906	946	119	3,943	2,755	23,737
Jul-11	803	1,383	4,957	1,206	8,373	1,000	125	4,183	2,903	24,933
Aug-11	895	1,522	4,699	1,144	7,937	1,046	124	4,102	3,090	24,559
Sep-11	880	1,584	4,537	1,104	7,664	1,007	119	3,950	2,928	23,773
Oct-11	965	1,798	4,303	1,089	7,415	915	112	3,711	2,413	22,721
Nov-11	972	1,857	4,698	1,188	8,095	938	125	4,149	2,566	24,588
Dec-11	968	1,972	4,937	1,453	8,436	941	128	4,269	2,606	25,710

**Table A3 Monthly Zonal 20-Minute Non-Coincident Peak Demand,
Normal Weather**

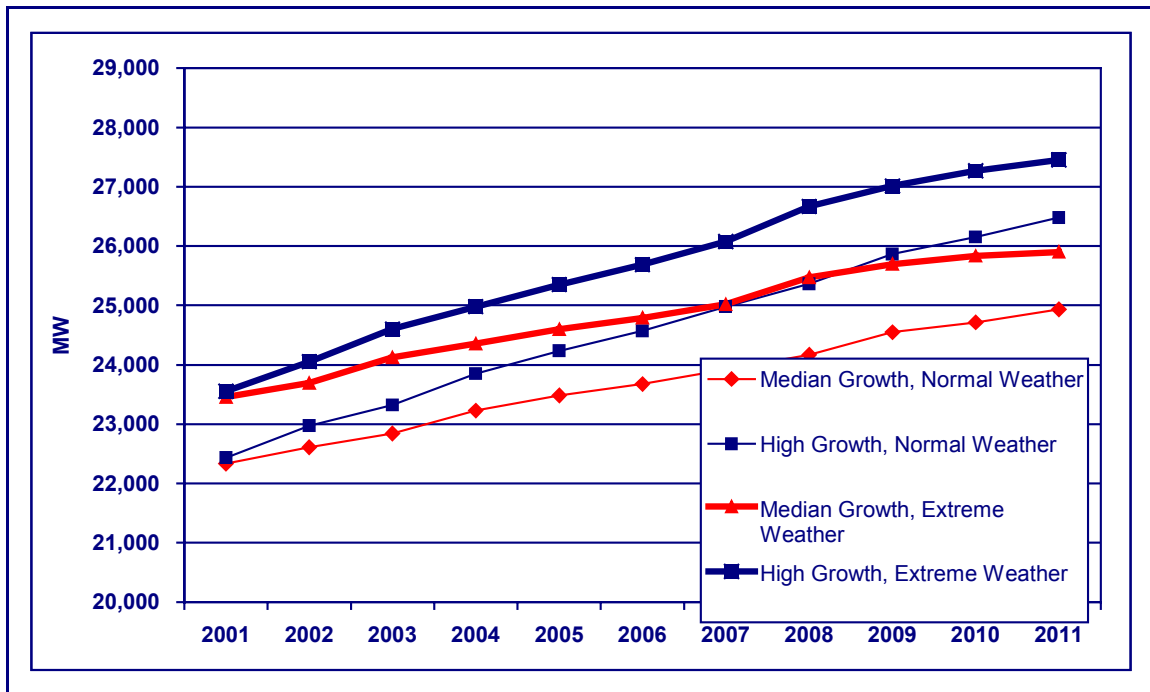
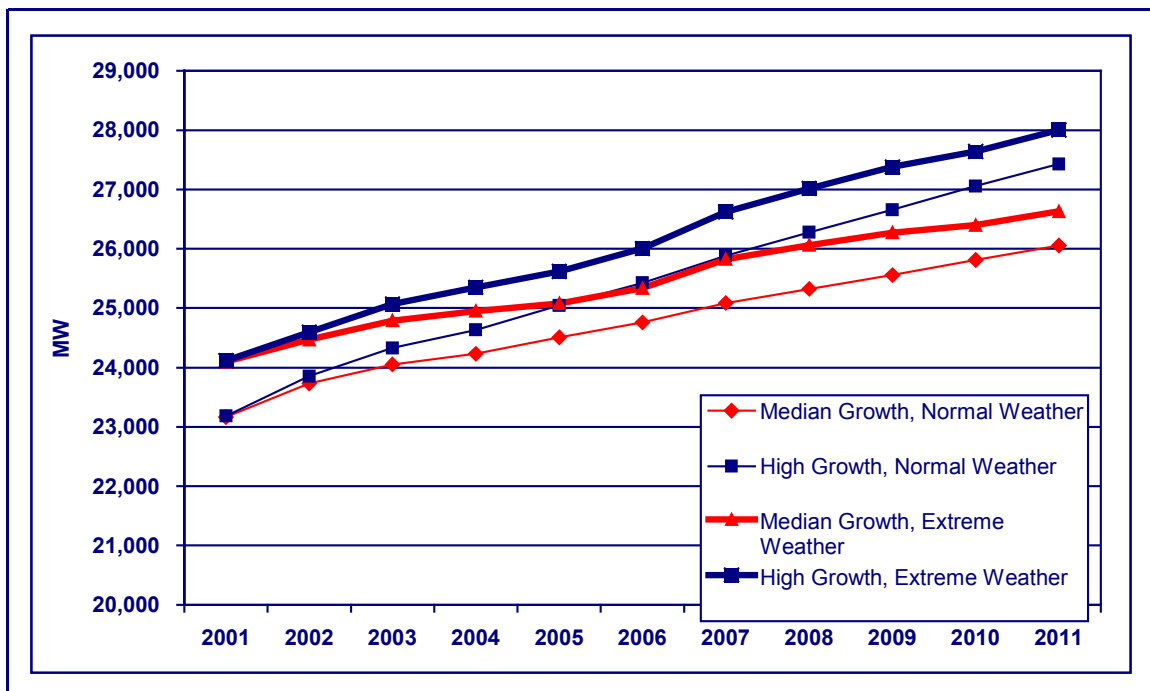
Month	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total
20-Minute Non-Coincident Peak (MW)										
Jan-02	1,044	1,855	4,529	1,333	7,739	866	125	4,172	2,396	24,059
Feb-02	1,010	1,780	4,391	1,292	7,504	858	124	4,140	2,331	23,430
Mar-02	999	1,683	4,058	1,194	6,934	838	116	3,886	2,242	21,950
Apr-02	937	1,686	3,786	958	6,524	810	109	3,647	2,119	20,576
May-02	916	1,434	3,699	936	6,375	820	103	3,455	2,328	20,066
Jun-02	889	1,365	4,069	990	6,873	942	112	3,741	2,767	21,748
Jul-02	865	1,294	4,289	1,044	7,245	1,034	120	4,026	3,103	23,020
Aug-02	914	1,510	4,203	1,023	7,099	996	117	3,915	2,977	22,754
Sep-02	921	1,495	3,941	959	6,657	899	112	3,751	2,592	21,327
Oct-02	973	1,622	3,906	988	6,730	852	113	3,785	2,233	21,202
Nov-02	999	1,750	4,279	1,083	7,374	871	123	4,129	2,400	23,008
Dec-02	997	1,862	4,410	1,298	7,535	869	125	4,196	2,386	23,678
Jan-03	1,039	1,880	4,597	1,353	7,855	879	126	4,203	2,430	24,362
Feb-03	1,020	1,834	4,458	1,312	7,618	869	125	4,178	2,366	23,780
Mar-03	1,017	1,743	4,244	1,249	7,252	833	117	3,905	2,233	22,593
Apr-03	936	1,741	3,799	961	6,547	822	109	3,636	2,139	20,690
May-03	924	1,475	3,758	951	6,476	836	104	3,487	2,357	20,368
Jun-03	898	1,388	4,098	997	6,922	967	112	3,764	2,841	21,987
Jul-03	856	1,338	4,275	1,041	7,222	1,042	121	4,049	3,124	23,068
Aug-03	916	1,520	4,250	1,034	7,178	995	118	3,937	2,994	22,942
Sep-03	922	1,539	4,138	1,007	6,990	948	116	3,876	2,783	22,319
Oct-03	987	1,661	3,964	1,003	6,831	850	113	3,775	2,248	21,432
Nov-03	1,013	1,768	4,320	1,093	7,444	873	124	4,141	2,416	23,192
Dec-03	1,011	1,937	4,469	1,315	7,636	876	126	4,227	2,414	24,011
Jan-04	1,052	1,929	4,630	1,363	7,911	890	125	4,201	2,484	24,585
Feb-04	1,016	1,838	4,499	1,324	7,687	877	125	4,179	2,380	23,925
Mar-04	1,001	1,712	4,297	1,264	7,342	859	120	4,032	2,337	22,964
Apr-04	943	1,700	3,829	969	6,599	815	111	3,718	2,157	20,841
May-04	911	1,479	3,734	945	6,434	850	103	3,459	2,427	20,342
Jun-04	896	1,437	4,250	1,035	7,179	977	115	3,863	2,872	22,624
Jul-04	861	1,367	4,549	1,107	7,684	1,053	122	4,075	3,154	23,972
Aug-04	912	1,532	4,296	1,046	7,257	952	118	3,954	2,807	22,874
Sep-04	912	1,551	4,183	1,018	7,066	959	116	3,887	2,804	22,496
Oct-04	945	1,742	3,983	1,008	6,864	846	110	3,698	2,368	21,564
Nov-04	1,009	1,922	4,341	1,098	7,481	879	120	4,016	2,383	23,249
Dec-04	999	1,965	4,547	1,338	7,769	891	126	4,222	2,464	24,321

Table A3 – continued

Month	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total
20-Minute Non-Coincident Peak (MW)										
Jan-05	1,040	1,982	4,679	1,377	7,994	900	127	4,254	2,510	24,863
Feb-05	1,016	1,888	4,496	1,323	7,683	879	123	4,106	2,372	23,886
Mar-05	1,011	1,763	4,347	1,279	7,428	862	121	4,035	2,357	23,203
Apr-05	954	1,668	3,919	992	6,754	832	112	3,764	2,245	21,240
May-05	917	1,551	3,699	936	6,374	852	104	3,479	2,442	20,354
Jun-05	900	1,457	4,312	1,050	7,284	980	115	3,852	2,890	22,840
Jul-05	872	1,390	4,592	1,118	7,757	1,062	122	4,097	3,173	24,183
Aug-05	923	1,558	4,369	1,063	7,380	1,007	120	4,022	2,968	23,410
Sep-05	924	1,583	4,200	1,022	7,095	967	116	3,880	2,797	22,584
Oct-05	979	1,722	3,974	1,005	6,847	868	110	3,697	2,389	21,591
Nov-05	1,009	1,933	4,379	1,108	7,546	890	122	4,085	2,432	23,504
Dec-05	1,001	2,033	4,606	1,356	7,871	899	126	4,226	2,486	24,604
Jan-06	1,045	1,988	4,737	1,394	8,095	906	128	4,278	2,523	25,094
Feb-06	1,028	1,927	4,496	1,323	7,683	882	124	4,152	2,405	24,020
Mar-06	1,022	1,807	4,344	1,278	7,422	877	121	4,063	2,383	23,317
Apr-06	950	1,717	3,975	1,005	6,849	840	113	3,768	2,264	21,481
May-06	921	1,555	3,745	948	6,454	870	103	3,463	2,467	20,526
Jun-06	914	1,516	4,380	1,066	7,399	993	116	3,894	2,917	23,195
Jul-06	873	1,421	4,644	1,130	7,845	1,074	123	4,103	3,199	24,412
Aug-06	922	1,579	4,439	1,081	7,499	1,011	120	4,018	2,994	23,663
Sep-06	934	1,616	4,263	1,038	7,200	937	115	3,838	2,708	22,649
Oct-06	973	1,785	4,038	1,021	6,958	874	111	3,720	2,401	21,881
Nov-06	1,007	1,866	4,502	1,139	7,758	904	127	4,261	2,506	24,070
Dec-06	993	2,040	4,666	1,373	7,973	909	127	4,246	2,515	24,842
Jan-07	1,046	2,020	4,816	1,417	8,229	910	129	4,304	2,534	25,405
Feb-07	1,023	1,933	4,673	1,375	7,985	896	129	4,305	2,468	24,787
Mar-07	1,009	1,839	4,355	1,282	7,442	878	121	4,067	2,393	23,386
Apr-07	938	1,718	4,034	1,020	6,951	842	113	3,796	2,291	21,703
May-07	916	1,566	3,806	963	6,559	872	104	3,486	2,489	20,761
Jun-07	908	1,538	4,439	1,080	7,498	996	116	3,898	2,942	23,415
Jul-07	873	1,462	4,638	1,129	7,835	1,084	124	4,143	3,255	24,543
Aug-07	932	1,633	4,516	1,099	7,627	1,038	121	4,052	3,128	24,146
Sep-07	918	1,639	4,325	1,053	7,306	947	116	3,900	2,742	22,946
Oct-07	974	1,849	4,103	1,038	7,071	888	113	3,781	2,412	22,229
Nov-07	1,003	1,921	4,568	1,156	7,872	909	127	4,255	2,531	24,342
Dec-07	999	2,032	4,713	1,387	8,053	917	130	4,360	2,535	25,126
Jan-08	1,047	2,045	4,884	1,437	8,345	918	129	4,334	2,559	25,698
Feb-08	1,014	1,985	4,740	1,395	8,100	907	129	4,303	2,495	25,068
Mar-08	1,016	1,885	4,522	1,331	7,726	870	120	4,032	2,363	23,865
Apr-08	936	1,914	4,081	1,033	7,033	856	113	3,767	2,268	22,001
May-08	920	1,645	4,057	1,026	6,992	885	108	3,606	2,496	21,735
Jun-08	908	1,549	4,415	1,075	7,458	1,016	116	3,885	2,976	23,398
Jul-08	865	1,501	4,584	1,116	7,743	1,093	124	4,168	3,281	24,475
Aug-08	929	1,695	4,571	1,113	7,721	1,048	121	4,061	3,148	24,407
Sep-08	927	1,701	4,459	1,085	7,532	998	119	3,993	2,932	23,746
Oct-08	993	1,895	4,262	1,078	7,345	894	117	3,906	2,386	22,876
Nov-08	1,013	1,942	4,621	1,169	7,963	917	128	4,275	2,552	24,580
Dec-08	1,011	2,094	4,761	1,401	8,136	919	130	4,359	2,548	25,359

Table A3 – continued

Month	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total
20-Minute Non-Coincident Peak (MW)										
Jan-09	1,053	2,087	4,926	1,450	8,418	934	129	4,335	2,620	25,952
Feb-09	1,018	2,042	4,789	1,409	8,183	918	129	4,315	2,518	25,321
Mar-09	1,015	1,916	4,591	1,351	7,844	889	121	4,064	2,395	24,186
Apr-09	944	1,894	4,120	1,042	7,100	872	116	3,879	2,294	22,261
May-09	917	1,652	4,112	1,040	7,086	886	108	3,610	2,519	21,930
Jun-09	907	1,585	4,486	1,092	7,577	1,018	117	3,927	3,011	23,720
Jul-09	864	1,532	4,843	1,179	8,181	1,101	126	4,211	3,300	25,337
Aug-09	927	1,702	4,629	1,127	7,819	1,055	122	4,085	3,141	24,607
Sep-09	914	1,715	4,518	1,100	7,631	1,014	120	4,022	2,950	23,984
Oct-09	983	1,912	4,315	1,092	7,436	910	118	3,936	2,402	23,104
Nov-09	1,014	1,989	4,626	1,170	7,972	922	127	4,256	2,552	24,628
Dec-09	1,011	2,099	4,818	1,418	8,233	926	130	4,367	2,563	25,565
Jan-10	1,055	2,098	4,983	1,467	8,515	943	130	4,361	2,642	26,194
Feb-10	1,026	2,091	4,796	1,411	8,195	927	129	4,303	2,531	25,409
Mar-10	1,009	1,973	4,648	1,368	7,942	911	125	4,187	2,491	24,654
Apr-10	949	1,900	4,191	1,060	7,223	861	116	3,884	2,315	22,499
May-10	918	1,720	4,097	1,036	7,060	906	108	3,608	2,585	22,038
Jun-10	908	1,638	4,626	1,126	7,814	1,033	119	3,992	3,038	24,294
Jul-10	864	1,562	4,905	1,194	8,285	1,108	126	4,211	3,319	25,574
Aug-10	917	1,717	4,662	1,135	7,875	999	122	4,076	2,963	24,466
Sep-10	907	1,748	4,552	1,108	7,689	1,010	120	4,016	2,959	24,109
Oct-10	946	1,937	4,303	1,089	7,415	893	115	3,845	2,516	23,059
Nov-10	1,012	2,099	4,680	1,184	8,064	929	124	4,168	2,538	24,798
Dec-10	1,000	2,143	4,885	1,438	8,347	942	131	4,375	2,620	25,881
Jan-11	1,044	2,166	5,016	1,476	8,572	952	132	4,411	2,669	26,438
Feb-11	1,021	2,133	4,836	1,423	8,264	929	127	4,266	2,533	25,532
Mar-11	1,018	2,032	4,689	1,380	8,012	913	125	4,185	2,513	24,867
Apr-11	961	1,893	4,267	1,079	7,353	881	117	3,929	2,402	22,882
May-11	917	1,747	4,043	1,023	6,967	906	108	3,617	2,601	21,929
Jun-11	911	1,651	4,681	1,139	7,906	1,031	119	3,977	3,056	24,471
Jul-11	875	1,580	4,957	1,206	8,373	1,114	126	4,227	3,335	25,793
Aug-11	930	1,741	4,729	1,151	7,988	1,056	124	4,146	3,124	24,989
Sep-11	920	1,767	4,546	1,107	7,679	1,020	120	4,012	2,955	24,126
Oct-11	979	1,974	4,303	1,089	7,415	915	115	3,842	2,539	23,171
Nov-11	1,009	2,107	4,713	1,192	8,121	938	126	4,234	2,583	25,023
Dec-11	1,003	2,207	4,937	1,453	8,436	948	131	4,374	2,637	26,126

Figure A5 Summer Peaks, Various Scenarios**Figure A6 Winter Peaks, Various Scenarios**

Appendix B – Ontario Electricity System – Maps

List of Figures

Figure B1 Ontario Electricity System 69

Figure B2 Northern Ontario Electricity System 70

Figure B3 Southern and Eastern Ontario Electricity System 71

Figure B1 Ontario Electricity System

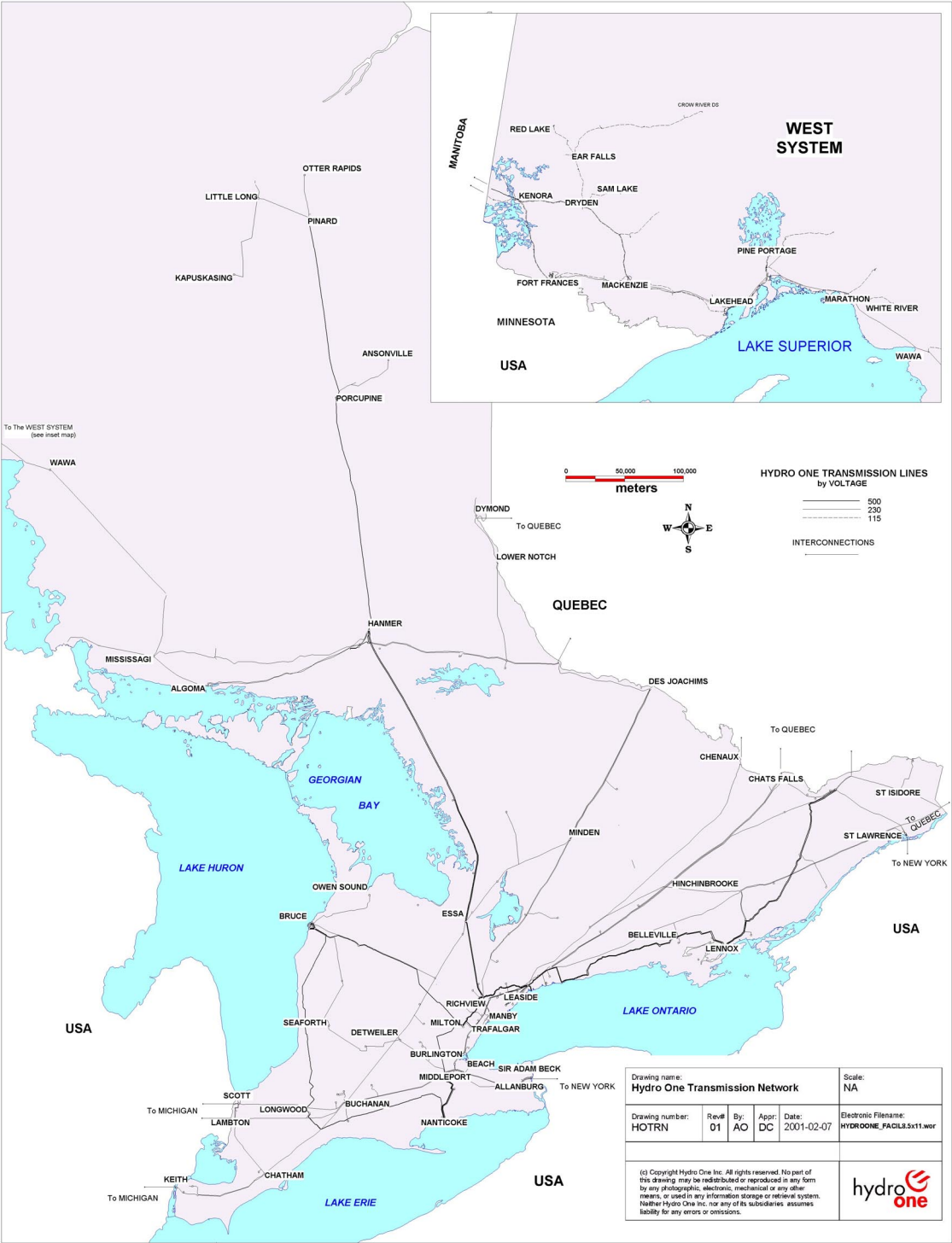


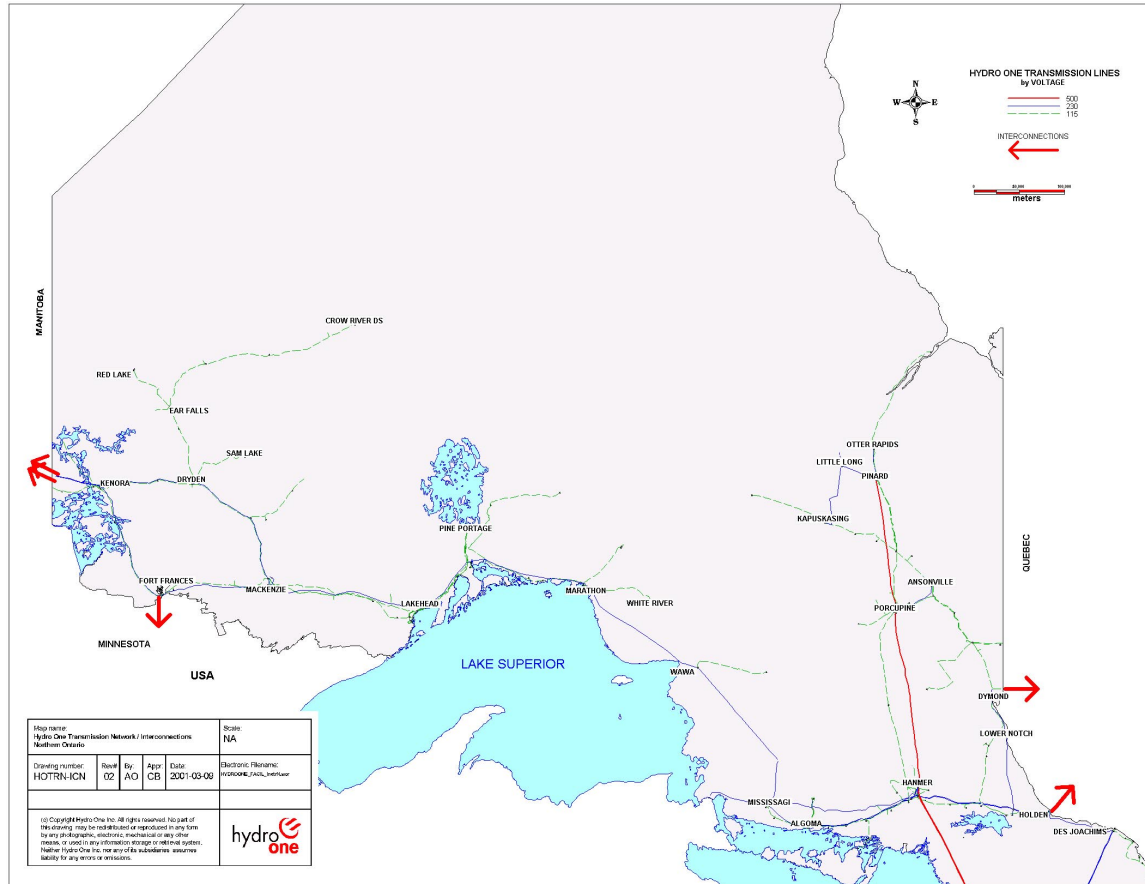
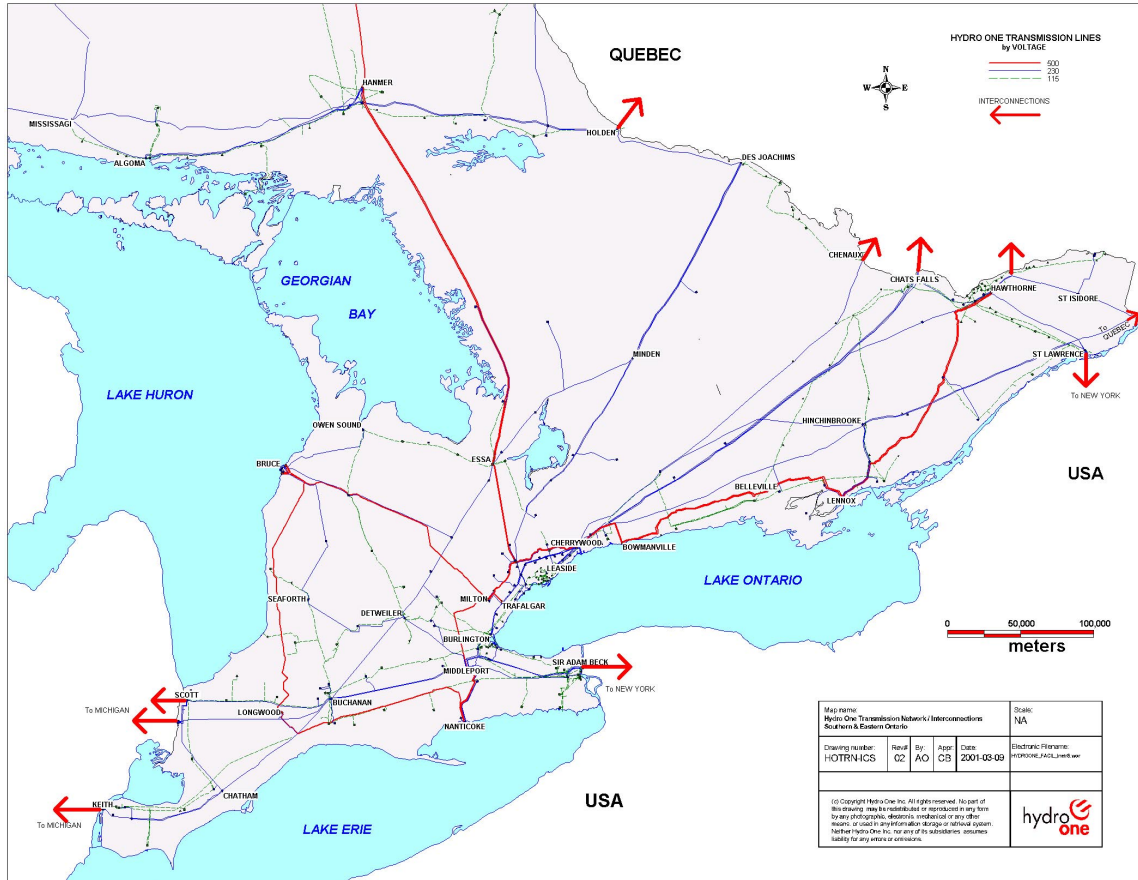
Figure B2 Northern Ontario Electricity System

Figure B3 Southern and Eastern Ontario Electricity System

Appendix C – System Resource Details

Table of Contents

1.0	Generation Reserve Requirement.....	75
1.1	Method	75
1.2	Demand Forecast Uncertainty Due to Weather	76
1.3	Resource Representation	76
1.4	Representation of Interconnected Systems	77
1.5	Transmission System.....	77
2.0	Resources Adequacy Assessment Tables.....	78

List of Tables

Table C2.1	Reserve Margins Under Low Demand Growth, Summer Peak, Resource Scenario #1	78
Table C2.2	Reserve Margins Under Low Demand Growth, Winter Peak, Resource Scenario #1	78
Table C2.3	Reserve Margins Under Median Demand Growth, Summer Peak, Resource Scenario #1.....	79
Table C2.4	Reserve Margins Under Median Demand Growth, Winter Peak, Resource Scenario #1.....	79
Table C2.5	Reserve Margins Under High Demand Growth, Summer Peak, Resource Scenario #1.....	80
Table C2.6	Reserve Margins Under High Demand Growth, Winter Peak, Resource Scenario #1	80
Table C2.7	Change in Reserve Margins from Resource Scenario #1, Low Demand Growth, Summer Peak.....	81
Table C2.8	Change in Reserve Margins from Resource Scenario #1, Low Demand Growth, Winter Peak	81
Table C2.9	Change in Reserve Margins from Resource Scenario #1, Median Demand Growth, Summer Peak.....	82
Table C2.10	Change in Reserve Margins from Resource Scenario #1, Median Demand Growth, Winter Peak	82
Table C2.11	Change in Reserve Margins from Resource Scenario #1, High Demand Growth, Summer Peak	83
Table C2.12	Change in Reserve Margins from Resource Scenario #1, High Demand Growth, Winter Peak	83

List of Figures

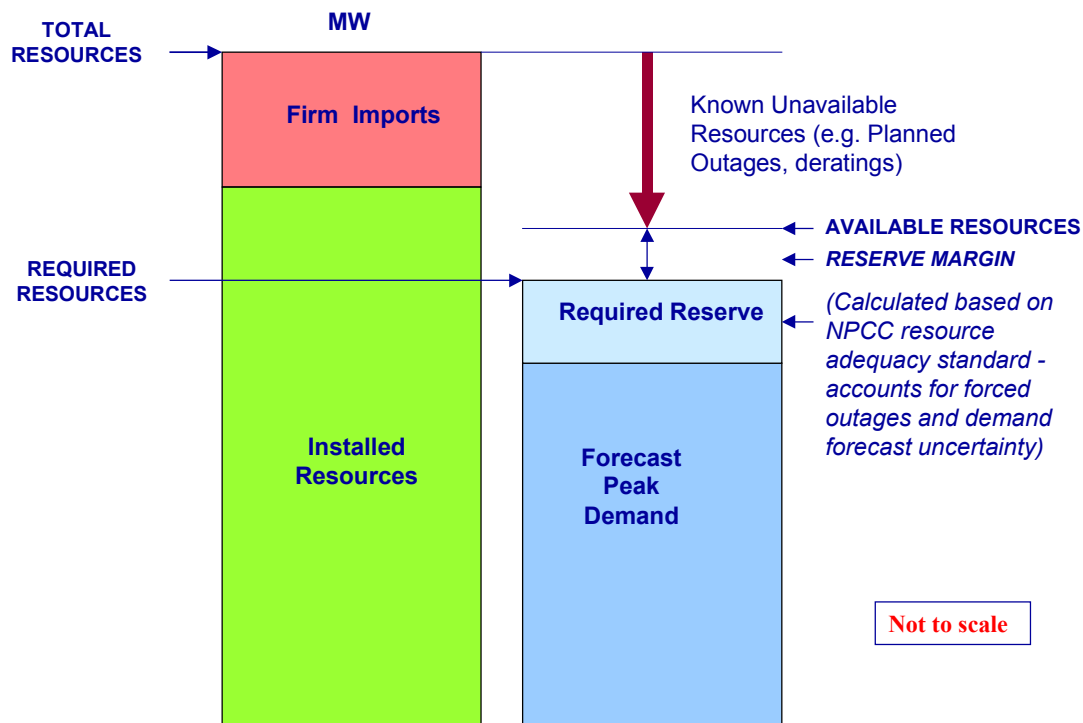
Figure C1	Reserve Margin.....	75
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1.0 Generation Reserve Requirement

1.1 Method

The IMO uses a Load and Capacity (L&C) model to determine the Required Reserves from week to week. The mix of generating plant, generating unit forced outage rates, the demand forecast and its uncertainty are inputs to the model. A resource adequacy standard equivalent to an annual loss of load probability (LOLP) of 0.1 is used to determine the Reserve Requirement for each week of the planning year.

Figure C1 Reserve Margin



The probabilistic calculation of the Required Reserve for each planning week is calculated as follows:

Based on the generating units' Maximum Continuous Ratings and Forced Outage Rates, a Capacity on Outage Probability Table is built, in which the probabilities of having various amounts of capacity on forced outage are determined and stored.

The Required Reserve calculation is then executed in an iterative manner. In each iteration an amount of Generation Reserve is assumed and an associated $LOLP_{CALC}$ is derived, convolving the Demand Forecast Uncertainty (DFU) corresponding to the Demand value (which assumes normal distribution) with the Capacity on Outage Probability Table. The iterative process is repeated with small changes to the assumed Generation Reserve until the $LOLP_{CALC}$ becomes equal or less than the target of 0.. When this condition becomes true, the assumed level of Generation Reserve equals the Required Reserve necessary to meet the reliability target.

The adequacy of the available resources to meet the demand over the study period can then be assessed, in a deterministic calculation, as shown in Figure C1. For each planning week, the minimum level of Available Resources is determined, starting with the total resources then subtracting generator deratings, planned and long term unplanned generator outages, generation constrained off due to transmission interface limitations and allowances for non-utility and hydroelectric generation production below rated capacity. The Reserve Margin is then obtained by subtraction of the Required Resources (equal to Demand plus the Required Reserve) from the minimum Available Resources. Whenever the Reserve Margin is positive the reliability criterion is met or exceeded (i.e. the LOLP is less than or equal to 0.1).

The actual LOLP for each planning week can then be calculated in a similar way as described above. This time the Available Generation Reserve is known, so the LOLP can be derived in one iteration, by convolving the DFU corresponding to the Demand value (normal distribution assumed) with the Capacity on Outage Probability Table.

Finally the annual LOLE can be derived using the individual LOLPs from each of the component planning weeks.

1.2 Demand Forecast Uncertainty Due to Weather

The total energy demand is split into weather and non-weather components. A normal distribution of weather swings, in any week, is provided by input of the associated standard deviation. This data is obtained from 30-year weather statistics and is updated annually. The standard deviation of weather-related demand (Demand Forecast Uncertainty or DFU) varies between about 2% and 7% through the year. The peak demand probability distribution in any week is available to the L&C program.

The total demand value includes loads that can be dispatched off or otherwise interrupted in the case of a shortfall in reserves. For modeling purposes, the dispatchable demand is assumed to be supplied therefore it is included in the demand forecast when the Required Reserve is probabilistically calculated. At the deterministic assessment stage, dispatchable demands and interruptible loads are deducted from the Ontario demand. The IMO uses a value of 300 MW based on current anticipated levels.

1.3 Resource Representation

1.3.1 Unit Ratings

Thermal generating units are assumed to be capable of operating at a level equal to their normal Maximum Continuous Rating (MCR) or as otherwise identified to the IMO. Hydroelectric station peak outputs are based on one hour sustainable capability determined from about 30 years of record; these values are provided by the generation plant owners. The peak and energy output of all combustion turbines varies considerably with changes in ambient air temperature and, hence, both summer and winter values are included.

1.3.2 Forced Outage Rates of Generating Units

Derating-Adjusted Forced outage rates that are used for each unit reflect both forced outages and periods of derated output. The values are provided by the generation plant owners, based on past

experience modified to reflect forecast improvements from maintenance activities or declines due to age or need for repair.

1.4 Representation of Interconnected Systems

There are five interconnected systems that could provide additional resources to supply Ontario namely Manitoba, Quebec, Minnesota, Michigan and New York. For this study, outside generation resources that would bid into Ontario Market as a result of increasing market prices are not included in the calculation of the Reserve Margin. Their availability, however, is taken into account in the assessments, whenever negative margins are indicated.

1.5 Transmission System

The Ontario IMO-controlled grid consists of a robust southern grid and a sparse northern grid. The southern grid has few binding limits and these have been accounted for in this study. The northwestern part of the northern grid has limitations, which potentially constrain-off generation capacity. Some 25 Hz generation in Niagara zone is constrained off by frequency changer capability. Also, under the generation addition scenarios presented as Resource Scenarios #2 and #3, the relatively large generation capacity additions in the West zone of the system at times would cause some West zone generation to be constrained off because of the NBLIP transmission interface limitation. The amount of constrained-off generation varies at the time of seasonal peaks between 0 and about 2,100 MW, depending on the demand level and the amount of total generating capacity in the West zone. Constrained-off generation is subtracted from the Available Resources when calculating the Reserve Margins.

2.0 Resources Adequacy Assessment Tables

The following tables provide the numeric results of the resource adequacy assessment. They support Figure 4.2 in Section 4.2 and the statements made in Section 4.2.1 to 4.2.4.

Table C2.1 Reserve Margins Under Low Demand Growth, Summer Peak, Resource Scenario #1

Year	Summer Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW	Peak LOLP
2002	22,383	21-Jul-02	25,089	3,006	3,381	13.4	15.1	-375	0.13
2003	22,379	20-Jul-03	27,108	5,029	3,319	22.5	14.8	1,710	0.01
2004	22,668	11-Jul-04	27,630	5,262	3,416	23.2	15.1	1,846	0.01
2005	22,866	10-Jul-05	27,679	5,113	3,524	22.4	15.4	1,589	0.01
2006	23,001	09-Jul-06	27,690	4,989	3,441	21.7	15.0	1,548	0.01
2007	23,188	22-Jul-07	27,616	4,727	3,077	20.4	13.3	1,650	0.01
2008	23,378	20-Jul-08	27,610	4,533	3,236	19.4	13.8	1,297	0.02
2009	23,700	12-Jul-09	27,636	4,236	3,338	17.9	14.1	898	0.03
2010	23,814	11-Jul-10	27,669	4,155	3,453	17.4	14.5	702	0.05
2011	23,981	10-Jul-11	27,635	3,953	3,547	16.5	14.8	406	0.07

Table C2.2 Reserve Margins Under Low Demand Growth, Winter Peak, Resource Scenario #1

Year	Winter Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW	Peak LOLP
2002	23,670	13-Jan-02	26,540	3,171	3,406	13.4	14.4	-235	0.12
2003	23,665	12-Jan-03	27,106	3,742	2,954	15.8	12.5	788	0.03
2004	23,695	18-Jan-04	28,178	4,784	2,814	20.2	11.9	1,970	0.01
2005	23,913	23-Jan-05	28,197	4,584	3,108	19.2	13.0	1,476	0.01
2006	24,111	22-Jan-06	28,185	4,374	3,136	18.1	13.0	1,238	0.02
2007	24,378	14-Jan-07	28,139	4,061	2,858	16.7	11.7	1,203	0.01
2008	24,556	13-Jan-08	28,119	3,864	2,948	15.7	12.0	916	0.02
2009	24,730	18-Jan-09	28,157	3,728	2,958	15.1	12.0	770	0.03
2010	24,933	17-Jan-10	28,155	3,523	2,936	14.1	11.8	587	0.04
2011	25,124	23-Jan-11	28,170	3,346	3,306	13.3	13.2	40	0.09

Table C2.3 Reserve Margins Under Median Demand Growth, Summer Peak, Resource Scenario #1

Year	Summer Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW	Peak LOLP
2002	22,611	21-Jul-02	25,104	2,793	3,421	12.4	15.1	-628	0.16
2003	22,841	20-Jul-03	27,144	4,603	3,300	20.2	14.4	1,303	0.02
2004	23,228	11-Jul-04	27,675	4,747	3,396	20.4	14.6	1,351	0.02
2005	23,482	10-Jul-05	27,727	4,545	3,497	19.4	14.9	1,048	0.03
2006	23,674	09-Jul-06	27,742	4,368	3,428	18.5	14.5	940	0.04
2007	23,921	22-Jul-07	27,671	4,050	3,085	16.9	12.9	965	0.03
2008	24,170	20-Jul-08	27,670	3,800	3,301	15.7	13.7	499	0.05
2009	24,549	12-Jul-09	27,699	3,450	3,445	14.1	14.0	5	0.10
2010	24,715	11-Jul-10	27,735	3,320	3,586	13.4	14.5	-266	0.13
2011	24,933	10-Jul-11	27,705	3,072	3,719	12.3	14.9	-647	0.17

Table C2.4 Reserve Margins Under Median Demand Growth, Winter Peak, Resource Scenario #1

Year	Winter Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW	Peak LOLP
2002	23,731	13-Jan-02	26,544	3,113	3,417	13.1	14.4	-304	0.12
2003	24,051	12-Jan-03	27,137	3,386	3,034	14.1	12.6	352	0.05
2004	24,232	18-Jan-04	28,200	4,268	2,830	17.6	11.7	1,438	0.01
2005	24,507	23-Jan-05	28,205	3,998	3,144	16.3	12.8	854	0.03
2006	24,761	22-Jan-06	28,196	3,735	3,215	15.1	13.0	520	0.05
2007	25,086	14-Jan-07	28,149	3,363	3,014	13.4	12.0	349	0.05
2008	25,325	13-Jan-08	28,149	3,124	3,117	12.3	12.3	7	0.10
2009	25,558	18-Jan-09	28,196	2,938	3,136	11.5	12.3	-198	0.11
2010	25,815	17-Jan-10	28,196	2,681	3,134	10.4	12.1	-453	0.14
2011	26,057	23-Jan-11	28,196	2,439	3,483	9.4	13.4	-1,044	0.24

Table C2.5 Reserve Margins Under High Demand Growth, Summer Peak, Resource Scenario #1

Year	Summer Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW	Peak LOLP
2002	22,970	21-Jul-02	25,113	2,442	3,509	10.6	15.3	-1067	0.23
2003	23,320	20-Jul-03	27,153	4,132	3,332	17.7	14.3	800	0.04
2004	23,850	11-Jul-04	27,685	4,135	3,435	17.3	14.4	700	0.05
2005	24,234	10-Jul-05	27,737	3,803	3,589	15.7	14.8	214	0.08
2006	24,572	09-Jul-06	27,754	3,482	3,597	14.2	14.6	-115	0.11
2007	24,979	22-Jul-07	27,679	3,000	3,331	12.0	13.3	-331	0.12
2008	25,365	20-Jul-08	27,677	2,612	3,571	10.3	14.1	-959	0.22
2009	25,868	12-Jul-09	27,705	2,137	3,734	8.3	14.4	-1597	0.34
2010	26,152	11-Jul-10	27,741	1,889	3,902	7.2	14.9	-2013	0.40
2011	26,480	10-Jul-11	27,711	1,530	4,059	5.8	15.3	-2529	0.50

Table C2.6 Reserve Margins Under High Demand Growth, Winter Peak, Resource Scenario #1

Year	Winter Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW	Peak LOLP
2002	23,855	13-Jan-02	26,541	2,986	3,451	12.5	14.5	-465	0.11
2003	24,329	12-Jan-03	27,135	3,106	3,100	12.8	12.7	6	0.10
2004	24,633	18-Jan-04	28,200	3,867	2,912	15.7	11.8	955	0.02
2005	25,046	23-Jan-05	28,205	3,459	3,276	13.8	13.1	183	0.07
2006	25,429	22-Jan-06	28,196	3,067	3,391	12.1	13.3	-324	0.12
2007	25,887	14-Jan-07	28,149	2,562	3,199	9.9	12.4	-637	0.17
2008	26,279	13-Jan-08	28,149	2,170	3,337	8.3	12.7	-1,167	0.27
2009	26,661	18-Jan-09	28,196	1,835	3,382	6.9	12.7	-1,547	0.38
2010	27,058	17-Jan-10	28,196	1,438	3,414	5.3	12.6	-1,976	0.52
2011	27,430	23-Jan-11	28,196	1,066	3,799	3.9	13.8	-2,733	0.64

**Table C2.7 Change in Reserve Margins from Resource Scenario #1,
Low Demand Growth, Summer Peak**

Year	Reserve Margin, MW				
	Resource Scenario #1 -2000 MW	Resource Scenario #1 -1000 MW	Resource Scenario #1	Resource Scenario #2	Resource Scenario #3
2002	-2,375	-1,375	-375	130	218
2003	-290	710	1,710	4,264	5,302
2004	-154	846	1,846	5,515	5,811
2005	-411	589	1,589	5,279	5,575
2006	-452	548	1,548	5,253	5,549
2007	-350	650	1,650	5,498	6,098
2008	-703	297	1,297	5,145	5,763
2009	-1,102	-102	898	4,679	4,975
2010	-1,298	-298	702	4,494	4,790
2011	-1,594	-594	406	4,211	4,507

**Table C2.8 Change in Reserve Margins from Resource Scenario #1,
Low Demand Growth, Winter Peak**

Year	Reserve Margin, MW				
	Resource Scenario #1 -2000 MW	Resource Scenario #1 -1000 MW	Resource Scenario #1	Resource Scenario #2	Resource Scenario #3
2002	-2,235	-1,235	-235	-16	72
2003	-1,212	-212	788	1,832	1,920
2004	-30	970	1,970	4,579	4,875
2005	-524	476	1,476	4,863	5,159
2006	-762	238	1,238	4,646	4,942
2007	-797	203	1,203	4,612	4,908
2008	-1,084	-84	916	4,341	4,637
2009	-1,230	-230	770	4,242	4,538
2010	-1,413	-413	587	4,080	4,376
2011	-1,960	-960	40	3,543	3,839

**Table C2.9 Change in Reserve Margins from Resource Scenario #1,
Median Demand Growth, Summer Peak**

Year	Reserve Margin, MW				
	Resource Scenario #1 -2000 MW	Resource Scenario #1 -1000 MW	Resource Scenario #1	Resource Scenario #2	Resource Scenario #3
2002	-2,628	-1,628	-628	-123	-35
2003	-697	303	1,303	3,857	4,959
2004	-649	351	1,351	5,094	5,390
2005	-952	48	1,048	4,820	5,116
2006	-1,060	-60	940	4,734	5,030
2007	-1,035	-35	965	4,813	5,515
2008	-1,501	-501	499	4,347	5,075
2009	-1,995	-995	5	3,853	4,194
2010	-2,266	-1,266	-266	3,582	3,940
2011	-2,647	-1,647	-647	3,201	3,551

**Table C2.10 Change in Reserve Margins from Resource Scenario #1,
Median Demand Growth, Winter Peak**

Year	Reserve Margin, MW				
	Resource Scenario #1 -2000 MW	Resource Scenario #1 -1000 MW	Resource Scenario #1	Resource Scenario #2	Resource Scenario #3
2002	-2,304	-1,304	-304	-85	3
2003	-1,648	-648	352	1,396	1,484
2004	-562	438	1,438	4,118	4,414
2005	-1,146	-146	854	4,319	4,615
2006	-1,480	-480	520	4,013	4,309
2007	-1,651	-651	349	3,847	4,143
2008	-1,993	-993	7	3,529	3,825
2009	-2,198	-1,198	-198	3,382	3,678
2010	-2,453	-1,453	-453	3,155	3,451
2011	-3,044	-2,044	-1,044	2,581	2,877

**Table C2.11 Change in Reserve Margins from Resource Scenario #1,
High Demand Growth, Summer Peak**

Year	Reserve Margin, MW				
	Resource Scenario #1 -2000 MW	Resource Scenario #1 -1000 MW	Resource Scenario #1	Resource Scenario #2	Resource Scenario #3
2002	-3,067	-2,067	-1,067	-562	-474
2003	-1,200	-200	800	3,354	4,515
2004	-1,300	-300	700	4,515	4,811
2005	-1,786	-786	214	4,062	4,369
2006	-2,115	-1,115	-115	3,733	4,078
2007	-2,331	-1,331	-331	3,517	4,310
2008	-2,959	-1,959	-959	2,889	3,721
2009	-3,597	-2,597	-1,597	2,251	2,707
2010	-4,013	-3,013	-2,013	1,835	2,321
2011	-4,529	-3,529	-2,529	1,319	1,839

**Table C2.12 Change in Reserve Margins from Resource Scenario #1,
High Demand Growth, Winter Peak**

Year	Reserve Margin, MW				
	Resource Scenario #1 -2000 MW	Resource Scenario #1 -1000 MW	Resource Scenario #1	Resource Scenario #2	Resource Scenario #3
2002	-2,465	-1,465	-465	-246	-158
2003	-1,994	-994	6	1,050	1,138
2004	-1,045	-45	955	3,679	3,975
2005	-1,817	-817	183	3,706	4,002
2006	-2,324	-1,324	-324	3,242	3,538
2007	-2,637	-1,637	-637	2,944	3,240
2008	-3,167	-2,167	-1,167	2,455	2,751
2009	-3,547	-2,547	-1,547	2,154	2,450
2010	-3,976	-2,976	-1,976	1,769	2,065
2011	-4,733	-3,733	-2,733	1,043	1,339

Appendix D – Transmission System Details

Table of Contents

1.0	Transmission System Description.....	87
1.1	Transmission System Interfaces.....	87
1.2	Interface Characteristics	88
1.3	Transmission System Zones.....	92
1.4	Transmission System Interconnection Capabilities and External Markets	93
2.0	Definitions and Limits of Ontario's Interfaces	97
2.1	Definitions of Ontario's Interfaces	97
2.2	Limits of Ontario's Interfaces	99
3.0	Definitions and Limits of Ontario's Interconnections	100
3.1	Definitions of Ontario's Interconnections	100
3.2	Flow Limits of Ontario's Interconnections	102

List of Tables

Table D2.1	Ontario's Interface Base Limits	99
Table D3.1	Ontario's Interconnection Limits.....	102

List of Figures

Figure D1.1	Ontario's Internal Zones and External Interconnections.....	87
Figure D1.2.1	Historical Flow Distribution – EWTE/EWTW, FN/FS and CLAN/CLAS Interfaces	89
Figure D1.2.2	Historical Flow Distribution – BLIP/NBLIP, QFW and FETT Interfaces.....	91
Figure D1.2.3	Historical Flow Distribution – Lake Erie Circulation	95

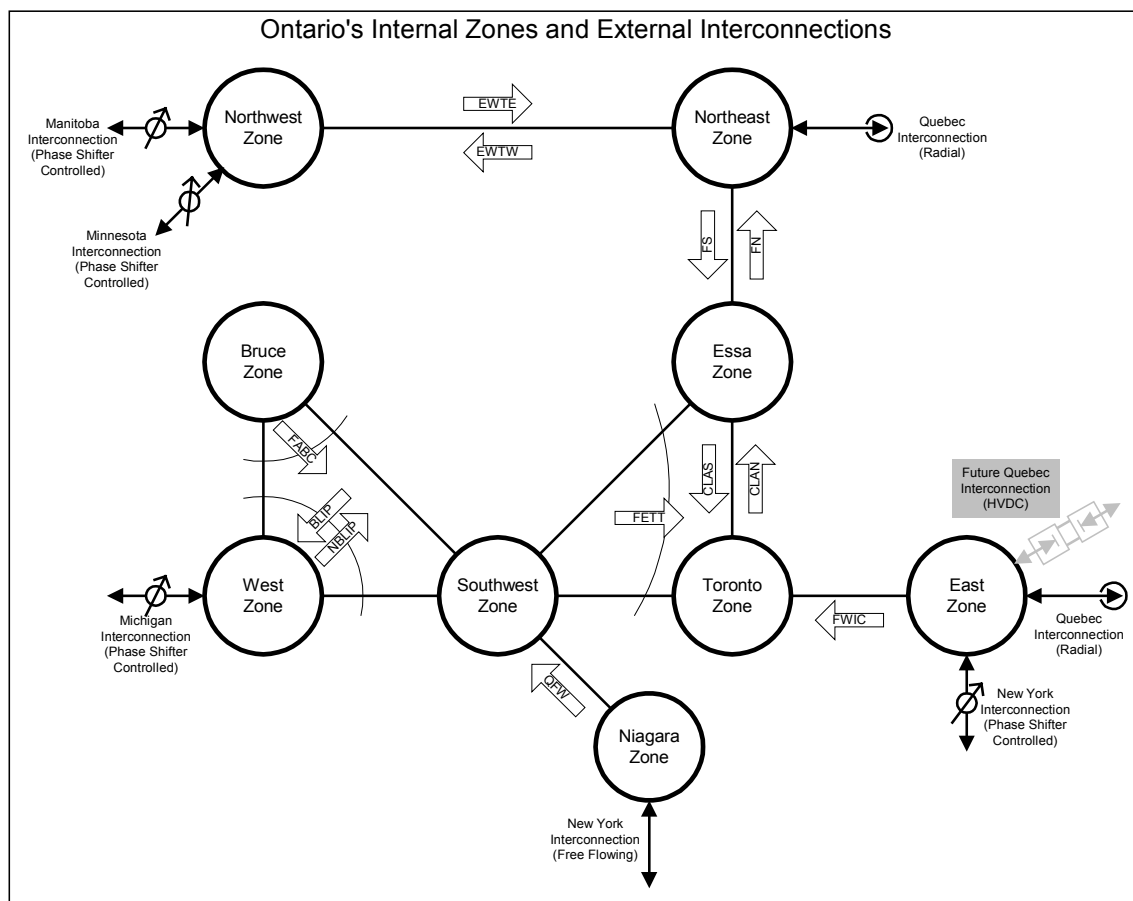
This appendix contains, in Appendix D1, a description of the Ontario transmission system followed, in Appendix D2 and D3, by Ontario's Interface and Interconnection Definitions and Limits.

1.0 Transmission System Description

1.1 Transmission System Interfaces

There are eight major interfaces in the Ontario transmission system, which will be accounted for in this study, as illustrated in Figure D1.1.

Figure D1.1 Ontario's Internal Zones and External Interconnections



Interface Definitions

Interface definitions are formed by grouping one or more lines for the purpose of measuring their combined flow and enforcing a power flow limit or as it is more commonly called an interface limit. Interface limits are directional and interfaces may have limits imposed in one or both directions. Appendix D2.1 shows the major interface definitions used in Ontario. Notice that for each individual transmission element included in an interface definition both the positive direction of power flow and measurement point (e.g. which end of a transmission line the power flow is measured at) are specified.

Interface Capability Limits

Appendix D2.2 shows the base limits for the major interfaces that correspond to the definitions in Appendix D2.1; only normal system (all transmission elements in-service) limits are shown. Note that some limits are simply constants (e.g. BLIP) and others are more complicated and may depend on parameters such as specific generator unit statuses, other flows, primary demand, etc. (e.g. NBLIP, FETT, FABC). In cases where interface limits are based on thermal capability, separate ratings are shown for summer and winter conditions.

1.2 Interface Characteristics

The EWTE/EWTW Interface

The East – West Transfer East (EWTE) and East – West Transfer West (EWTW) flows are functionally related to the power flows between Ontario and Manitoba (OMTE/OMTW etc.). In this relationship, the Ontario – Manitoba Transfer East (OMTE)/Ontario – Manitoba Transfer West (OMTW) flows can be generally thought of as the independent variables as they are under phase shifter control.

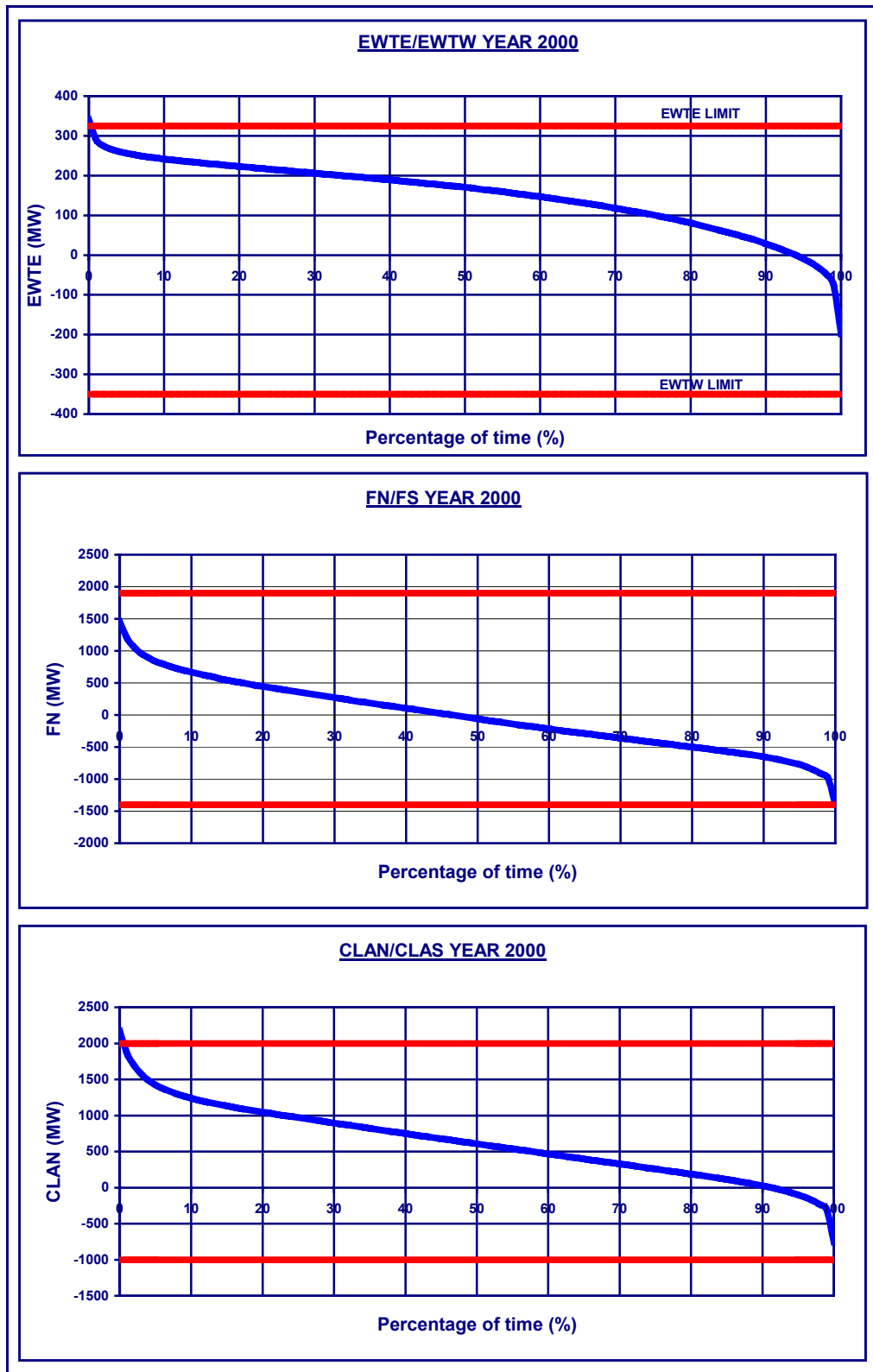
The maximum limits on the East – West tie are 325 MW to the east and 350 MW to the west. The EWTE and EWTW interfaces are constrained by stability limitations. A sample of historical flow distribution on the East West Interface is shown in the Figure D1.2.1.

The FN/FS Interface

The Flow South (FS) limit is 1,400 MW and the Flow North (FN) limit is 1,900 MW. The Flow North and Flow South interfaces are constrained by voltage and stability limits respectively. A sample of historical flow distribution on the Flow North / South interface is shown in the Figure D1.2.1.

The CLAN/CLAS Interface

The Claireville North (CLAN) limit is 2,000 MW and the Claireville South (CLAS) limit is 1,000 MW. A sample of historical flow distribution on the CLAN/CLAS interface is shown in the Figure D1.2.1.

Figure D1.2.1 Historical Flow Distribution – EWTE/EWTW, FN/FS and CLAN/CLAS Interfaces

The FABC Interface

The Flow Away From Bruce Complex (FABC) limit is a functional relationship with a number of other system parameters. With only a total of four Bruce units available (the other four are on indefinite outage) the FABC limit is high enough that it is never limiting. The FABC limit can also be improved through the use of generation rejection of Bruce units.

The BLIP/NBLIP Interface

The Buchanan Longwood Input (BLIP) interface is limited to 3,500 MW to the west due to stability limitations. The Negative Buchanan Longwood Input (NBLIP) interface limit is a function of a variety of parameters. Normally the limit is near its high end of about 1,500 MW; the interface is typically constrained by voltage limitations. A sample of historical flow distribution on the BLIP interface is shown in the Figure D1.2.2.

The QFW Interface

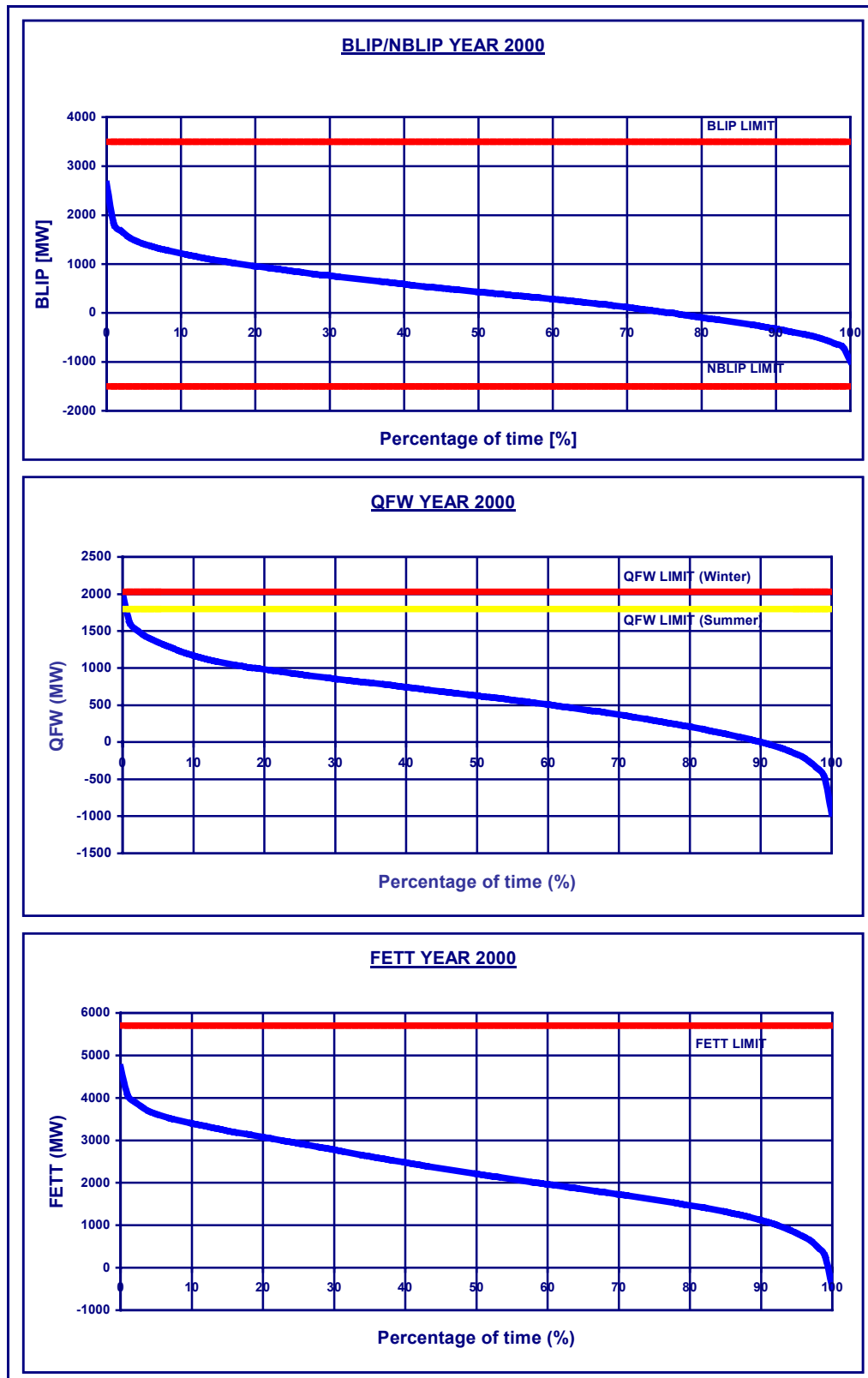
The Queenston Flow West (QFW) interface is limited to 2,030 MW for flows to the west in the winter. In the summer, the limit is 1,800 MW to the west. This interface is constrained by thermal limitations. There is no limit specified for flows to the east, as the level of flows expected in that direction will not cause system concerns. A sample of historical flow distribution on the QFW interface is shown in the Figure D1.2.2.

The FETT Interface

The Flow East Towards Toronto (FETT) interface limit is a function of a variety of parameters. Normally the limit is near its high end of about 5,700 MW. The interface is constrained by a combination of stability and thermal limits. There is no limit specified for flows to the west, as the current level of flows expected in that direction will not cause system concerns. A sample of historical flow distribution on the FETT interface is shown in the Figure D1.2.2.

The FWIC Interface

The Flow West into Cherrywood (FWIC) interface does not have a pre-defined limit. It is included in this study to provide a boundary for the creation of the East Zone to allow for specific forecasts for this region for such parameters as economic conditions for load growth, total resources, etc.

Figure D1.2.2 Historical Flow Distribution – BLIP/NBLIP, QFW and FETT Interfaces

1.3 Transmission System Zones

The Ontario transmission system has been divided into nine zones to facilitate the study. Zonal boundaries have been chosen to correspond with the interface definitions in Appendix D2.1.

Northwest Zone Characteristics

- The total resources generally exceed the zone peak demand.
- The generation is mainly hydroelectric with some coal
- The zone is externally connected to the Manitoba and Minnesota systems.
- The 230 kV Manitoba interconnections are under phase shifter control. The Manitoba 115 kV interconnection is radial. The Minnesota 115 kV interconnection is under phase shifter control.
- To comply with NPCC and MAPP (Mid Continent Area Power Pool) system security criteria, the IMO is committed to implementing enhanced security criteria for the operation of this zone. These criteria will respect double-element contingencies during fair weather conditions. Currently, work is underway to develop mitigating measures for the implementation of these criteria. In order to ensure the reliability of the IMO-controlled grid in the Northwest, the enhanced security criteria will be implemented in stages when the mitigating measures are developed for the different recognized contingencies. It is expected that the enhanced security criteria will not be fully implemented until sometime in 2002 or 2003.

The application of these criteria for the operation of the Northwest zone is expected to impact the operation of the Northeast zone. Therefore, the security criteria for the Northeast will also be reviewed.

Northeast Zone Characteristics

- The total resources generally exceed the zone peak demand.
- The generation is mainly hydroelectric with some cogeneration.
- The zone is externally connected to the Quebec grid.
- The interconnection with Quebec is radial.

Essa Zone Characteristics

- The total resources are much less than the zone peak demand.
- The generation is totally hydroelectric.
- For analytical purposes, Des Joachims generation and 115 kV load, which is physically located in the East zone, has been modeled to be part of the Essa zone. The Essa zone is the primary point of receipt of Des Joachims generation.
- There are no external interconnections.

East Zone Characteristics

- The total resources exceed the zone peak demand.
- The generation is a mix of nuclear, hydroelectric, oil, and gas.

- The zone is externally connected to the Quebec grid.
- The existing interconnection with Quebec is radial. The new interconnection with Quebec will be High Voltage Direct Current (HVDC) transmission. This new interconnection is expected to go in-service in May 2003.
- The zone is also externally connected to the St. Lawrence interface with New York via phase shifter control

Toronto Zone Characteristics

- The total resources are much less than the zone peak demand.
- The generation is mostly nuclear and coal.
- There are no external interconnections.

Bruce Zone Characteristics

- The total resources are much greater than the zone peak demand.
- The generation is mostly nuclear.
- There are no external interconnections.

Southwest Zone Characteristics

- The total resources are well balanced with the zone peak demand.
- The generation is mostly coal.
- There are no external interconnections.

West Zone Characteristics

- The total resources are slightly less than the zone peak demand.
- The generation is mostly coal.
- The interconnection with Michigan is expected to be under phase shifter control by 2002.

Niagara Zone Characteristics

- The total resources are much higher than the zone peak demand.
- The generation is mostly hydroelectric.
- There is a free-flowing interconnection with New York.

1.4 Transmission System Interconnection Capabilities and External Markets

The term interconnection is used to describe interfaces that join Ontario to other (external) control areas.

Ontario has interconnections with Manitoba, Minnesota, Quebec, Michigan, and New York.

Interconnection Definitions

Interconnection definitions are shown in Appendix D3.1.

Interconnection Flow Limits

Interconnection flow limits are shown in Appendix D3.2.

Interconnection Characteristics

All of Ontario's non-radial interconnections are or will be under phase-shifter control, except for New York-Niagara. The new proposed 1,250 MW interconnection between Ottawa and Quebec will be High Voltage Direct Current (HVDC) transmission.

The total transfer capability from Ontario to Michigan and New York depends on the distribution of load and generation across the interconnection. At best, the total transfer is the sum of the two capabilities. At worst, the total transfer is the minimum of either the New York (St. Lawrence plus Niagara) or Michigan transfer capability.

The Ontario – Manitoba Interconnection

The Ontario – Manitoba Transfer East (OMTE) and Ontario – Manitoba Transfer West (OMTW) limits are both 288 MW in summertime, 300 MW in wintertime and are constrained by stability and thermal limitations. However, with the Whiteshell T8 transformer out of service-forced in Manitoba until January 30, 2002, the OMTE and OMTW limits are 163 MW in the summertime and 190 MW in the wintertime.

The Ontario – Manitoba 115 kV interconnection limits are 55 MW for flows into Ontario in the summertime and 69 MW for flows into Ontario in the wintertime.

The Ontario – Minnesota Interconnection

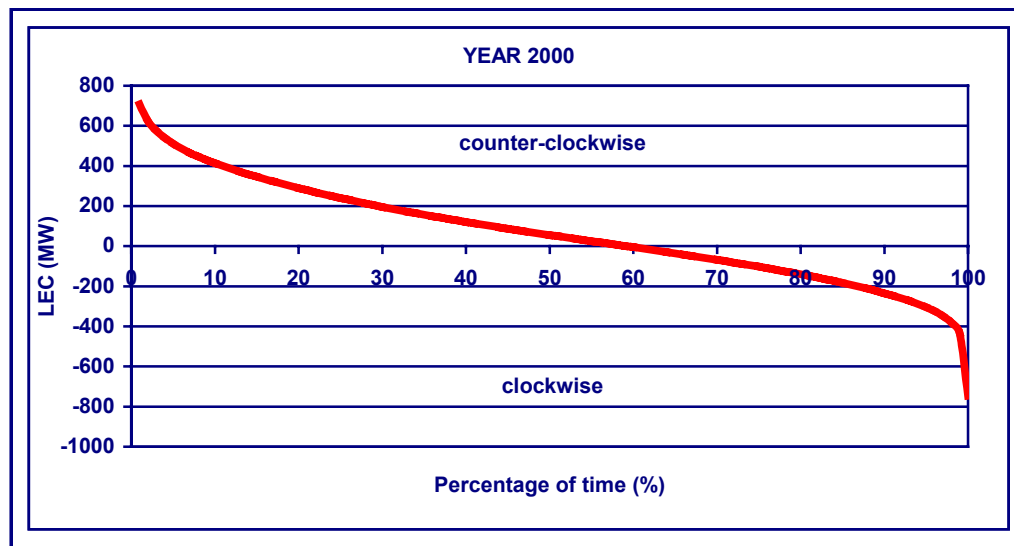
The Minnesota Power Flow North (MPFN) and Minnesota Power Flow South (MPFS) limits are 100 and 150 MW respectively and are constrained by stability and thermal limitations.

The Ontario – Michigan Interconnection

The Michigan interconnection is constrained by thermal limitations.

New phase shifters installed on the Ontario – Michigan interconnection are expected to be operational before 2002. The purpose of the new phase shifters is to control a loop flow or parallel path flow, called Lake Erie Circulation (LEC). LEC occurs naturally through a combination of transmission system impedance with interconnection-wide load/generation dispatch; it is measured as an unscheduled flow across the points of interconnection with New York, at Niagara Falls, and with Michigan. Much of the time, LEC enters Ontario at the New York-Niagara interconnection and exits Ontario at the Michigan interconnection. LEC flows also appear on and aggravate the BLIP and QFW interfaces as they are in a direct series path. The phase shifters are expected to control approximately 600 MW of LEC in either direction. Therefore, it is expected that the incidence of constrained operation of QFW interface will be greatly reduced. A sample of historical flow distribution for LEC is shown in the Figure D1.2.3.

With the phase shifters in-service, the Operating limits for the Michigan interconnection will change from their present values. During the winter months, the limits will be 1,750 MW for flows into Ontario and 2,700 MW for flows out of Ontario. During the summer, the limits will be 1,650 MW for flows into Ontario and 2,450 MW for flows out of Ontario.

Figure D1.2.3 Historical Flow Distribution – Lake Erie Circulation**The Ontario – New York-Niagara Interconnection (60 Hz and 25 Hz)**

The New York-Niagara interconnection, in the winter, is limited to 1,650 MW for flows into Ontario and 2,100 MW for flows out of Ontario. In the summer, the limit is 1,400 MW for flows into Ontario and 2,100 MW for flows out of Ontario. The interconnection is constrained by thermal limitations in the winter and summer.

The QFW interface is in series with the New York-Niagara interconnection. All flows entering Ontario on the NY Niagara interconnection will also appear on the QFW interface; this includes purchases and parallel path flows. Based on past experience and studies, the QFW interface always hits its limit before the limit is reached on the NY Niagara interconnection for flows entering Ontario; as a result, the capability of the NY Niagara interconnection is never fully utilized.

Typically, when QFW hits its limit of 1,800 MW under summer conditions, the flow across the NY Niagara interconnection is 1,100 MW (its limit is 1,400 MW). Similarly, when QFW hits its limit of 2,030 MW under winter conditions, flow across the NY Niagara interconnection is 1,330 MW (its limit is 1,650 MW).

The Ontario – New York-St. Lawrence Interconnection

The limit on this interconnection is 400 MW for flows into or out of Ontario. The interconnection is constrained by thermal limitations and is under the control of phase shifters.

The Ontario – Quebec-North Interconnection

The Quebec-North interconnection is thermally limited to 78 MW under winter conditions and 64 MW under summer conditions, for flows into Ontario from radial generation in Quebec. For flows out of Ontario, the limit is 80 MW. This is simply based on the maximum amount of radial load available to be supplied in Quebec.

The Ontario – Quebec-South Interconnection

The Quebec South interconnection is limited to 1,328 MW for flows into Ontario due to stability limitations and available radial generation. For flows out of Ontario the limits, due to stability and thermal limitations, are 432 MW for the summer and 452 MW for the winter.

The HVDC interconnection will allow flows up to 1,250 MW in and out of Ontario.

2.0 Definitions and Limits of Ontario's Interfaces

2.1 Definitions of Ontario's Interfaces

(* signifies the measurement point)

Buchanan Longwood Input (BLIP) Interface consists of the following circuits:

B562L	Bruce A to Longwood* 500 kV
B563L	Bruce B to Longwood* 500 kV
N582L	Nanticoke to Longwood* 500 kV
D4W	Detweiler to Buchanan* 230 kV
D5W	Detweiler to Buchanan* 230 kV
M31W	Middleport to Buchanan* 230 kV
M32W	Middleport to Buchanan* 230 kV
M33W	Middleport to Buchanan* 230 kV

Negative Buchanan Longwood Input (NBLIP) Interface consists of the following circuits:

B562L	Longwood* to Bruce A 500 kV
B563L	Longwood* to Bruce B 500 kV
N582L	Longwood* to Nanticoke 500 kV
D4W	Buchanan* to Detweiler 230 kV
D5W	Buchanan* to Detweiler 230 kV
M31W	Buchanan* to Middleport 230 kV
M32W	Buchanan* to Middleport 230 kV
M33W	Buchanan* to Middleport 230 kV

Queenston Flow West (QFW) Interface consists of the following circuits:

Q23BM	Beck2* to Burlington and Middleport (Neale Junction) 230 kV
Q25BM	Beck2* to Burlington and Middleport (Neale Junction) 230 kV
Q24HM	Beck2* to Hamilton and Middleport (Hannon Junction) 230 kV
Q29HM	Beck2* to Hamilton and Middleport (Hannon Junction) 230 kV
Q30M	Beck 2 (Allanburg Junction*) to Middleport 230 kV

Flow East To Toronto (FETT) Interface consists of the following circuits:

B560V	Bruce A to Claireville* 500 kV
M570V	Milton to Claireville* 500 kV
M571V	Milton to Claireville* 500 kV
V586M	Middleport to Claireville* 500 kV
R14T	Trafalgar* to Richview 230 kV
R17T	Trafalgar* to Richview 230 kV
R19T	Trafalgar* to Richview 230 kV
R21T	Trafalgar* to Richview 230 kV
E8V	Orangeville to Essa* 230 kV
E9V	Orangeville to Essa* 230 kV

Flow North (FN) and Interface consists of the following circuits:

X503E Essa* to Hanmer 500 kV
X504E Essa* to Hanmer 500 kV
D5H Des Joachims* to Holden 230 kV

Flow South (FS) Interface consists of the following circuits:

X503E Hanmer to Essa* 500 kV
X504E Hanmer to Essa* 500 kV
D5H Holden to Des Joachims* 230 kV

East – West Transfer West (EWTW) Interface consists of the following circuits:

W21M Wawa* to Marathon 230 kV
W22M Wawa* to Marathon 230 kV

East – West Transfer East (EWTE) Interface consists of the following circuits:

W21M Marathon to Wawa* 230 kV
W22M Marathon to Wawa* 230 kV

Claireville North (CLAN) Interface consists of the following circuits:

E510V Claireville* to ESSA 500 kV
E511V Claireville* to ESSA 500 kV
B82V Claireville* to Brown Hill 230 kV
B83V Claireville* to Brown Hill 230 kV

Claireville South (CLAS) Interface consists of the following circuits:

E510V ESSA to Claireville* 500 kV
E511V ESSA to Claireville* 500 kV
B82V Brown Hill to Claireville* 230 kV
B83V Brown Hill to Claireville* 230 kV

Flow Away from Bruce Complex (FABC) Interface consists of the following circuits:

B560V Bruce* to Claireville 500 kV
B561M Bruce* to Milton 500 kV
B562L Bruce* to Longwood 500 kV
B563L Bruce* to Longwood 500 kV
B4V Bruce* to Orangeville 230 kV
B5V Bruce* to Orangeville 230 kV
B22D Bruce* to Detweiler 230 kV
B23D Bruce* to Detweiler 230 kV
B27S Bruce* to Owen Sound 230 kV
B28S Bruce* to Owen Sound 230 kV

Flow West Into Cherrywood (FWIC) Interface consists of the following circuits:

B540C Bowmanville to Cherrywood* 500 kV
B541C Bowmanville to Cherrywood* 500 kV
B542C Bowmanville to Cherrywood* 500 kV
B543C Bowmanville to Cherrywood* 500 kV
P15C Dobbin to Cherrywood* 230 kV
C28C Chat Falls to Cherrywood* 230 kV
H24C Havelock to Cherrywood* 230 kV
H26C Havelock to Cherrywood* 230 kV

M29C Merivale to Cherrywood* 230 kV
B23C Belleville to Cherrywood* 230 kV

2.2 Limits of Ontario's Interfaces

The Ontario major interfaces base limits, for all elements in service are shown in the Table D2.1. Detailed information on these limits is available by request via the IMO Help Centre.

Table D2.1 Ontario's Interface Base Limits

Interface	Operating Security Limits (MW)
BLIP	3,500
NBLIP	1,500
QFW	1,800 Summer (S), 2,030 Winter (W)
FABC	5,200, normally not limiting
FETT	5,700, 5,500 (S) ⁽¹⁾ , 5,300 (S) ⁽²⁾
CLAN	2,000
CLAS	1,000
FN	1,900
FS	1,400
E-W	325 East, 350 West

Summer Limits apply from May 1 to October 31. Winter Limits apply from November 1 to April 30.

(1) Limit is used if the summer primary demand is between 22,001 and 22,600 MW.

(2) Limit is used if the summer primary demand is between 22,601 and 25,000 MW.

3.0 Definitions and Limits of Ontario's Interconnections

3.1 Definitions of Ontario's Interconnections

The Ontario – Manitoba Interconnection

K21W	Kenora 230 kV to Whiteshell 115 kV including combination voltage regulator and phase shifting transformer bank T7 at Whiteshell,
K22W	Kenora 230 kV to Whiteshell 115 kV including combination voltage regulator and phase shifting transformer bank T8 at Whiteshell,
SK1	Rabbit Lake 115 kV to Seven Sisters 115 kV including an in-line voltage regulating transformer at Seven Sisters (radial operation from Manitoba to Ontario only).

Ontario – Manitoba Transfer West (OMTW) consists of the following circuits:

K21W	Kenora* 230 kV to Whiteshell 230 kV
K22W	Kenora* 230 kV to Whiteshell 230 kV

Ontario – Manitoba Transfer East (OMTE) consists of the following circuits:

K21W	Whiteshell 230 kV to Kenora* 230 kV
K22W	Whiteshell 230 kV to Kenora* 230 kV

The Ontario – Minnesota interconnection

F3M	Fort Frances 115 kV to International Falls 115 kV including two phase shifting transformers operated in series, T10 and T11, located at International Falls.
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Minnesota Power Flow North (MPFN) consists of the following circuit:

F3M	International Falls 115 kV to Fort Frances* 115 kV
-----	--

Minnesota Power Flow South (MPFS) consists of the following circuit:

F3M	Fort Frances* 115 kV to International Falls 115 kV
-----	--

The Ontario – Quebec North interconnection consists of the following circuits:

D4Z	Dymond* to Rapide Des Iles 115 kV,
H4Z	Holden* to Kipawa 115 kV,

The Ontario – Quebec South interconnection consists of the following circuits:

X2Y	Chenau to Bryson 115 kV,
Q4C	Chats Falls to Quoyon 230 kV,
P33C	Chats Falls to Pagan 230 kV,
H9A	Hawthorne to Masson 115 kV,
D5A	Hawthorne to Masson 230 kV / Outaouais 325 kV,
B5D	St. Isidore to Beauharnois 230 kV,
B31L	St. Lawrence to Beauharnois 230 kV.

The Ontario – Michigan Interconnection consists of the following circuits:

B3N	Scott* 230 kV to Bunce Creek 120 kV, including in-line autotransformer and phase shifter.
L4D	Lambton* 230 kV to St. Clair 345 kV, including two autotransformers in parallel and phase shifter.

L51D Lambton* 230 kV to St. Clair 345 kV, including in-line autotransformer and phase shifter.

J5D Keith* 230 kV to Waterman 230 kV, including in-line combination voltage regulator and phase shifter SR5.

The Ontario – New York Interconnection at Niagara consists of the following 60 Hz circuits to the New York Power Authority (NYPA), and Niagara Mohawk (NiaMo):

BP76 Beck2 230 kV to Packard 230 kV (NiaMo), including in-line voltage regulating transformer R76,

PA27 Beck2 230 kV to Niagara Moses 230 kV (NYPA), including in-line voltage regulating transformer R27,

PA301 Beck2 230 kV to Niagara Moses 345 kV (NYPA), including in-line 230 to 345 kV autotransformers T301,

PA302 Beck2 230 kV to Niagara Moses 345 kV (NYPA), including in-line 230 to 345 kV autotransformers T302,

BL104 Beck1 115 kV to Lockport 115 kV (NiaMo),

The Ontario – New York Interconnection at Niagara consists of the following 25 Hz circuits to the Niagara Mohawk (NiaMo):

BSC105 Beck1 115 kV to Harper 69 kV (NiaMo), including an in-line 115 to 69 kV transformer at Parks TS,

BSH106 Beck G7 to Harper 69 kV (NiaMo).

The Ontario – New York Interconnection at St. Lawrence consists of the following 60 Hz circuits to the New York Power Authority (NYPA):

L33P St. Lawrence 230 kV to FDR Moses 230 kV (NYPA) including in-line voltage regulating transformer R33 and in-line phase shifting transformer PS33,

L34P St. Lawrence 230 kV to FDR Moses 230 kV (NYPA) including in-line combination voltage regulator and phase shifting transformer PSR34.

3.2 Flow Limits of Ontario's Interconnections

The Ontario interconnection flow limits, for all elements in service are shown in the Table D3.1. The flow limit is the lesser value of either the operating limit or the transfer capability of an interconnection. In some cases, the operating limit and transfer capability of an interconnection may be the same value.

Table D3.1 Ontario's Interconnection Limits

Interconnection	Limit - Flows Out of Ontario MW	Limit - Flows Into Ontario MW
Manitoba – Winter*	300	369
Manitoba – Summer*	288	343
Minnesota ⁽³⁾	150	100
Quebec North – Winter*	80	78
Quebec North – Summer*	80	64
Quebec South - Winter*	452	1,328
Quebec South - Summer*	432	1,328
New York St. Lawrence	400	400
New York Niagara (60 Hz and 25 Hz) – Winter* ⁽¹⁾	2,100	1,650
New York Niagara (60 Hz and 25 Hz) – Summer* ⁽¹⁾	2,100	1,400
Michigan – Winter* ^(2,3)	2,700	1,750
Michigan – Summer* ^(2,3)	2,450	1,650

* Summer Limits apply from May 1 to October 31. Winter Limits apply from November 1 to April 30.

(1) Limits are based on thermal ratings and 75% of pre-load. Summer limits are based on 0-4 km/hr wind speed and 30 Deg.C ambient temperature. Winter limits are based on 0-4 km/hr wind speed and 10 Deg.C ambient temperature.

(2) Limits are based on thermal ratings and 75% of pre-load. Summer limits are based on 0-4 km/hr wind speed and 35 Deg.C ambient temperature. Winter limits are based on 0-4 km/hr wind speed and 10 Deg.C ambient temperature.

(3) For day to day operations of the interconnection, limits are based on ambient conditions such as wind speed, temperature and pre-loads.