Independent Electricity Market Operator

18-Month Outlook:

An Assessment of the Adequacy of the Ontario Electricity System

From April 2001 to September 2002

April 20, 2001

Independent Electricity Market Operator

Executive Summary

This report presents an assessment of the adequacy of resources and transmission for the Ontario electricity system for the 18-month period from April, 2001 through September, 2002. This assessment is based on a forecast of electricity demand and available supply combined with current information on the configuration and capability of the transmission system. The most recent known outage plans of generators and transmitters are incorporated in the assessment.

The adequacy of supply is assessed based upon ensuring that sufficient resources are available to meet the forecast demand after satisfying minimum reserve requirements established by the Northeast Power Coordinating Council (NPCC). The adequacy of transmission capability is assessed based upon ensuring sufficient transmission capability exists to serve demand in conformance with NPCC criteria related to system security.

The summer peak for 2001 is forecast to be 22,333 MW based on the assumption of normal weather. For 2002, the normal weather winter peak is forecast to be 23,731 MW and the summer peak is forecast to be 22,611 MW. The load forecast uncertainty range for these peak values is 740 MW to 960 MW.

The resource adequacy assessment indicates that resources available to supply the forecast Ontario demand meet or exceed the specified reserve margin requirements for the entire time period 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. The forecast Loss of Load Expectation for 2001 and 2002 is well within the Loss of Load Expectation requirement of one day in ten years as stipulated by NPCC.

The transmission outage plan submitted to the IMO has been reviewed for system impacts. Results of this assessment indicate that the transmission system is adequate to supply loads under all forecast conditions provided reactive power support for the Toronto and Windsor areas is maintained. Opportunities to coordinate transmission, generation and interconnection outages will be identified to equipment owners as necessary to minimize supply constraints.

Caution and Disclaimer

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1.0 Introduction

The Ontario Electricity Market Rules (Chapter 5) require that the Independent Electricity Market Operator (IMO) provide forecasts and assessments of the adequacy of the existing and committed resources and transmission facilities after market opening. A condition of the Transitional License for the IMO (Section 18.1) requires the IMO to monitor the state of electricity demand and available supply in Ontario and to report its findings to the Minister of Energy, Science and Technology and to the Ontario Energy Board (OEB).

This is the third 18-Month Outlook issued by the IMO; it supercedes the report titled "An Assessment of the Adequacy of the Ontario Electricity System from October 2000 to March 2002", dated November 17, 2000.

This Outlook covers the 18-Month period from April 1, 2001 to September 30, 2002. Its purpose is to advise the Minister of Energy Science and Technology, the Ontario Energy Board and Market Participants of the resource and transmission adequacy of the Ontario electricity system, and to assess potentially adverse conditions that might be avoided through adjustment or coordination of maintenance outage plans for generation and transmission equipment.

Section 2 of this Outlook provides an 18-Month forecast of electricity demand for Ontario. The resources expected to be available during the study period are summarized in Section 3, and an assessment of the adequacy of the resources under the current generation maintenance outage program is presented in Section 4. The transmission system that is expected to be available is described in Section 5 and the current transmission outage plan 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 905-403-6900 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 served by the IMO-controlled grid (e.g. Cornwall Electric).

Section 2.1 describes the process used to forecast electricity demand. Section 2.2 looks at the categories of variables that are used to derive the forecast and briefly discusses their relative impacts. Section 2.3 summarizes the current energy demand forecast, and Section 2.4 summarizes the peak demand forecast. Appendix A contains additional demand forecast details.

2.1 Forecasting Process

The forecast of Ontario electricity demand used in this assessment was produced by the IMO, based on a forecasting system developed by Regional Economic Research Inc. (RER). RER was contracted to help the IMO establish its load forecasting capabilities.

This system utilizes multivariate econometric equations to define the relationships between peak and energy demand and a number of analytical factors or drivers. The drivers that the system includes 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 forecasting system produces the following output:

- a forecast of the 20-minute east and west peak demand, as well as the coincident system peak demand under Normal, Extreme and Mild weather conditions;
- hourly energy demand by region under Normal, Extreme and Mild weather conditions; and,
- load 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. An explanation of Normal weather and the other weather scenarios is contained in Appendix A, Section 1.0.

2.2 Forecast Drivers

The forecast consumption of energy 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 consumption. Generally, electricity consumption is higher during the week than on weekends; as well, there is a pattern determined by the specific day of the workweek. Holidays act much like weekends, in that energy consumption declines on holidays. The reason for this relationship is that industrial load is lower on holidays and weekends as fewer facilities are operating.

Hours of daylight are key in shaping 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 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.

For purposes of this forecast, the weather is not forecasted but "Normal" weather is utilized. Normal weather 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 generated is contained in Appendix A, Section 1.0.

Economic conditions contribute to the growth in both energy and peak demand. To produce a forecast of electricity demand, an economic forecast of various drivers was required. A consensus of five major, publicly available provincial 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. Recent Federal Reserve rate reductions have signaled weakness in the U.S. economy. Expectations are for a "soft landing" or a slowing of growth without slipping into recession. For the U.S., a successful soft landing will be influenced by monetary policy. For Ontario, the greatest concern may be the outlook for the auto sector as it represents the largest single industrial sector in the provincial economy. In terms of the Ontario economy, weaker U.S. growth has and will have significant impacts on Ontario's auto sector, leading to lower production and lower overall economic activity. However, continued business investment and domestic consumption will help offset some of the U.S. impacts on Ontario's economy. Therefore, although growth is expected to slow, the outlook remains positive for Ontario and the economic forecast reflects that.

For the forecast period (2001 to 2002), the Ontario housing stock is expected to average growth of 1.5% per annum and employment is expected to average growth of 2.0%. Table 2.1 presents some of the key Ontario economic drivers that were assumed.

Table 2.1 Ontario Economic Drivers

Year	Ontario Employment		Ontario Housing Starts	
	Thousands	Annual Growth (%)	Thousands	Annual Growth (%)
1995	5,128		31.9	
1996	5,175	0.92	39.5	23.89
1997	5,298	2.37	50.0	26.47
1998	5,476	3.35	50.1	0.23
1999	5,672	3.59	62.9	25.63
2000	5,856	3.23	67.4	7.15
2001 (f)	5,987	2.24	65.8	-2.39
2002 (f)	6,087	1.67	60.6	-7.86

2.3 Forecast of Energy Demand

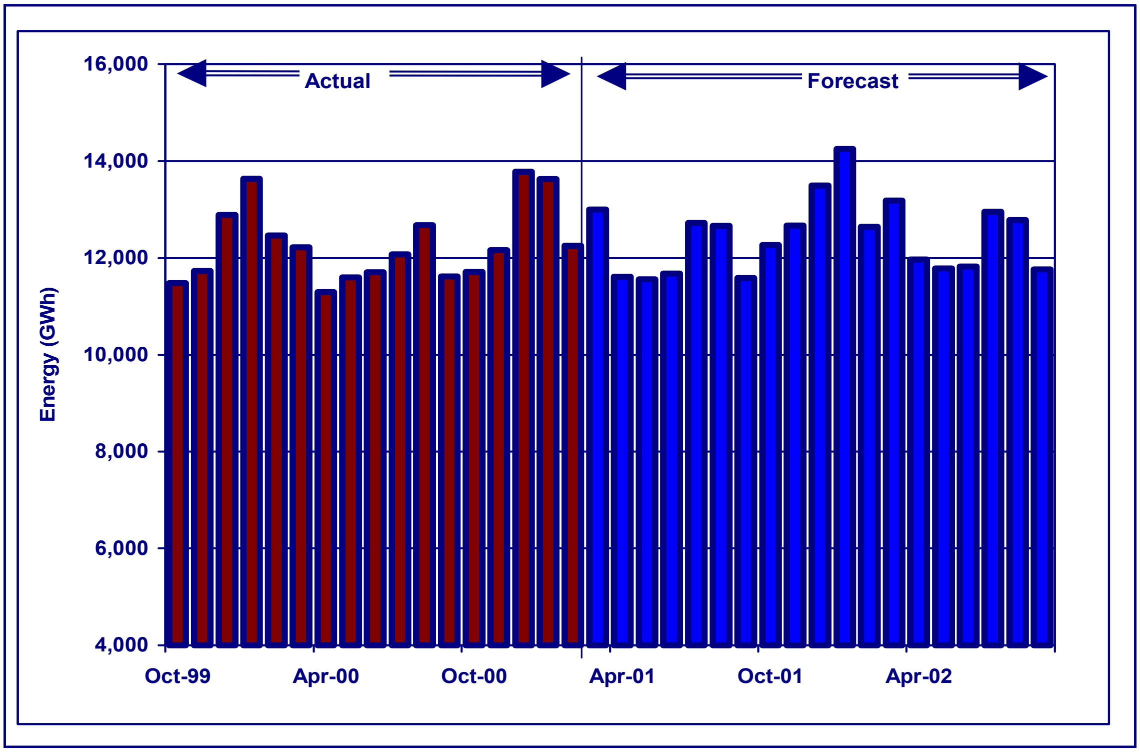
Actual Ontario energy demand has averaged annual growth of 1.6% over the historic period of 1986 to 2000. The predicted energy demand and corresponding growth rates for the time frame 2001 to 2002 are detailed in Table 2.2. Figure 2.1 graphically displays energy demand on a monthly basis. Energy demand is expected to exhibit annual growth of 1.4% in 2001 and 1.5% in 2002. 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 presents summary information at the system level, the load forecast contains hourly detail for all nine transmission zones within the system. A forecast of zonal energy demand is provided in Appendix A, Table A1 and a map of the zones is depicted in Figure A1. Energy demand growth varies across the zones as they are subject to different economic forces.

Table 2.2 Ontario Energy Demand

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	n/a	n/a
2002 (f)	152.1	1.48	n/a	n/a

Figure 2.1 Monthly Ontario Energy Demand – Normal Weather



2.4 Forecast of Peak Demand

Historically, Ontario's electricity peak demand has usually occurred during the winter, in the months of December through 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 the afternoon of early to mid-July. 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 2000 were 23,222 MW and 23,428 MW respectively. The peak for winter 2001 was 22,672 MW.

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 ten times since 1985. Of the remaining six years the winter peak has occurred on the day with the second most extreme weather. The summer peak is less consistent, occurring on the most extreme day only four times since 1985. This is due to summer vacations and plant shutdowns mitigating some of the impact of the extreme weather conditions on peak demand. However, since 1995 the summer peak day has coincided with either the most or second most extreme day with the exception of 1999.

Over the 1986 to 2000 time frame, the actual summer peak demand has averaged growth of 2.3%, much stronger than that of the winter peak demand which has averaged growth of 0.9% over the same time. This is attributable to the increased penetration of air conditioning, along with the switching of heating equipment to natural gas in the residential sector. As well, the trend in peaks has been a product of milder winters and hotter summers experienced over the course of the 1990's.

Based on weekly normalized weather, the system is expected to remain winter peaking throughout the forecast period. Figure 2.2 displays the weekly peak demands over the forecast period. Figure 2.3 compares this weekly peak forecast with the actual and normalized values for the corresponding weeks in 2000. The summer 2001 peak is forecasted to be 22,333 MW. For 2002, the winter peak is expected to be 23,731 MW and the summer peak 22,611 MW. Table 2.3 depicts the summer and winter peaks for both actual and normal weather.

Figure 2.2 Forecast of Weekly 20-Minute Ontario Peak Demand - Normal Weather

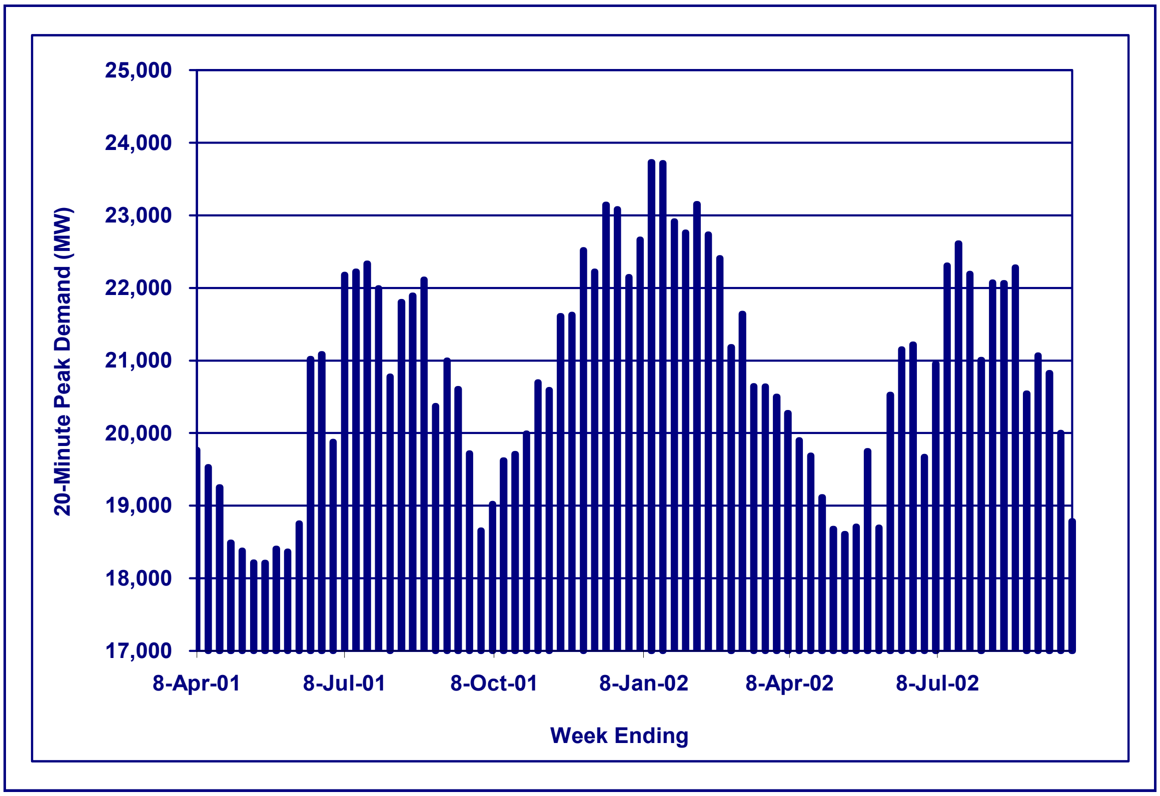


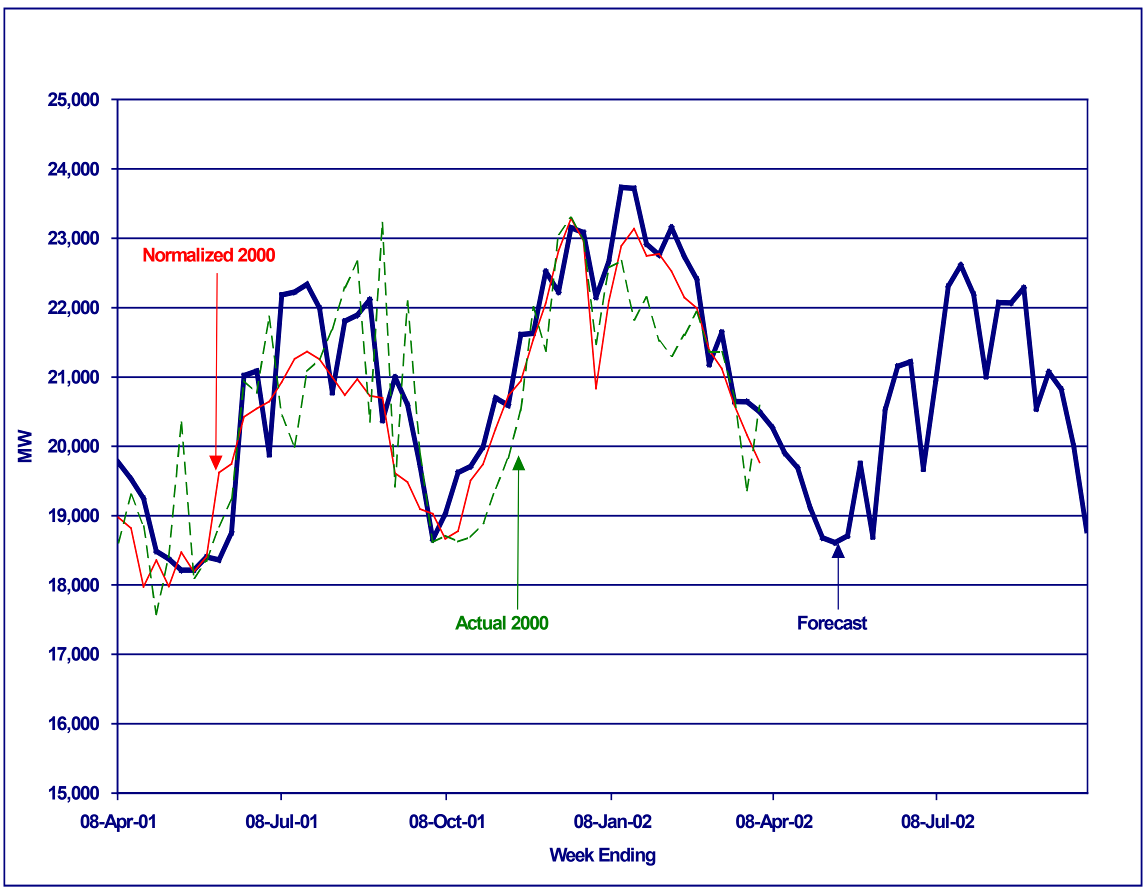
Table 2.3 Ontario Peak Demand

Year	Normal Weather		Actual Weather	
	Winter Peak (MW)	Summer Peak (MW)	Winter Peak (MW)	Summer Peak (MW)
1995	22,121	19,478	22,855	21,770
1996	21,567	19,386	22,321	21,428
1997	21,964	20,074	22,197	21,667
1998	21,960	20,621	22,067	22,443
1999	22,450	20,373	23,308	23,435
2000	23,284	21,438	23,428	23,222
2001 (f)	23,149	22,333		
2002 (f)	23,731	22,611		

Note to Table 2.3:

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).

Figure 2.3 Weekly System Peaks – Forecast 2001-2002, Actual 2000 and 2000 Normalized



3.0 Resources

This section describes the generation resources forecast to be available in the 18-month study period. The information in this Section is as of March 21, 2001.

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, as of March 21, 2001. Section 3.4 provides an overall summary of the total and available resources included in the study.

3.1 Existing 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, wood and waste-fuelled generation, as well as hydroelectric and wind-powered stations. The installations range in size from less than 1 MW to 881 MW resulting in a total capacity of 29,492 MW. Not included in the study are embedded generators which are not managed by Ontario Electricity Financial Corporation (OEFC) or generation not directly serving the IMO-controlled grid. The differences from the installed resources reported in the last 18-Month Outlook, where the total was 29,560 MW, are due to changes in ratings for some coal generating units.

The capacity of installed generation resources does not include Bruce A units, which are currently in laid-up state, but does include the Pickering A units.

All the listed generation is considered available for use in the 18-month period, except for some of 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	3,666	31	<1 - 535
Hydroelectric	7,428	128	<1 - 136
Miscellaneous (wind, waste, wood, etc.)	77	6	1 - 40
Total	29,492	174	<1 - 881

3.2 Long Term External Transactions Outside the Province

Availability of 700 MW of firm capacity and energy from outside Ontario is included in the assessment for the periods of April 1 through November 30, 2001 and February 1 through April 30, 2002. For the period of December 1, 2001 through January 31, 2002, an amount of 650 MW of firm external resources is included. For the remainder of the 18-month interval, 200 MW of firm capacity and energy from external sources is being contracted. No firm sales or other firm purchase contracts have been identified for the study period.

3.3 Potential New Resources

In accordance with the Market Rules, Chapter 4, Section 6, any participant planning a new or modified connection to the IMO-controlled grid must apply to the IMO for approval under the CAA process.

Table 3.2 summarizes potential new generation projects that have been identified to the IMO through the CAA process, as of January 5, 2001 and whose estimated in service date falls in the 18-month interval studied. 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
Agro Sun	Niagara	Gas	88	Q4 - 2001	PA
Enron	West	Gas	219	Q2 - 2001	SIA
Enron	West	Gas	286	Q2 - 2002	SIA
Transalta	West	Gas	491	Q3 - 2002	SIA

Details about the CAA process, the status of all current applicants, 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.

Due to uncertainties with respect to the timing of these projects, or in some cases even whether they will proceed, the IMO has reasonable doubt whether the commissioning of most of the above listed projects will occur within the 18-month time span. To reflect a conservative approach to this uncertainty none of the projects have been included in the present study.

3.4 Summary of Available Resources Assumed in the Study

Table 3.3 shows a snapshot of the available resources assumed in the study, at the time of the winter 2002 peak demand, and summer 2001 and 2002 peak demands. The resource picture has been developed starting from the existing installed generation resources shown in Table 3.1. Then external transactions, described in section 3.2, have been included to obtain the Total Resources. No generation additions have been included in this assessment. Generator deratings, planned generator outages, generation constrained off due to transmission interface limitations and allowances for non-utility and hydroelectric generation production below rated capacity have been subtracted from the Total Resources to obtain the Available Resources.

Table 3.3 Summary of Available Resources Assumed in the Study

Notes	Description \ Year	Summer Peak 2001	Winter Peak 2002	Summer Peak 2002
1	Installed Resources	29,492	29,492	29,492
2	Imports	700	650	200
3	Total Resources	30,192	30,142	29,692
4	Total Reductions in Resources	4,309	3,574	4,557
5	Available Resources	25,883	26,568	25,135

Notes to Table 3.3:

1. Installed Resources: This is the total capacity of the existing installed generation resources in Ontario assumed to be available over the summer and winter peaks in the 18 month time span, 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 serving the IMO-controlled grid.

2. Imports: Represents the amount of external capacity available to Ontario under existing contracts/agreements.

3. Total Resources: This is the sum of lines 1 and 2 above.

4. Total Reductions in Resources: These reductions represent the sum of generator deratings, planned generator outages, generation constrained off due to transmission interface limitations and allowances for non-utility and hydroelectric generation production below rated capacity.

5. Available Resources: This is the difference between lines 3 and 4 above.

4.0 Resource Adequacy 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

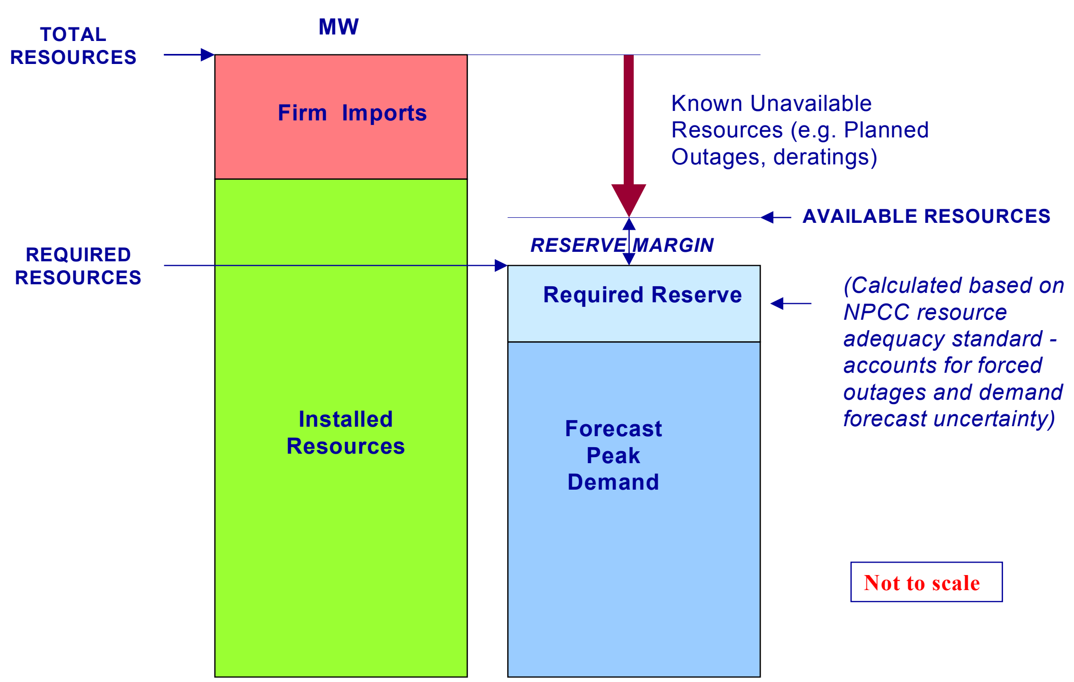
The IMO, as a member of the NPCC, is expected to demonstrate that it can achieve the following resource adequacy standard:

"…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 ".

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



4.1.2 How the Criterion Was Applied

The Required Reserve in MW was calculated 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 the Required Reserve) from the minimum Available Resources. Whenever the Reserve Margin is positive the reliability criterion is met or exceeded (i.e. the Loss of Load Probability, LOLP, is less than or equal to 0.1).

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 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 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.

4.2 Assessment of Resource Adequacy

4.2.1 Forecast Weekly Margins

The forecast Reserve Margin for each week is shown in Figure 4.2. The total reductions to resources are shown in Figure 4.3. Further details and explicit values are provided in Appendix C. Analysis of the forecast Reserve Margins indicate the following:

Most of the forecast Reserve Margins are positive in the forecast period. The estimated Loss of Load Expectations, (LOLE) for both 2001 and 2002 suggest that the Ontario electricity system will be operated at a much lower risk level than required by the NPCC resource adequacy standard. The Loss of Load Expectation is an annual value derived from the individual weekly LOLP values described above.

Reserve margins above required levels indicate that opportunities exist in May and June, 2001, and May, 2002 for additional generator outages.

With one exception, the few weeks with negative Reserve Margins exceeding 500 MW in the study period occur outside seasonal peak demand periods (April 2001, April and September 2002), when external resources are likely to be available, since neighbouring systems are also outside their seasonal peak demand periods. Also, large changes in Reserve Margins often occur in the spring and fall as Ontario generator outage plans shift. The one exception is over the summer peak in 2002, which is easily remedied by a slight shift in a single generation outage. The potential requirement for remedial action will be reviewed early in 2002.

4.2.2 Uncertainties in Forecast Margins

Uncertainties in demands due to weather effects and in generator forced outages have been taken into account in the calculation of the Reserve Margins. Although current economic conditions are reflected in the base demand forecast, uncertainties in the forecast demand due to unforeseen economic growth or decline are not reflected. These factors are not considered to have significant enough impact in such a short timeframe to warrant separate study. Readers are free to make their own assessments by considering that higher demand growth reduces Reserve margins while lower demand growth increases Reserve Margins.

Generating unit forced outage uncertainties in excess of the allowance already included in the assessment can have negative impacts on Reserve Margins. These events can be caused by random unit failures or by unplanned extensions to planned maintenance. In latter case, the IMO has identified periods where outage extension risks exist. In conjunction with these risks, the IMO has identified that sufficient control actions exist to restore Reserve Margins to adequate levels in these periods.

4.2.3 Outage Coordination and Dependence on External Resources

The management of the Ontario load and capacity situation is a continual process, which responds to numerous factors that can affect the adequacy of the Ontario supply situation. The availability of generating units (i.e. requirement for unit outages) and resource imports from other control areas are major factors that significantly impact the supply adequacy. Generator outage plans are developed to balance the need for adequate supply while providing the necessary outage time to ensure continued equipment and staff safety, meet regulatory requirements and to maintain long term equipment reliability. Most outages are planned during the fall and spring periods to take advantage of lower demands and the availability of surplus capacity from other control areas, if needed, to ensure Ontario's supply adequacy. If during the course of time new outages or the duration of scheduled outages change, plans will be developed by the IMO with Market Participants to either re-schedule existing outages and/or acquire additional resources to once again re-establish acceptable levels of adequacy. The above are considered normal planning activities and exclude any emergency control actions that are available to the IMO in day to day operations.

Generators, Transmitters and other market participants are expected to address the coordination of planned outages of their equipment, one with the other, in their bilateral operating agreements. However, the IMO assesses the individual plans of each market participant from an integrated perspective. The results of the IMO's integrated assessment are intended to provide information to participants by identifying opportunities for further coordination or by suggesting changes in timing to mitigate reliability concerns. Positive Reserve Margins indicate periods where additional planned outages or additional exports can be planned. Negative Reserve Margins indicate a potential dependence on external resources and suggest that generation impactive outages should be rescheduled to a more optimal time-period to restore the prescribed risk levels.

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 Ontario summer peak demand periods of July and August, experience has shown that the remainder of the Northeastern systems of Canada and the United States 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. 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. 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.

4.3 Summary

Adequate generation resources exist for the study period. Loss of Load Expectations (LOLE) for 2001 and 2002 are well within the NPCC resource adequacy standard.

In May and June 2001 and May 2002 opportunities exist for additional generator outages.

The few weekly Reserve Margins, which are below required levels, occur mostly outside seasonal peak demand periods, when external resources are likely to be available, as neighbouring systems are also outside their seasonal peak demand periods. The single exception in the summer of 2002 can be managed through a minor generator outage plan adjustment, which should be considered early in 2002.

Sufficient control actions are available to manage uncertainties in demand or resource levels, which might exceed the allowances covered by the Required Reserve.

Figure 4.2 18-Month Forecast of Resource Adequacy

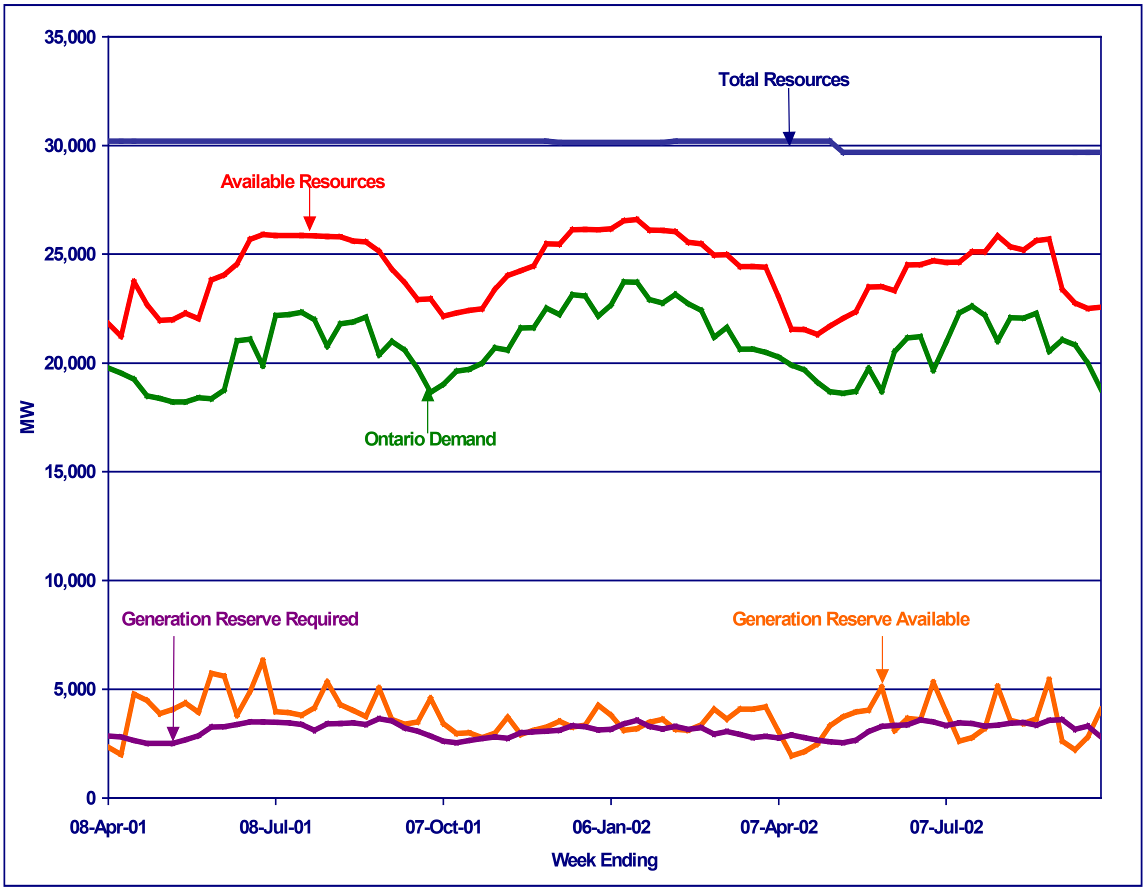
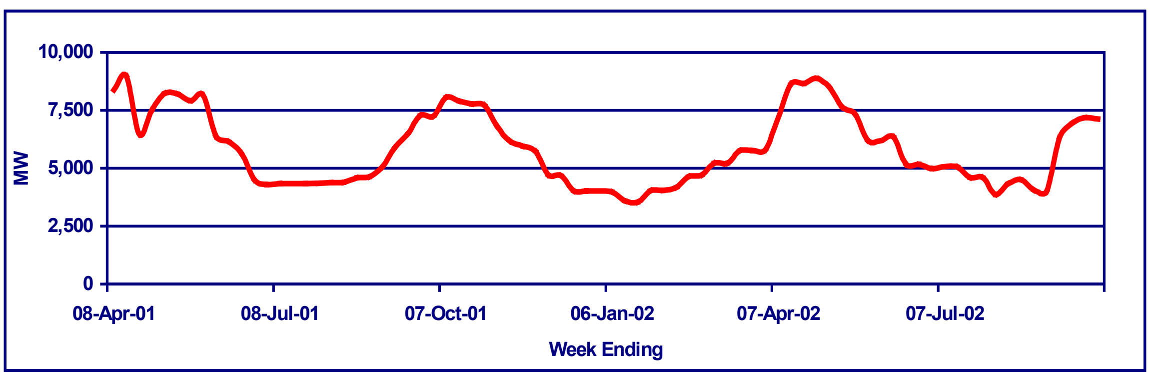


Figure 4.3 Total Reductions in Resources



Note to Figure 4.3:

Total Reductions in Resources represent the sum of generator deratings, planned generator outages, generation constrained off due to transmission interface limitations and allowances for non-utility and hydroelectric generation production below rated capacity.

5.0 The Ontario Electricity System

5.1 Current Configuration of the Transmission System

The existing 500, 230 and 115 kV transmission network is shown in Appendix B.

Figures 5.1 and 5.2 provide a geographic depiction of Ontario's internal transmission zones, major transmission interfaces, and points of interconnection with other jurisdictions. Limits for the interfaces and interconnections are also included in Figure 5.2. The interconnection and interface limits are used to ensure system stability, acceptable pre- and post-contingency voltage levels and/or thermal levels. ***The total Ontario import/export capability is not the arithmetic sum of the individual interconnection flow limits.*** Depending on the availability of generation, the interconnections can carry coincident exports of up to 5,800 MW and coincident imports of up to 3,900 MW. The characteristics of the transmission zones, transfer interfaces and interconnections are described in Appendix D.

5.1.1 Changes/Updates to the Committed Transmission Projects from the Previous Report

Committed transmission projects are summarized in Appendix D, Section D4. The projects were taken from Hydro One's "24 Month Forecast of milestone dates for new BES Facilities" report, also simply referred to as the "milestone report", dated November 22, 2000. The report identified projects in all zones except Bruce, Essa and Niagara.

Although not listed in the milestone report, the modification of the Michigan-Ontario interconnection is near completion. For circuit B3N, a 230 kV, 675 MVA phase shifter (PS) has been installed in Michigan and is currently bypassed from use. For circuit L51D, a 230 kV, 845 MVA phase shifter has been installed in Ontario at the Lambton Thermal Generating Station (TGS), and a 345/230 kV, 1000 MVA autotransformer has been installed in Michigan. Presently, the L51D phase shifter is out of service. However, its operation was restricted to neutral tap operation only. For circuit L4D, the Lambton TGS T7 and T8 345/230 kV autotransformers have been paralleled and are in service (I/S). The remaining 230 kV, 845 MVA phase shifter for circuit L4D has not been installed at Lambton TGS.

All of the above facility installations were completed in June 2000. The L4D phase shifter is expected to be installed by August 2001. The modification of the Ontario-Michigan interconnection will increase the transfer capability between Ontario and Michigan as shown in Appendix D, Table D3.1. The new phase shifting transformers, with an effective phase angle control range of ±40 degrees under full load will provide the capability of controlling Lake Erie Circulation (LEC) by approximately 600 MW in either direction. Details are provided in Appendix D, Section D1.4.

The incorporation of the TransAlta generation project in the West zone is also not listed in the milestone report. The project by itself involves the installation of two new 230 kV breakers, the replacement of four 115 kV breakers, and the retermination of radial 230 kV circuits N6S and L23N at Scott TS. In addition, a 2 km section of 230 kV circuits N21W and N22W has to be upgraded. The expected in-service date of this project is the third quarter of 2002.

Once the TransAlta project is in-service, the subsequent incorporation of the 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 some 230 kV circuits at the Lambton switchyard will be required, to allow the Lambton 230 kV busbar to be operated "split".

The other major committed plan is the addition of a 1,250 MW High Voltage Direct Current (HVDC) interconnection with Quebec in the East transmission zone. The expected in-service date is May 2003. Two 230 kV circuits are required for this project. The circuits will start from the Hawthorne Transformer Station (TS) in Ottawa, run through Gamble Junction, and then cross over the Ottawa River and run to Outaouais Substation in Quebec.

New facilities will be added to 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. In addition, new transmission circuits will be built by Hydro Quebec to improve the security of supply to Outaouais area.

Figure 5.1 Ontario's Internal Transmission Zones

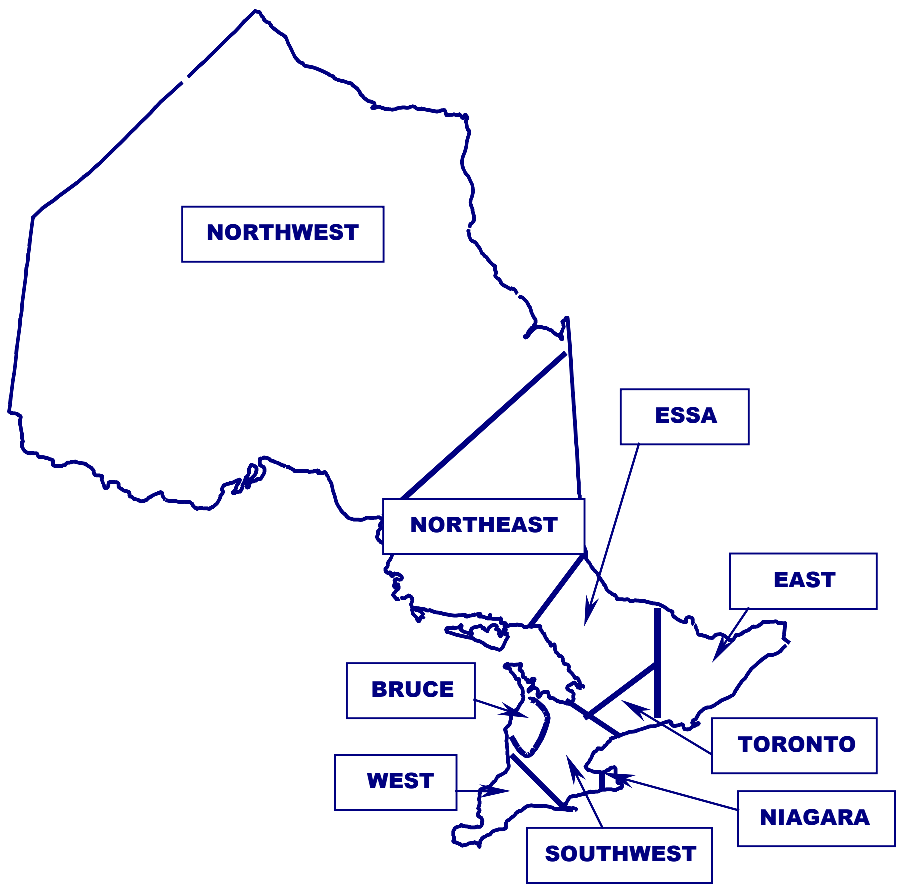
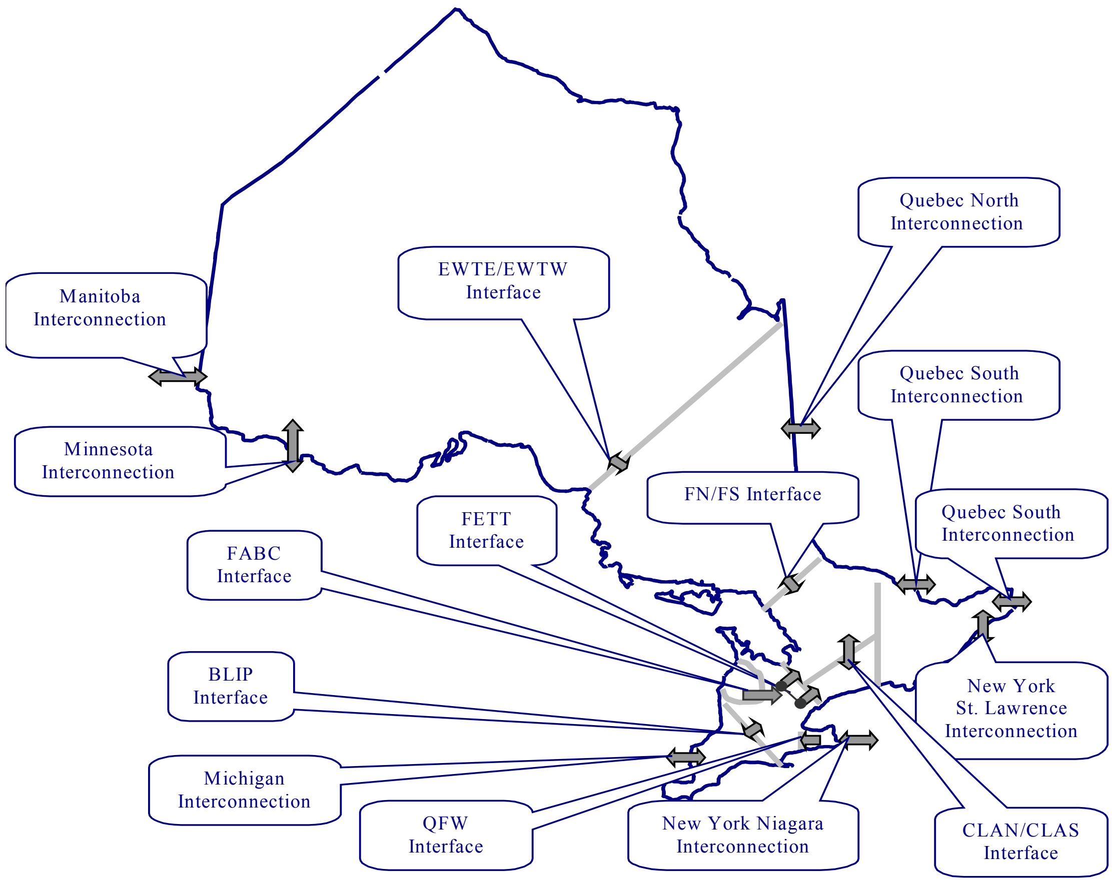


Figure 5.2 Ontario's Significant Internal Transfer Interfaces and Points of Interconnection With Neighbouring Areas



Interconnection	***Flow Limit in MW***
Manitoba	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
Minnesota	100 in, 150 out
Quebec North	64 in, 80 out Summer / 78 in, 80 out Winter
Quebec South	1,328 in, 432 out Summer / 1,328 in, 452 out Winter
New York Niagara (60 Hz and 25 Hz)	1,400 in, 2,100 out Summer / 1,650 in, 2,100 out Winter
New York St. Lawrence	400 in, 400 out
Michigan	Before PS I/S: 1,500 in, 2,350 out Summer / 1,600 in, 2,400 out Winter After PS I/S: 1,650 in, 2,450 out Summer / 1,750 in, 2,700 out Winter
Transmission Transfer Interface	***Base Limit in MW***
East-West Tie East (EWTE)	325
East-West Tie West (EWTW)	350
Flow North (FN)	1,900
Flow South (FS)	1,400
Claireville North (CLAN)	2,000
Claireville South (CLAS)	1,000
Flow Away From the Bruce Complex (FABC)	5,200, normally not limiting
Buchanan Longwood Input (BLIP)	3,500
Negative BLIP (NBLIP)	1,500
Queenston Flow West (QFW)	1,800 Summer / 2000 Winter
Flow East to Toronto (FETT)	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

6.0 Transmission Adequacy Assessment

The principal purpose of this transmission adequacy assessment is to identify any transmission limits of concern in the next 18 months and to highlight transmission outages that should be rescheduled or coordinated with generation outages to mitigate system reliability concerns.

At this time, Hydro One is the largest transmitter in Ontario. On a monthly basis, Hydro One submits to the IMO an 18 month rolling outage plan detailing planned transmission outages. For this Outlook, the Hydro One outage plan submitted on February 19, 2001 was used.

Transmitters and generators are expected to have a mutual interest in developing an ongoing arrangement to coordinate their outage planning activities. The IMO has an obligation to review the integrated plans of generators and transmitters to identify situations that may adversely impact the operation of the system and to notify the affected participants of these impacts.

The scope of the transmission assessment for this report is outlined in Section 6.1. The primary assessment is contained in Section 6.2, while voltage and other concerns that may impact on system operation in the study period are outlined in Sections 6.3 and 6.4. A summary of the adequacy of the transmission system is provided in Section 6.5.

6.1 Planned Transmission Outages

Hydro One's transmission outage plan is shown in Appendix D, Section D5. The outage plan includes outages for transmission facilities with voltage levels of 115 kV and higher and with a duration longer than 5 days. The following items are listed for each outage, with the first and third item having been provided by Hydro One:

1) Description of the outaged transmission element
2) Transmission zone (as defined in Appendix D, Section D1.3 of this report)
3) Start and finish dates, outage type (continuous or otherwise) and recall time,
4) IMO's statement about any reduction in the interconnection flow limits and/or major interface base limits as defined in Appendix D, Sections D2 and D3.

For outages with recall times greater than 36 hours and limits penalized greater than 10%, there is an additional assessment, as required, to indicate the potential for constrained generation, the impact on generation reserve requirements and any local minimum generation requirements.

6.2 Assessment of Transmission Outage Plan

The IMO's assessment of the impact of the transmission outage plan provided by Hydro One is shown in Appendix D (Tables D5.1 to D5.9). In these tables, each element in Hydro One's outage plan is assessed individually by indicating the possible impacts and the reduction in transmission interface and/or interconnection limits.

Outages that may affect interconnection support or generation access to the IMO-controlled grid should be coordinated with the generator owners involved, especially at times when generation reserve margins are below required levels.

In summary, only a few of the planned outages will potentially impact the dispatch of generation. A further analysis of overlapping outages did not result in the identification of any further impacts. The outages with the highest impact are listed below:

Essa Transmission Zone

The Essa 500 kV breaker outages are critical to the Flow North limit. However, the outages are not expected to change the Northeast dispatch requirements at off peak hours.

Niagara Transmission Zone

The Beck 2 K bus outage will constrain off some of the Beck generation.

Northeast Transmission Zone

There are several outages that are critical to the Quebec North interconnection. However, these outages are not expected to be limiting.

Northwest Transmission Zone

The 230 kV K23D circuit outage from April 23, 2001 to May 31, 2001 impacts exports to Manitoba and imports from Minnesota plus the East-West transfer limits. The outage may constrain some Northwest generation. However, given the outage dates, it is not expected to increase generation reserve requirements.

The 115 kV F3M circuit outage from August 21, 2001 to September 3, 2001 results in no exports and imports from Minnesota. The outage may constrain some Northwest generation. However, given the outage dates, it is not expected to increase generation reserve requirements.

6.3 System Voltage Concerns

Low system voltage concerns will limit the generation and transmission outages that can be planned during summer peak demand periods. The various system voltage concerns are described below.

In the Windsor area, load growth is stressing the capability of the existing system under extreme-weather, summer peak conditions, when voltages are expected to be near the low end of the acceptable range. Voltage control is acceptable but may require restrictions on the use of the J5D interconnection for exporting power to Michigan. Planned outages to generating units or transmission circuits in the Windsor and Sarnia area should therefore be avoided during the summer peak period.

Studies conducted for summer peak periods in the Toronto zone have shown that voltage levels will be acceptable but with little or no margin for contingencies. The planned outage of one Pickering B generating unit can be accommodated but system voltages are expected to be at or near their acceptable minimum values, and require the availability of the remaining four Lakeview, three Pickering B and four Darlington units. Planned outages to these units should be scheduled outside the summer peak periods. These studies assumed that all but two Darlington units can supply their designed reactive output capability at rated MW output, and that all other reactive sources and transmission elements in the Toronto zone are available. For summer peak demands above 24,250 MW, voltages in the Toronto zone can be expected to drop 1.5 kV for each additional 100 MW of demand (at 0.9 power factor). This means that pre-contingency actions may be necessary to manage the risk of the loss of an additional large generating unit. The historical, lower-than-rated equipment performance, of some Pickering and Darlington units in providing rated reactive power during hot weather further erodes any available voltage control margins in the area. Restoration of the rated reactive output capability of these units will reduce the stated voltage concerns.

At least one of the two generators at Thunder Bay is required to be in-service, most of the time, to maintain minimum voltages in the area, at times of normal industrial demand.

6.4 Forced Outages

Due to a forced outage, the Whiteshell T8 transformer in Manitoba is currently unavailable until January 30, 2002. This has reduced the transfer capability between Manitoba and Ontario. The outage also reduces the East-West tie capability, in the order of 50 to 100 MW, further reducing dispatching flexibility in the Northwest zone and requiring more coordination in the planning of transmission and generation outages.

6.5 Summary

The transmission outage plan has been reviewed for system impacts. Transmission outages in the Northwest and Niagara zones may or will constrain generation when they proceed. Outages to critical transmission circuits in the Northeast and Essa zones are not expected to be limiting for forecast conditions.

The forced outage of the Whiteshell T8 transformer will adversely impact Ontario Manitoba transfer capability and may at times limit dispatch flexibility in the Northwest zone.

System voltage concerns during times of expected summer peak demands may limit the flexibility for planning outages in the Toronto and Windsor areas. Restoration of the reactive power output capability of Darlington and Pickering units would reduce the stated voltage concerns in the Toronto area.

Voltage concerns in the Thunder Bay area will continue to require reactive support from the rotating reactive resources in the area.

7.0 Overall Findings and Conclusions

An assessment of the adequacy of resources and transmission in the Ontario electricity system has been carried out for the period from April, 2001 through September, 2002. The assessment is based on a forecast of electricity demand and available supply combined with current information on the configuration and capability of the transmission system. The most recent known outage plans of generators and transmitters are incorporated in the assessment.

Adequate generation resources exist for the study period. Loss of Load Expectations (LOLE) for 2001 and 2002 are well within the NPCC resource adequacy standard.

In May and June 2001 and May 2002 there are opportunities for additional generator outages.

The few weekly Reserve Margins, which are substantially below required levels, occur mostly outside seasonal peak demand periods, when external resources are likely to be available, as neighbouring systems are also outside their seasonal peak demand periods. The single exception in the summer of 2002 can be managed through a minor generator outage plan adjustment, which should be considered early in 2002.

Sufficient control actions are available to manage uncertainties in demand or resource levels, which might exceed the allowances covered by the Required Reserve.

Transmission outages in the Northwest and Niagara zones may constrain generation when they proceed. Outages to critical transmission circuits in the Northeast and Essa zones are not expected to be limiting for forecast conditions.

The forced outage of the Whiteshell T8 transformer will adversely impact Ontario Manitoba transfer capability and may at times limit dispatch flexibility in the Northwest zone.

System voltage concerns during times of expected summer peak demands may limit the flexibility for planning outages in the Toronto and Windsor areas. Restoration of the reactive power output capability of Darlington and Pickering units would reduce the stated voltage concerns in the Toronto area.

Voltage concerns in the Thunder Bay area will continue to require reactive support from the rotating reactive resources in the area.

Appendix A – Electricity Demand Forecast

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1.0 Normal Weather

Within each week, the average of the hottest historical days, over the past 30 years, becomes the hottest day in the Normal week. The average of the next hottest historical days becomes the 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.

Table A1 Monthly Zonal Energy Forecast, Normal Weather

Month	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total
	(GWh)									
Jan-01	724	1,159	2,561	749	4,334	541	74	2,442	1,447	14,031
Feb-01	644	1,035	2,286	669	3,869	495	67	2,232	1,300	12,597
Mar-01	670	1,070	2,343	685	3,966	524	70	2,319	1,357	13,004
Apr-01	616	916	2,090	519	3,574	482	63	2,089	1,262	11,611
May-01	607	883	2,074	516	3,547	500	62	2,057	1,317	11,563
Jun-01	592	809	2,120	513	3,548	519	63	2,071	1,445	11,680
Jul-01	587	823	2,342	567	3,919	562	66	2,261	1,600	12,727
Aug-01	626	907	2,299	556	3,848	558	67	2,241	1,564	12,666
Sep-01	597	926	2,082	504	3,484	501	62	2,056	1,374	11,586
Oct-01	661	1,035	2,195	546	3,754	520	64	2,145	1,348	12,268
Nov-01	666	1,058	2,290	569	3,917	516	67	2,221	1,365	12,669
Dec-01	675	1,146	2,450	717	4,146	524	69	2,361	1,409	13,497
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	63	2,129	1,293	11,966
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

Figure A1 Ontario's Internal Zones

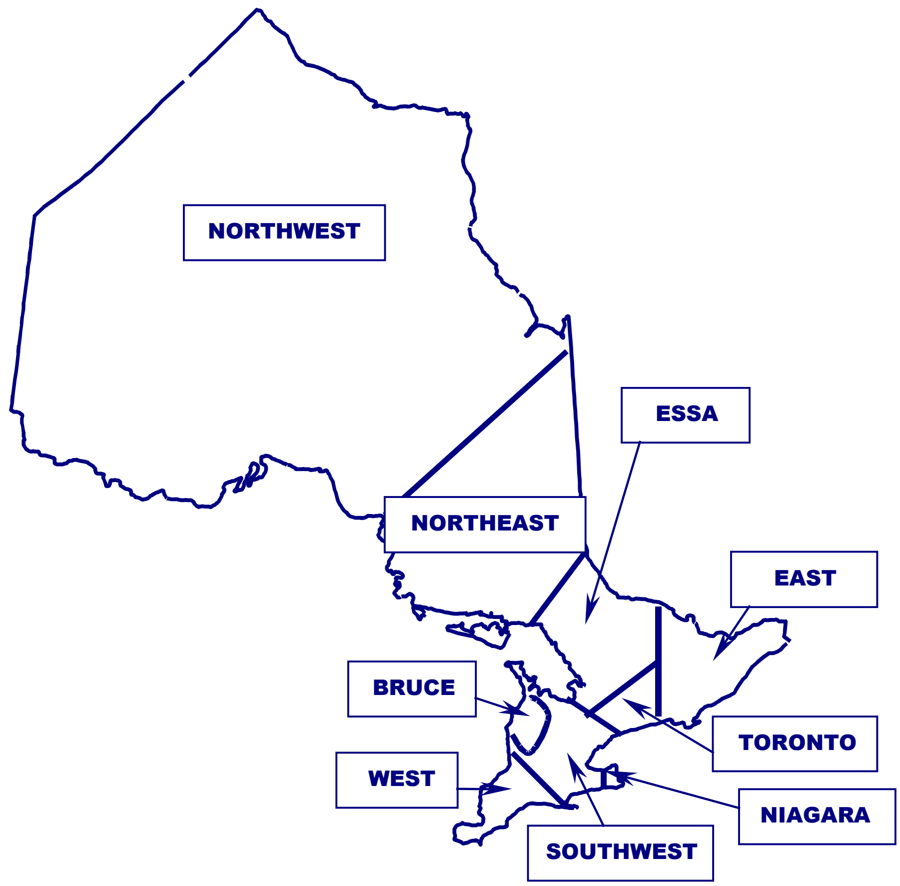

Table A2 Zonal Peak Demand Forecast, Normal Weather

	20-Minute Peak Demand (MW)										
Week Ending	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total System	Load Forecast Uncertainty
08-Apr-01	899	1,369	3,679	914	6,292	781	108	3,610	2,117	19,769	553
15-Apr-01	904	1,366	3,651	907	6,244	771	104	3,527	2,053	19,527	482
22-Apr-01	882	1,311	3,560	885	6,088	781	107	3,570	2,066	19,250	428
29-Apr-01	898	1,275	3,439	855	5,881	767	100	3,331	1,941	18,487	477
06-May-01	869	1,244	3,434	853	5,872	765	96	3,253	1,992	18,378	562
13-May-01	840	1,238	3,356	834	5,739	753	96	3,247	2,111	18,214	597
20-May-01	865	1,238	3,378	839	5,776	766	97	3,267	1,986	18,212	777
27-May-01	822	1,219	3,430	852	5,866	757	99	3,268	2,091	18,404	949
03-Jun-01	832	1,200	3,373	838	5,768	784	99	3,285	2,185	18,364	1,192
10-Jun-01	853	1,206	3,531	854	5,908	776	100	3,365	2,162	18,755	1,169
17-Jun-01	854	1,158	3,937	953	6,588	932	112	3,725	2,761	21,020	1,142
24-Jun-01	861	1,092	4,082	988	6,831	872	110	3,746	2,504	21,086	1,155
01-Jul-01	873	1,108	3,657	885	6,120	898	109	3,649	2,583	19,882	1,156
08-Jul-01	833	1,155	4,320	1,045	7,230	914	117	3,943	2,624	22,181	1,071
15-Jul-01	812	1,116	4,170	1,009	6,978	1,015	118	3,961	3,045	22,224	1,042
22-Jul-01	830	1,113	4,180	1,011	6,995	1,026	120	3,985	3,073	22,333	950
29-Jul-01	808	1,152	4,265	1,032	7,138	912	115	3,883	2,688	21,993	733
05-Aug-01	840	1,142	3,809	922	6,374	960	112	3,743	2,874	20,776	1,067
12-Aug-01	865	1,169	4,074	986	6,818	982	116	3,843	2,951	21,804	1,063
19-Aug-01	866	1,214	4,184	1,012	7,002	934	115	3,860	2,706	21,893	1,081
26-Aug-01	877	1,271	4,155	1,005	6,953	977	118	3,906	2,850	22,112	957
02-Sep-01	888	1,306	3,754	908	6,283	910	109	3,645	2,570	20,373	1,317
09-Sep-01	869	1,319	3,971	961	6,645	882	110	3,696	2,544	20,997	1,244
16-Sep-01	881	1,301	3,810	922	6,376	891	111	3,741	2,569	20,602	933
23-Sep-01	879	1,301	3,664	887	6,132	834	105	3,507	2,410	19,719	948
30-Sep-01	886	1,287	3,475	841	5,815	775	99	3,312	2,167	18,657	819
07-Oct-01	901	1,353	3,557	884	6,082	768	100	3,369	2,009	19,023	610
14-Oct-01	914	1,412	3,673	913	6,281	789	104	3,492	2,045	19,623	351
21-Oct-01	913	1,438	3,701	920	6,329	792	105	3,492	2,021	19,711	386
28-Oct-01	923	1,473	3,730	927	6,379	818	107	3,549	2,085	19,991	466
04-Nov-01	966	1,501	3,869	961	6,616	827	109	3,671	2,178	20,698	391
11-Nov-01	987	1,559	3,832	952	6,553	832	107	3,581	2,190	20,593	456
18-Nov-01	965	1,532	4,094	1,018	7,002	843	114	3,783	2,261	21,612	423
25-Nov-01	968	1,579	4,097	1,018	7,005	830	113	3,784	2,235	21,629	561
02-Dec-01	977	1,638	4,232	1,052	7,237	853	120	4,059	2,352	22,520	464
09-Dec-01	971	1,618	4,177	1,222	7,069	843	119	3,939	2,268	22,226	629
16-Dec-01	978	1,703	4,362	1,276	7,382	857	124	4,133	2,334	23,149	730
23-Dec-01	973	1,626	4,370	1,278	7,396	854	123	4,093	2,368	23,081	697
30-Dec-01	952	1,646	4,179	1,223	7,073	850	115	3,855	2,256	22,149	759

Table A2 – continued

	20-Minute Peak Demand (MW)										
Week Ending	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total System	Load Forecast Uncertainty
06-Jan-02	1,019	1,659	4,257	1,253	7,275	858	118	3,922	2,306	22,667	651
13-Jan-02	1,003	1,694	4,529	1,333	7,739	860	122	4,088	2,363	23,731	737
20-Jan-02	1,017	1,620	4,507	1,326	7,701	862	124	4,172	2,389	23,718	934
27-Jan-02	1,017	1,642	4,288	1,262	7,326	866	122	4,041	2,353	22,917	781
03-Feb-02	1,012	1,622	4,289	1,262	7,329	851	119	3,990	2,285	22,759	671
10-Feb-02	963	1,558	4,391	1,292	7,504	850	125	4,140	2,331	23,154	701
17-Feb-02	970	1,600	4,300	1,266	7,348	841	121	4,043	2,247	22,736	584
24-Feb-02	992	1,592	4,163	1,225	7,114	858	121	4,033	2,313	22,411	749
03-Mar-02	955	1,533	3,941	1,160	6,734	827	113	3,762	2,157	21,182	684
10-Mar-02	971	1,567	4,010	1,180	6,852	838	116	3,877	2,231	21,642	708
17-Mar-02	924	1,467	3,848	1,132	6,575	805	109	3,671	2,113	20,644	728
24-Mar-02	932	1,521	3,813	1,122	6,516	801	110	3,699	2,126	20,640	539
31-Mar-02	891	1,482	3,823	1,125	6,532	796	110	3,656	2,083	20,498	635
07-Apr-02	858	1,507	3,786	958	6,524	803	109	3,647	2,081	20,273	492
14-Apr-02	897	1,410	3,718	941	6,407	783	105	3,552	2,090	19,903	514
21-Apr-02	892	1,357	3,630	918	6,256	799	109	3,618	2,110	19,689	405
28-Apr-02	906	1,265	3,556	900	6,129	789	102	3,405	2,066	19,118	483
05-May-02	900	1,316	3,424	866	5,901	779	99	3,339	2,056	18,680	567
12-May-02	842	1,288	3,412	863	5,880	776	98	3,302	2,149	18,610	590
19-May-02	877	1,283	3,464	876	5,969	776	100	3,340	2,021	18,706	716
26-May-02	828	1,222	3,699	936	6,375	817	103	3,442	2,328	19,750	974
02-Jun-02	827	1,209	3,450	873	5,946	791	98	3,275	2,227	18,696	1,168
09-Jun-02	860	1,266	3,962	964	6,692	814	108	3,582	2,282	20,530	1,135
16-Jun-02	880	1,218	3,928	956	6,636	938	111	3,718	2,767	21,152	1,087
23-Jun-02	885	1,169	4,069	990	6,873	876	111	3,733	2,513	21,219	1,274
30-Jun-02	865	1,194	3,660	891	6,182	873	102	3,417	2,488	19,672	1,223
07-Jul-02	845	1,176	3,977	968	6,717	912	110	3,656	2,593	20,954	1,070
14-Jul-02	833	1,168	4,152	1,011	7,013	1,018	117	3,950	3,046	22,308	988
21-Jul-02	828	1,144	4,217	1,027	7,124	1,034	119	4,015	3,103	22,611	917
28-Jul-02	819	1,168	4,289	1,044	7,245	911	116	3,889	2,711	22,192	908
04-Aug-02	820	1,169	3,854	938	6,510	960	113	3,740	2,901	21,005	996
11-Aug-02	856	1,202	4,105	999	6,935	996	115	3,887	2,977	22,072	1,088
18-Aug-02	876	1,227	4,203	1,023	7,099	932	115	3,864	2,726	22,065	1,089
25-Aug-02	887	1,285	4,174	1,016	7,050	975	116	3,910	2,871	22,284	954
01-Sep-02	898	1,320	3,774	919	6,375	908	108	3,649	2,591	20,542	1,196
08-Sep-02	885	1,401	3,941	959	6,657	884	111	3,692	2,540	21,070	1,256
15-Sep-02	859	1,329	3,854	938	6,510	891	111	3,739	2,592	20,823	839
22-Sep-02	871	1,336	3,700	901	6,250	849	107	3,552	2,436	20,002	1,130
29-Sep-02	878	1,361	3,488	849	5,892	773	100	3,316	2,128	18,785	793

Note to Table A2:

Load Forecast Uncertainty (LFU) represents the degree of deviation in peak due to variations in weather. The LFU is the standard deviation in peak as the result of multiple weather simulations.

Appendix B – Ontario Electricity System – Maps

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Figure B1 Ontario Electricity System

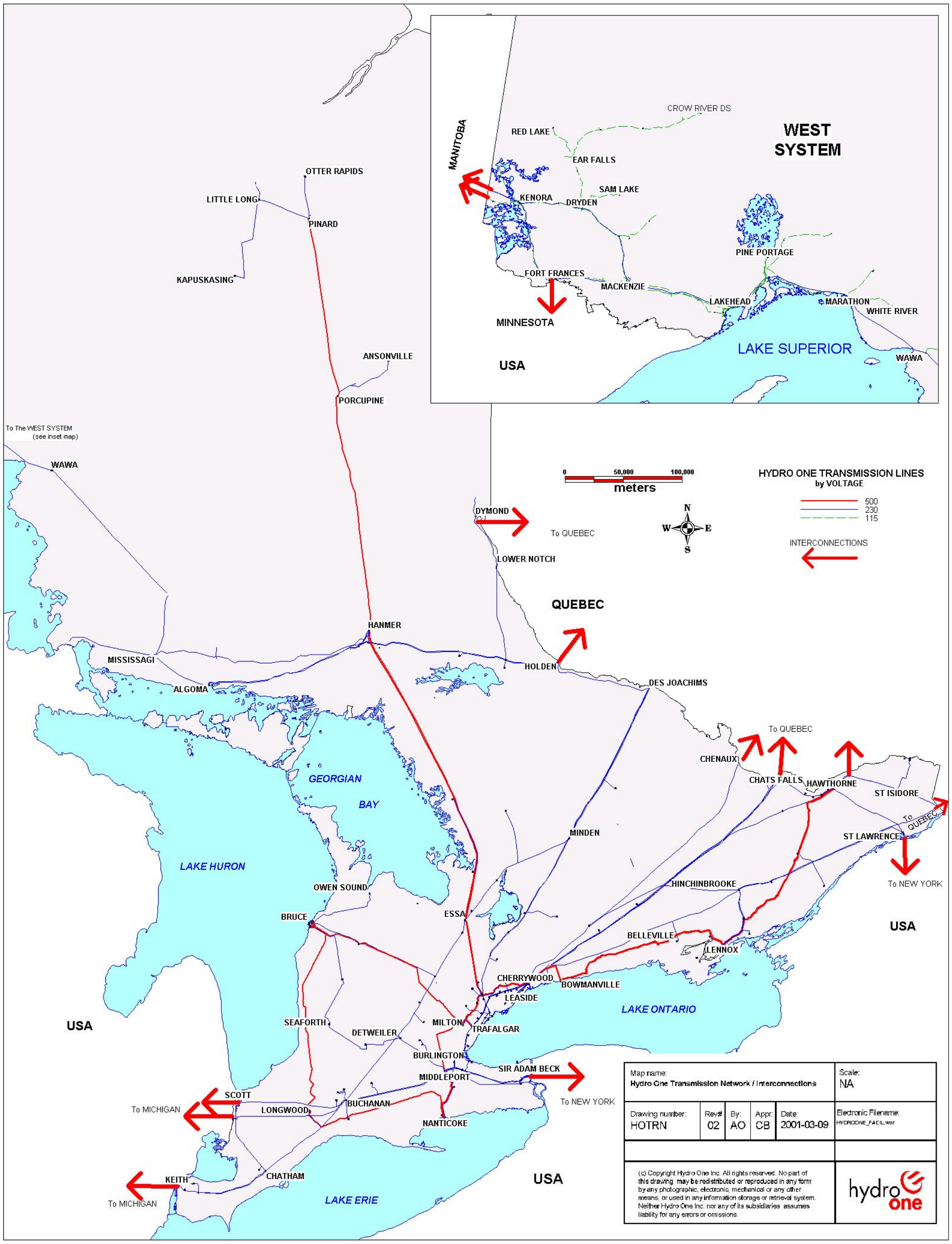


Figure B2 Northern Ontario Electricity System

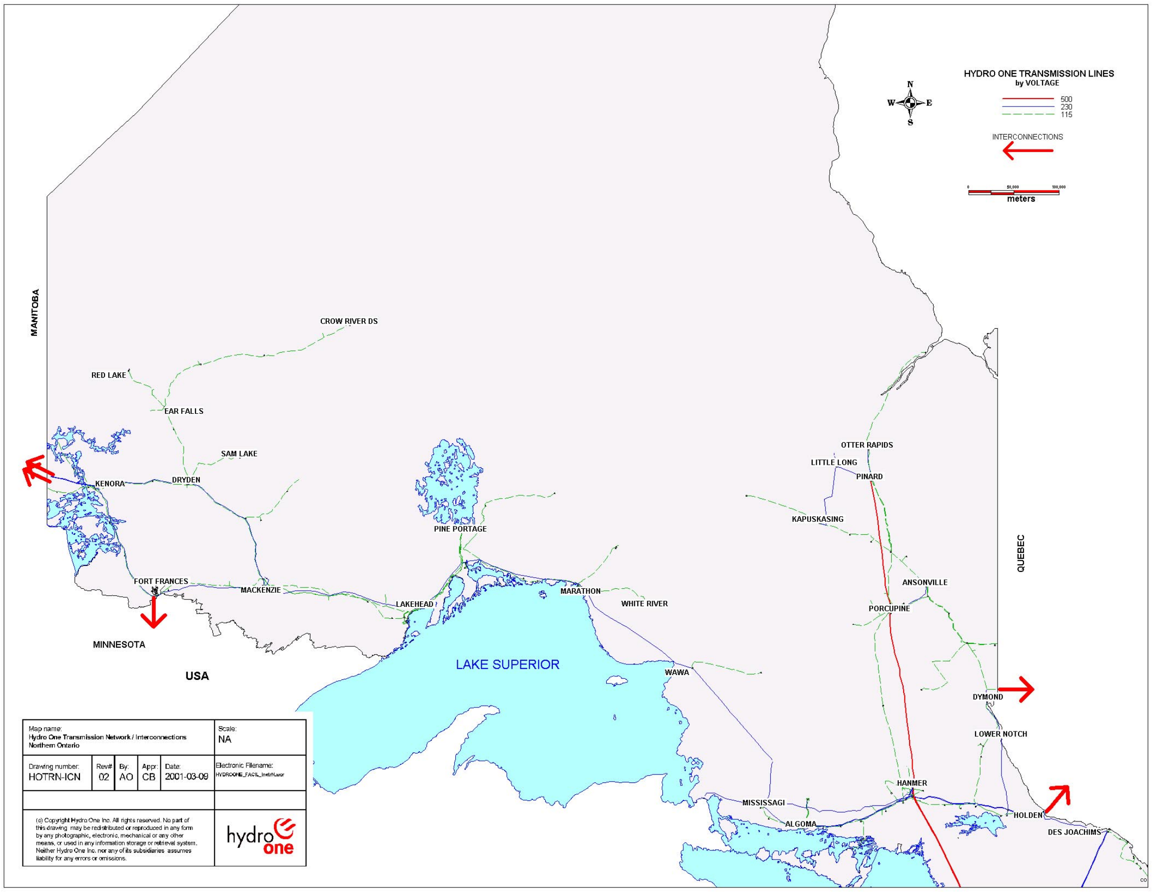
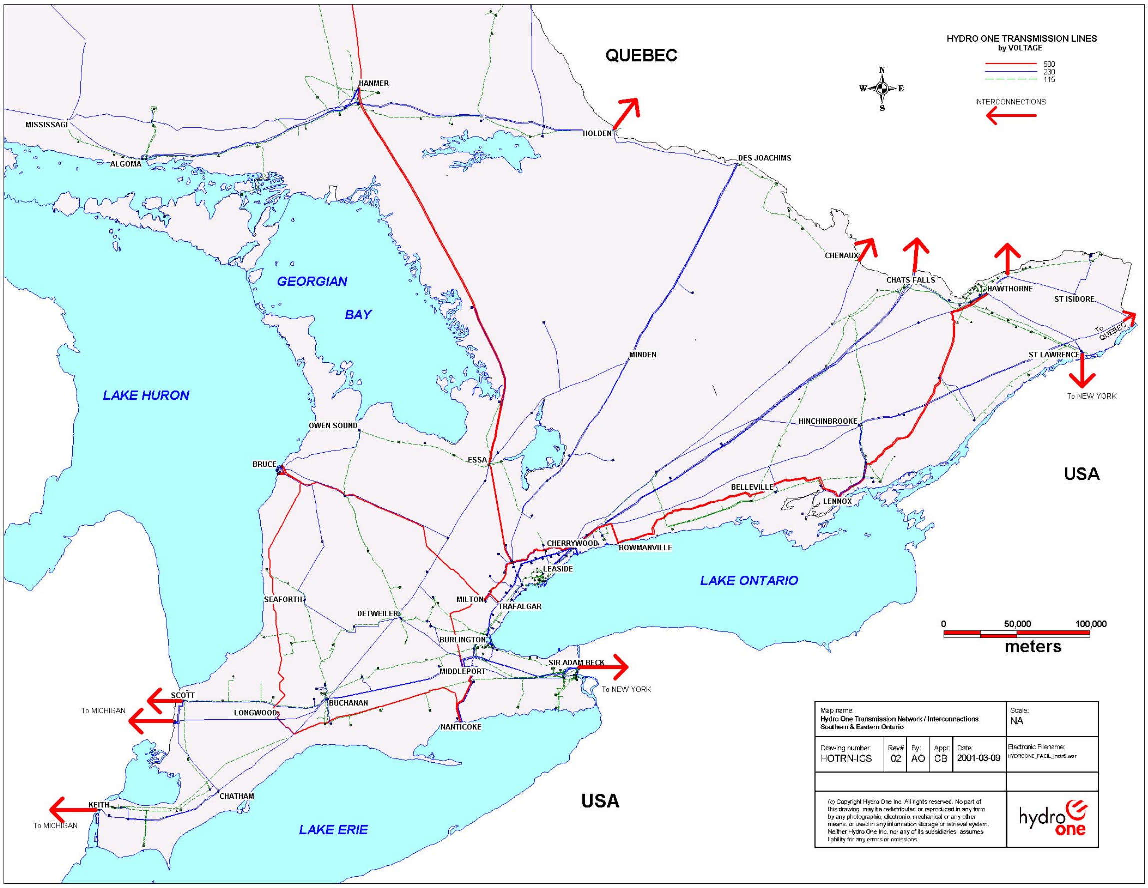


Figure B3 Southern and Eastern Ontario Electricity System



Appendix C – System Resources Details

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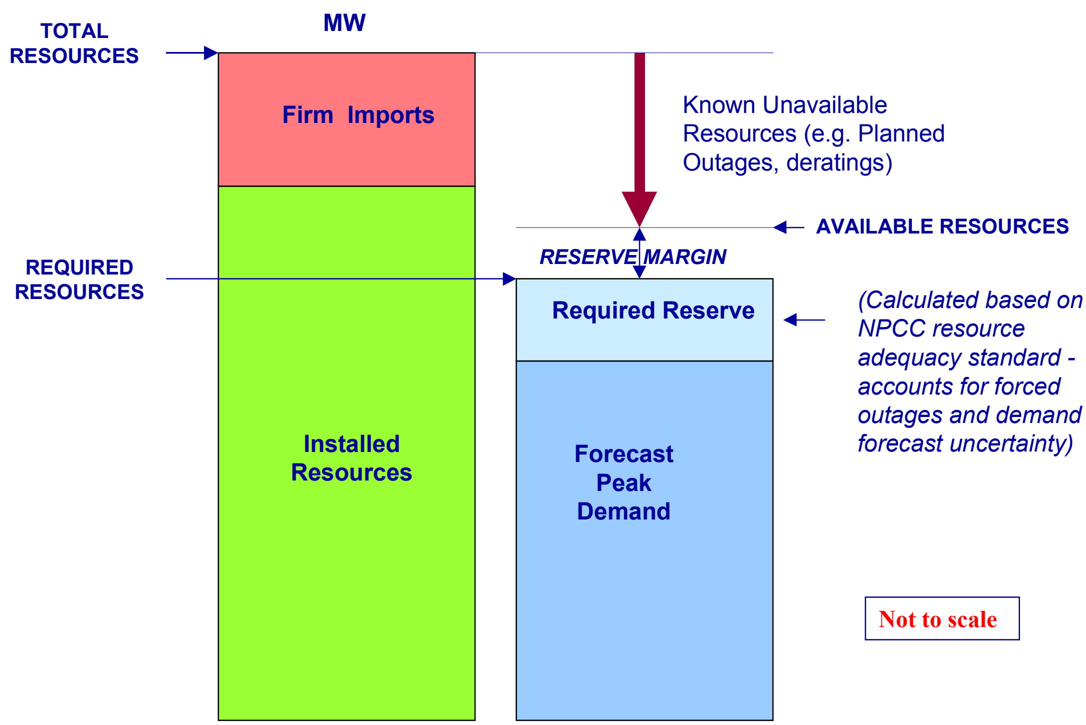
1.0 Required Reserve

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 Load Forecast Uncertainty (LFU) 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 0.1. 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 LFU 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 (Load Forecast Uncertainty or LFU) 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, New York, Michigan, Quebec, Minnesota and Manitoba. For this study, outside generation resources that might bid into Ontario Market 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 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. The total amount of the constrained-off generation varies between 0 and about 350 MW, depending on the load and resource levels, especially in the Northwest zone. Constrained-off generation is subtracted from the Available Resources when calculating the Reserve Margins.

2.0 Resources Adequacy Assessment Table

Table C2.1 Assessment of Resources Adequacy

Week Ending Day	Ontario Demand MW	Total Resources MW	Total Reductions in Resources MW	Available Resources MW	Available Reserve %	Available Reserve MW	Required Reserve %	Required Reserve MW	Reserve Margin MW
08-Apr-01	19,769	30,192	8,376	21,816	12.1	2,347	14.5	2,865	-518
15-Apr-01	19,527	30,192	8,964	21,228	10.4	2,001	14.4	2,814	-813
22-Apr-01	19,250	30,192	6,456	23,736	25.3	4,786	13.8	2,650	2,136
29-Apr-01	18,487	30,192	7,516	22,676	24.7	4,489	13.6	2,512	1,977
06-May-01	18,378	30,192	8,221	21,971	21.5	3,893	13.7	2,513	1,380
13-May-01	18,214	30,192	8,199	21,993	22.8	4,079	13.9	2,525	1,554
20-May-01	18,212	30,192	7,906	22,286	24.4	4,374	14.7	2,685	1,689
27-May-01	18,404	30,192	8,147	22,045	21.8	3,941	15.6	2,869	1,072
03-Jun-01	18,364	30,192	6,377	23,815	31.8	5,751	17.8	3,275	2,476
10-Jun-01	18,755	30,192	6,130	24,062	30.4	5,607	17.5	3,286	2,321
17-Jun-01	21,020	30,192	5,651	24,541	18.4	3,822	16.1	3,391	431
24-Jun-01	21,086	30,192	4,498	25,694	23.6	4,907	16.6	3,497	1,410
01-Jul-01	19,882	30,192	4,285	25,907	32.3	6,325	17.6	3,505	2,820
08-Jul-01	22,181	30,192	4,334	25,858	18.2	3,976	15.7	3,484	492
15-Jul-01	22,224	30,192	4,335	25,857	17.9	3,933	15.6	3,461	472
22-Jul-01	22,333	30,192	4,337	25,855	17.3	3,822	15.2	3,393	429
29-Jul-01	21,993	30,192	4,350	25,842	19.1	4,148	14.2	3,115	1,033
05-Aug-01	20,776	30,192	4,374	25,818	26.1	5,342	16.4	3,409	1,933
12-Aug-01	21,804	30,192	4,396	25,796	20.0	4,292	15.7	3,421	871
19-Aug-01	21,893	30,192	4,571	25,621	18.7	4,028	15.8	3,464	564
26-Aug-01	22,112	30,192	4,627	25,565	17.2	3,753	15.3	3,391	362
02-Sep-01	20,373	30,192	5,051	25,141	25.2	5,068	17.9	3,645	1,423
09-Sep-01	20,997	30,192	5,875	24,317	17.5	3,620	16.9	3,555	65
16-Sep-01	20,602	30,192	6,491	23,701	16.7	3,398	15.6	3,224	174
23-Sep-01	19,719	30,192	7,276	22,916	18.0	3,497	15.6	3,078	419
30-Sep-01	18,657	30,192	7,247	22,945	25.0	4,589	15.3	2,856	1,733
07-Oct-01	19,023	30,192	8,042	22,150	18.3	3,426	13.8	2,618	808
14-Oct-01	19,623	30,192	7,887	22,305	15.4	2,982	13.0	2,548	434
21-Oct-01	19,711	30,192	7,780	22,412	15.5	3,001	13.5	2,652	349
28-Oct-01	19,991	30,192	7,708	22,484	14.2	2,793	13.8	2,751	42
04-Nov-01	20,698	30,192	6,800	23,392	14.7	2,994	13.6	2,805	189
11-Nov-01	20,593	30,192	6,163	24,029	18.4	3,736	13.4	2,754	982
18-Nov-01	21,612	30,192	5,955	24,237	13.7	2,925	13.9	3,002	-77
25-Nov-01	21,629	30,192	5,730	24,462	14.7	3,132	14.1	3,045	87
02-Dec-01	22,520	30,192	4,709	25,483	14.7	3,263	13.7	3,083	180
09-Dec-01	22,226	30,142	4,682	25,460	16.1	3,535	14.0	3,115	420
16-Dec-01	23,149	30,142	4,017	26,125	14.3	3,276	14.4	3,325	-49
23-Dec-01	23,081	30,142	4,010	26,132	14.7	3,351	14.2	3,285	66
30-Dec-01	22,149	30,142	4,015	26,127	19.6	4,278	14.2	3,139	1,139

(Table C1.1 continued)

Week Ending Day	Ontario Demand MW	Total Resources MW	Total Reductions in Resources MW	Available Resources MW	Available Reserve %	Available Reserve MW	Required Reserve %	Required Reserve MW	Reserve Margin MW
06-Jan-02	22,667	30,142	3,970	26,172	17.0	3,805	13.9	3,159	646
13-Jan-02	23,731	30,142	3,598	26,544	13.3	3,113	14.4	3,417	-304
20-Jan-02	23,718	30,142	3,536	26,606	13.6	3,187	15.1	3,579	-392
27-Jan-02	22,917	30,142	4,036	26,106	15.4	3,490	14.4	3,302	188
03-Feb-02	22,759	30,142	4,052	26,090	16.2	3,631	14.0	3,178	453
10-Feb-02	23,154	30,192	4,166	26,026	13.9	3,173	14.2	3,299	-126
17-Feb-02	22,736	30,192	4,639	25,553	13.9	3,117	13.9	3,160	-43
24-Feb-02	22,411	30,192	4,709	25,483	15.3	3,372	14.5	3,249	123
03-Mar-02	21,182	30,192	5,219	24,973	19.6	4,091	13.9	2,943	1,148
10-Mar-02	21,642	30,192	5,212	24,980	17.0	3,639	14.2	3,067	572
17-Mar-02	20,644	30,192	5,751	24,441	20.1	4,097	14.2	2,929	1,168
24-Mar-02	20,640	30,192	5,756	24,436	20.1	4,096	13.5	2,786	1,310
31-Mar-02	20,498	30,192	5,800	24,392	20.8	4,194	13.9	2,843	1,351
07-Apr-02	20,273	30,192	7,177	23,015	15.2	3,042	13.6	2,763	279
14-Apr-02	19,903	30,192	8,637	21,555	10.0	1,951	14.6	2,902	-951
21-Apr-02	19,689	30,192	8,659	21,533	11.1	2,144	14.1	2,775	-631
28-Apr-02	19,118	30,192	8,883	21,309	13.2	2,490	13.9	2,666	-176
05-May-02	18,680	30,192	8,486	21,706	18.1	3,325	13.9	2,602	723
12-May-02	18,610	29,692	7,640	22,052	20.4	3,742	13.7	2,541	1,201
19-May-02	18,706	29,692	7,332	22,360	21.5	3,954	14.3	2,666	1,288
26-May-02	19,750	29,692	6,193	23,499	20.8	4,049	15.5	3,068	981
02-Jun-02	18,696	29,692	6,185	23,507	27.8	5,112	17.7	3,300	1,812
09-Jun-02	20,530	29,692	6,352	23,340	15.4	3,110	16.3	3,345	-235
16-Jun-02	21,152	29,692	5,174	24,518	17.6	3,665	15.9	3,368	297
23-Jun-02	21,219	29,692	5,168	24,524	17.2	3,605	16.9	3,594	11
30-Jun-02	19,672	29,692	4,987	24,705	27.5	5,333	17.8	3,498	1,835
07-Jul-02	20,954	29,692	5,061	24,631	19.3	3,977	15.9	3,337	640
14-Jul-02	22,308	29,692	5,053	24,639	12.0	2,631	15.5	3,459	-828
21-Jul-02	22,611	29,692	4,588	25,104	12.5	2,793	15.1	3,421	-628
28-Jul-02	22,192	29,692	4,588	25,104	14.7	3,213	14.9	3,314	-101
04-Aug-02	21,005	29,692	3,858	25,834	24.8	5,129	16.0	3,361	1,768
11-Aug-02	22,072	29,692	4,339	25,353	16.4	3,580	15.6	3,442	138
18-Aug-02	22,065	29,692	4,495	25,197	15.8	3,432	15.7	3,474	-42
25-Aug-02	22,284	29,692	4,061	25,631	16.6	3,646	15.0	3,351	295
01-Sep-02	20,542	29,692	3,995	25,697	26.9	5,455	17.4	3,575	1,880
08-Sep-02	21,070	29,692	6,302	23,390	12.6	2,620	17.1	3,601	-981
15-Sep-02	20,823	29,692	6,938	22,754	10.9	2,231	15.2	3,175	-944
22-Sep-02	20,002	29,692	7,179	22,513	14.3	2,811	16.6	3,313	-502
29-Sep-02	18,785	29,692	7,124	22,568	22.1	4,083	15.0	2,823	1,260

Appendix D – Transmission System Details

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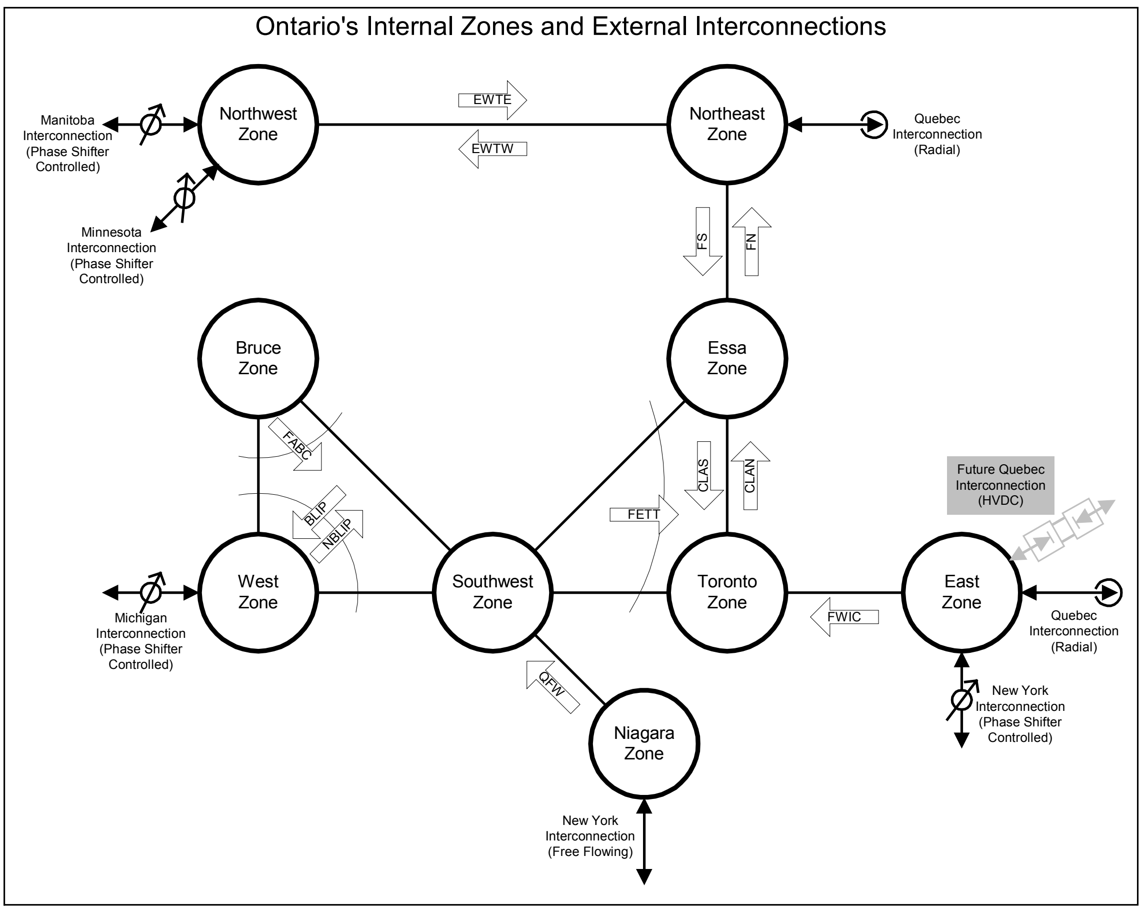
This appendix contains, in Appendix D1, a description of the Ontario Transmission System followed, in Appendix D2 and D3, by Ontario's Interface and Interconnection Definitions and Limits.

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, Ontario 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 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.

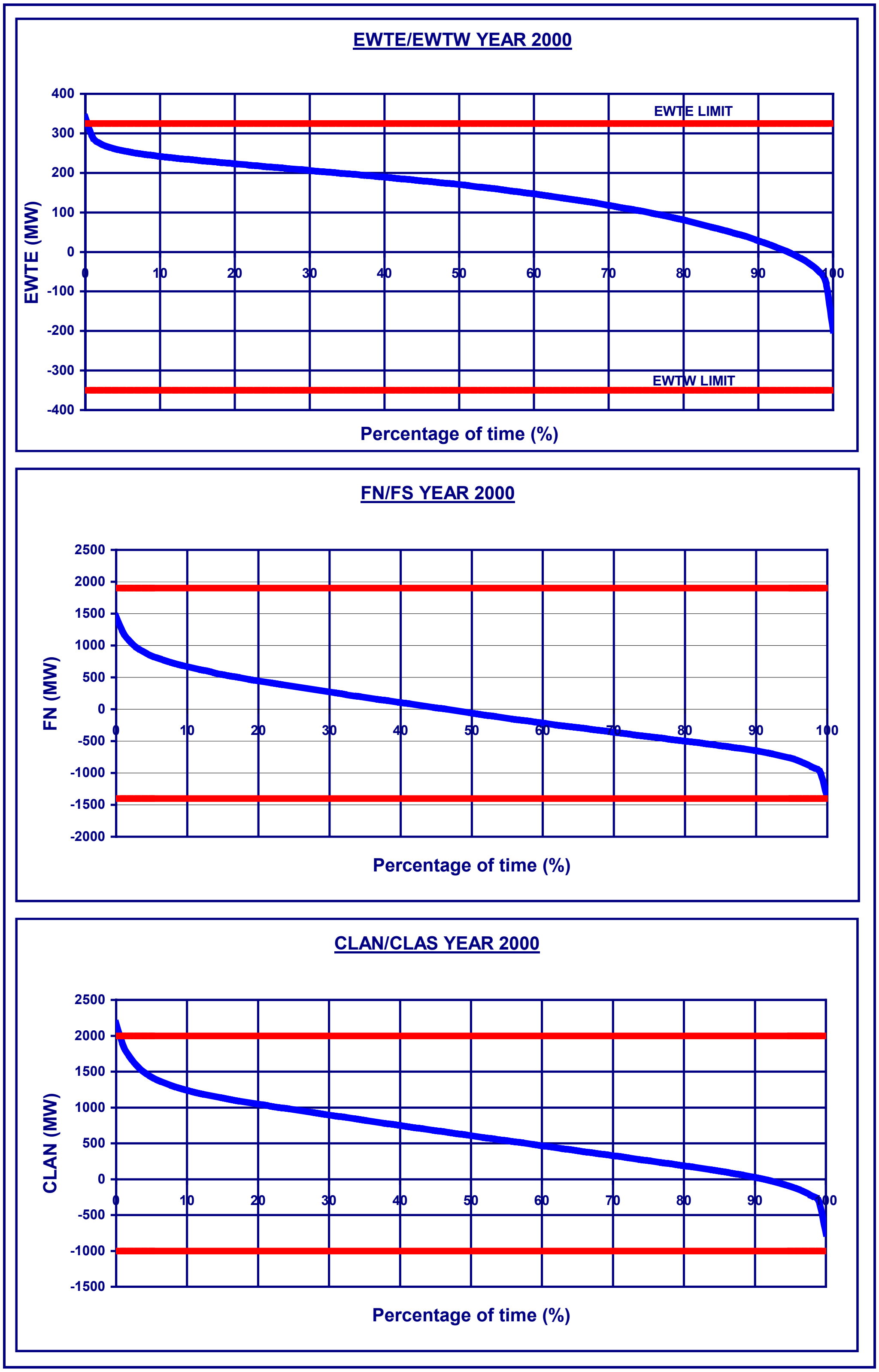
The FN/FS Interface

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 2,000 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.

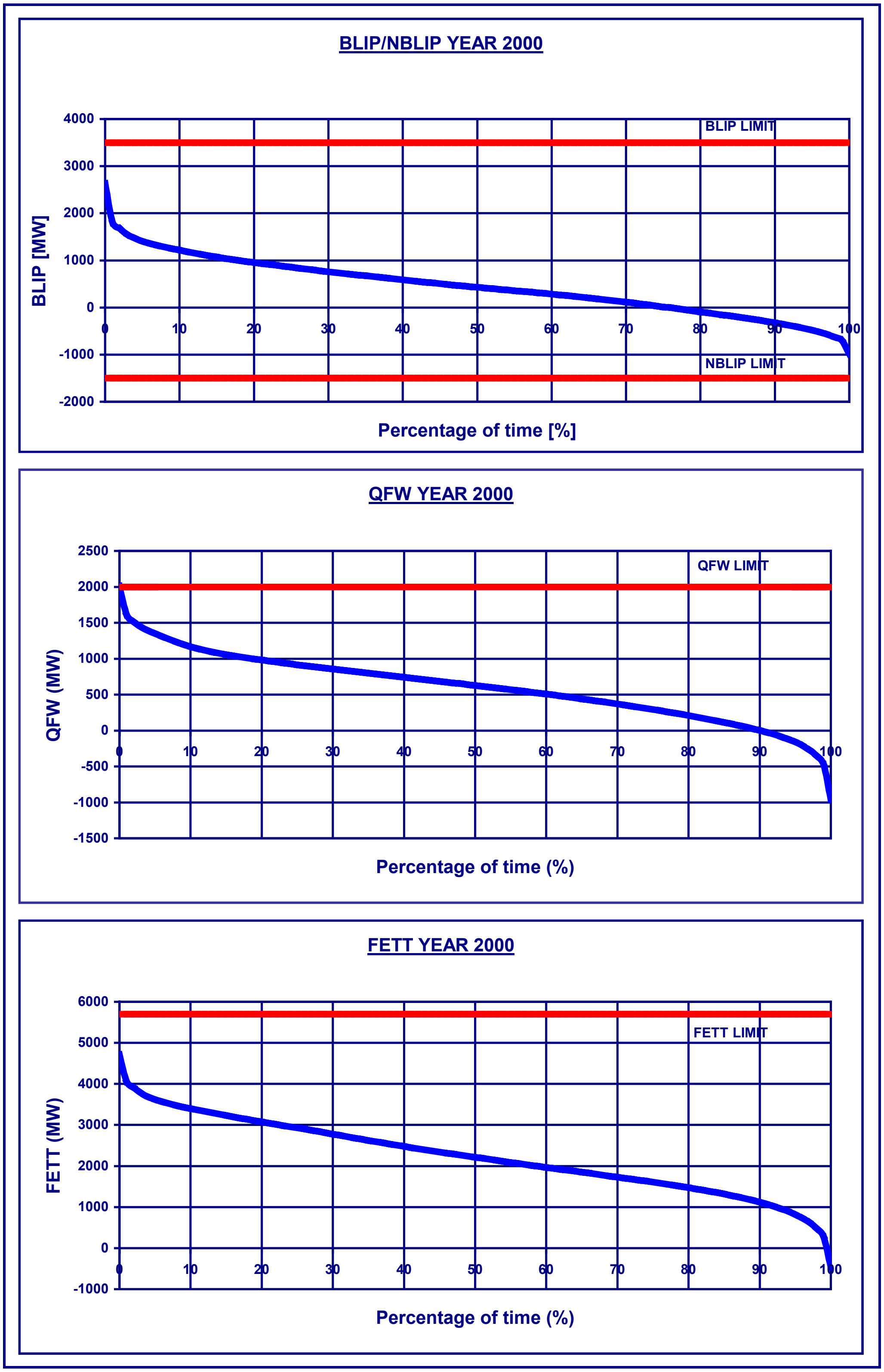
The FETT Interface

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 Ontario 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 circuit 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 Ontario 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 Ontario 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 Ontario 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 Ontario 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 Ontario peak demand.
- The generation is mostly nuclear.
- There are no external interconnections.

Southwest Zone Characteristics

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

West Zone Characteristics

- The total resources are slightly less than the Ontario peak demand.
- The generation is mostly coal.
- The interconnection with Michigan is expected to be under phase shifter control by August 2001.

Niagara Zone Characteristics

- The total resources are much higher than the Ontario 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 under phase-shifter control, except for Niagara - New York. 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 in Manitoba, 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 not expected to be operational before August 2001. 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 around 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.

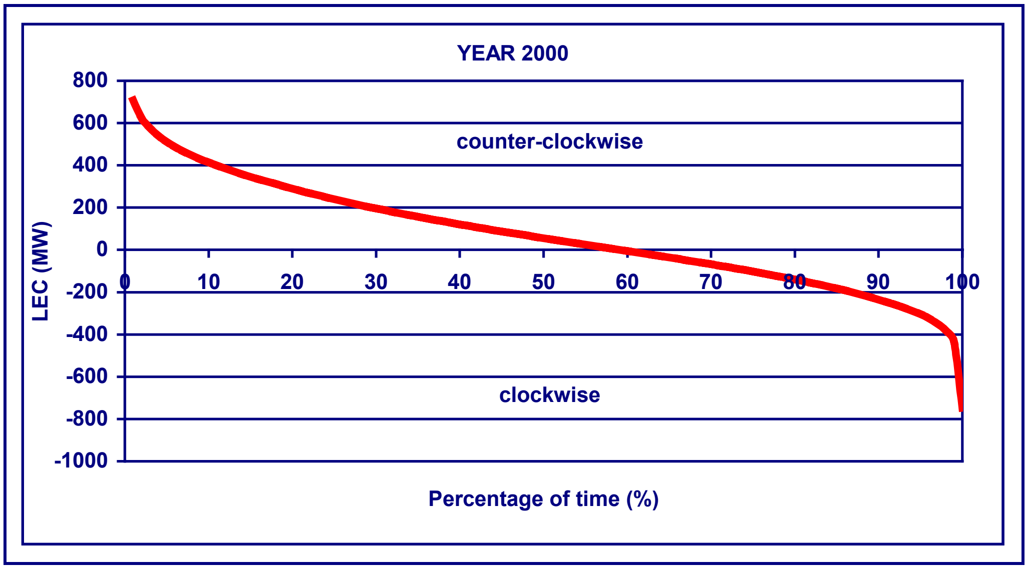
Before phase shifters in service:

During winter months, the limits are 1,600 MW for flows into Ontario and 2,400 MW for flows out of Ontario. In the summer, the limits are 1,500 MW for flows into Ontario and 2,350 MW for flows out of Ontario.

After phase shifters in service:

During winter months, the limits are 1,750 MW for flows into Ontario and 2,700 MW for flows out of Ontario. In the summer, the limits are 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 NY 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 2,000 MW under winter conditions, flow across the NY Niagara interconnection is 1,300 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.

At this time, limits for the HVDC interconnection have not been established.

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 Hamner 500 kV
X504E	Essa* to Hamner 500 kV
D5H	Des Joachims* to Holden 230 kV

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

X503E	Hamner to Essa* 500 kV
X504E	Hamner 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 can be found in the IMO System Control Orders (SCOs). These SCOs are 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, 2000 Winter**
FABC	**5,200, normally not limiting**
FETT	**5,700, 5,500 Summer(1), 5,300Summer(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 Ontario demand is between 22,001 and 22,600 MW.

(2) Limit is used if the summer Ontario 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.

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	Chenaux to Bryson 115 kV,
Q4C	Chats Falls to Quoyon 230 kV,
P33C	Chats Falls to Paugan 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 Moses230 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*	300/190**	369/259**
Manitoba – Summer*	288/163**	343/218**
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)	2,400/2,700***	1,600/1,750***
Michigan – Summer*(2,3)	2,350/2,450***	1,500/1,650***

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

** For the Ontario-Manitoba interconnection, the displayed values are, respectively, before and after January 30, 2002 which is the expected return to service date of Whiteshell T8 transformer.

*** For the Ontario-Michigan interconnection, the displayed values are, respectively, before and after August 2001 which is expected in-service date of the L4D phase shifter.

(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.

4.0 Committed Projects – Hydro One

East Zone - Committed Plans	Projected I/S Date
Cataraqui Transformer Station (TS) - Increase autotransformer capacity; replace secondary buswork.	July 1, 2001
Circuit M32S - Provide 230 kV connection from circuit to Kanata MTS.	October 1, 2001
Circuit B1S - Refurbish 115 kV overhead circuit between Barrette Chute and Ardoch Junction (Jct).	December 1, 2001
St. Lawrence TS - Replace 10 x 230 kV oil breakers with new SF6 breakers.	December 1, 2001
Circuit D5A - replace 62D5A-48 switch with circuit switcher.	December 1, 2001
Belleville TS - Replace 230 kV oil breaker with a new SF6 breaker.	December 31, 2001
Circuits C7BM/W6MC - Reconnect customer stations: Manordale MS, Fallowfield DS, Richmond DS to W6MC from C7BM. Replace 500 m of W6MC 477 kcmil conductor entering Mervale TS with 1192.5 kcmil conductor.	December 1, 2002
Quebec HVDC interconnection - Establish permanent 1250 MW, 230 kV interconnection. Rebuild the Hawthorne x IPBV Masson 115 kV circuit H9A as a double circuit 230 kV line to carry circuits H9A and D5A. Rebuilt the Hawthorne TS x Cumberland Jct. 230 kV circuit D5A as double 230 kV circuit.	December 1, 2002
Nepean TS - Install in-line 230 kV breaker replacing 230 kV switch L22M32S-1.	December 1, 2002

Toronto Zone - Committed Plans	Projected I/S Date
Circuit H2JK - Replace underground cables between Esplanade TS and Don Fleet Jct. Cable will be derated from 1000 A to 680 A due to porous back-fill.	March 1, 2001
Circuits V71R/V75R - Provide 230 kV connection from circuits to Richmond Hill MTS #2.	June 1, 2001
Pickering Nuclear Generating Station (NGS) 'A' switchyard - Replace 8 x 230 kV air break breakers with new SF6 breakers.	December 1, 2001

Northeast Zone - Committed Plans	Projected I/S Date
Kapuskasing area - Reconfigure 115 kV circuit to improve supply reliability. Install 1.8 km circuit and relocate tap to Spruce Falls TS from Spruce Jct. on circuit H9K to circuit F1E at Kapuskasing.	July 1, 2001
Kapuskasing TS - Install 1 x 230 kV breaker at Kapuskasing TS and string 1.8 km of 230 kV circuit between Kapuskasing TS and TCPL Jct.	August 1, 2001
Kapuskasing TS - Remove capacitor bank SC1.	September 1, 2001
Circuit K1Z - Dismantle idle 115 kV, 25 Hz circuit between Kirkland Lake and Provencher.	December 1, 2001
Martindale TS - Replace 230 kV oil breaker with new SF6 breaker.	December 31, 2001
Circuit D2L - Install sectionalizing switches on 115 kV circuit between Dymond and Crystal Falls.	December 1, 2002
Hanmer TS - Install backup circuit breaker for 230 kV SC21 capacitor bank.	December 1, 2002
Wawa TS - Install shunt capacitors at tertiary busses.	December 1, 2002

Northwest Zone - Committed Plans	Projected I/S Date
Lac Des Iles - Increase supply to North American Palladium (NAP) Mine.	December 1, 2001
Fort Frances TS - Replace 2 x 15 MX reactors with 1 x 40 MX reactor.	December 1, 2002
Circuit K6F - Install motorized switch.	December 1, 2002
Thunder Bay Generating Station - Install 115 kV capacitor bank.	December 1, 2002

Southwest Zone - Committed Plans	Projected I/S Date
Circuits R19T/R21T (Hanlan Jct X Pleasant TS) - Provide 230 kV connection from circuits to Brampton Hydro MTS.	July 1, 2001
Elgin TS - Install 2 x 115 kV disconnect switches on transformers T1 & T2.	September 1, 2001
Circuits V74R/V75R - Provide 230 kV connection from circuits to Vaughan MTS #3.	September 1, 2001
Circuit A1T - Dismantle idle 115 kV, 25 Hz circuit between Allanburg and Niagara.	December 1, 2001
Crowland TS - Decommission/remove 25 Hz 115 kV and 27.6 kV facilities.	December 1, 2001
Cambridge TS/Circuits M20D and M21D - Add 230/27.6 kV, 75/125 MVA transformers and connect to 230 kV circuits.	May 1, 2002
Bunting TS, Vansickle TS and Carlton TS - Install 13.8 kV capacitor banks.	June 1, 2002
Beamsville TS - Install 115 kV in-line breaker to circuit D9HS (replaces A1-A2 MSO).	December 1, 2002

West Zone - Committed Plans	Projected I/S Date
Circuits D6V/D7V - Provide connection from circuits to Waterloo North Hydro MTS #3.	May 1, 2001
Chatham TS - Install 230 kV, 225 MVAR capacitor bank and one IPO breaker. Replace the existing 1 mH reactors with 5 mH reactors at SC21. Add 5 mH reactors at SC22. Replace the existing 1.65 mH reactors with 5 mH reactors at SC23.	June 1, 2001
Chatham SS - Replace 14 x 230 kV breakers with new SF6 breakers.	September 30, 2001
Annex TS/Circuits E8F/E9F - Provide 115 kV connection from circuits to station.	December 1, 2001
Circuits Z1E/Z7E - Provide 115 kV connection from circuits to Daimler Chrysler Pillette TS.	December 1, 2001
Circuit K6Z - Reconductor 26 km of 115 kV circuit between Kingsville and Lauzon.	December 1, 2001
Lambton area - Incorporate Enron generator.	December 1, 2001
Scott TS - Replace 5 x 115 kV breakers and reconductor.	December 1, 2001
Windsor area - Provide load rejection /UTLC control schemes.	December 1, 2002

5.0 Planned Transmission Outages

Table D5.1 Transmission Outages Northwest Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Mon 23-Apr-01 07:00	Fri 27-Apr-01 18:00	Kenora TS L21L23	Continuous	NONE		
Mon 23-Apr-01 07:00	Fri 27-Apr-01 18:00	Lakehead TS A BUS, T7 OFF LOAD, SC11 (99 MW)	Continuous	NONE		
Mon 23-Apr-01 07:00	Thu 31-May-01 17:00	K23D Circuit KENORA X DRYDEN	Continuous	NONE	Critical to OMTW, MPFN, EWTE & EWTW. Limits imports from Minnesota and exports to Manitoba. May constrain Northwest generation. Not expected to affect generation reserve requirements.	OMTW: 113 MW; MPFN: 25 MW; EWTE: 75 MW; EWTW: 70 MW
Mon 30-Apr-01 07:00	Fri 04-May-01 18:00	Kenora TS L22L23	Continuous	NONE		
Mon 07-May-01 07:00	Fri 11-May-01 18:00	Mackenzie TS L21L25	Continuous	NONE	Critical to EWTE. May constrain Northwest generation. Not expected to affect generation reserve requirements.	EWTE: 50 MW; however, with K23D & Whiteshell T8 out of sevice, the EWTE limit will be reduced by 75 MW
Mon 14-May-01 07:00	Fri 18-May-01 18:00	Mackenzie TS PL25	Continuous	NONE	Critical to EWTE. May constrain Northwest generation. Not expected to affect generation reserve requirements.	EWTE: 50 MW; however, with K23D & Whiteshell T8 out of sevice, the EWTE limit will be reduced by 75 MW
Tue 21-Aug-01 07:00	Mon 03-Sep-01 23:00	F3M Circuit FT FRANCIS X MP&L, Minnesota Power #10 PHASE SHIFTER (180 MW), #11 PHASE SHIFTER (180 MW)	Continuous	NONE	Critical to MPFN, MPFS, EWTE & EWTW. No Minnesota imports/exports. May constrain Northwest generation. Not expected to affect generation reserve requirements.	MPFN: 100 MW; MPFS: 150 MW; EWTE: 70 MW; EWTW: 70 MW
Tue 04-Sep-01 07:00	Thu 18-Oct-01 18:00	A6P Circuit PATS#1 X RESERVE	Continuous	NONE		
Mon 10-Sep-01 07:00	Fri 14-Sep-01 18:00	Port Arthur #1 A6P BREAKER	Continuous	NONE		
Mon 10-Sep-01 07:00	Fri 02-Nov-01 18:00	M2D Circuit M2D-1 X M2D-D	Continuous	NONE		
Mon 24-Sep-01 07:00	Fri 28-Sep-01 18:00	Dryden TS PL2	Continuous	NONE		
Sat 01-Dec-01 08:00	Sat 15-Dec-01 18:00	Avenor Tbay G4 (18 MW)	Continuous	NONE		

Table D5.2 Transmission Outages Northeast Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Mon 02-Apr-01 06:00	Fri 06-Apr-01 17:00	CKT X27A	Continuous	12 HRS		
Mon 02-Apr-01 08:00	Fri 06-Apr-01 16:00	CKT P22G, Mississagi TS K BUS	Continuous	8HRS		
Mon 09-Apr-01 06:00	Fri 13-Apr-01 16:00	CKT X27A	Continuous	12 HRS		
Mon 16-Apr-01 08:00	Fri 22-Jun-01 16:30	CKT L1S WARREN X CONISTO	Continuous	NONE	Critical to Quebec North transfer. Not expected to be limiting.	5 MW D4Z or H4Z in Mode 2; 15 MW D4Z in Mode 3.
Mon 23-Apr-01 08:00	Fri 11-May-01 16:00	Martindale TS DL6	Continuous	NONE		
Mon 30-Apr-01 07:30	Fri 04-May-01 16:30	CKT D3K DYMOND X DANE	Continuous	12HRS		
Mon 07-May-01 07:30	Fri 11-May-01 16:30	CKT D3K DYMOND X DANE	Continuous	12HRS		
Mon 14-May-01 07:30	Fri 18-May-01 16:30	CKT D3K DYMOND X DANE	Continuous	12HRS		
Mon 21-May-01 07:30	Fri 25-May-01 16:30	CKT D3K DYMOND X DANE	Continuous	12HRS		
Mon 28-May-01 07:30	Fri 01-Jun-01 16:30	CKT D3K DYMOND X DANE	Continuous	12HRS		
Mon 28-May-01 08:00	Fri 15-Jun-01 16:00	Martindale TS EA	Continuous	NONE		
Mon 04-Jun-01 08:00	Fri 08-Jun-01 16:00	CKT S22A, Clarabelle TS T2 TRANSFORMER (125 MW)	Continuous	12 HRS	Critical to EWTE. May constrain Northwest generation. Not expected to affect generation reserve requirements.	50 MW
Mon 04-Jun-01 08:00	Fri 13-Jul-01 16:00	Martindale TS L24L26	Continuous	NONE		
Mon 11-Jun-01 08:00	Fri 15-Jun-01 16:00	CKT S22A, Clarabelle TS T2 TRANSFORMER (125 MW)	Continuous	12 HRS	Critical to EWTE. May constrain Northwest generation. Not expected to affect generation reserve requirements.	50 MW
Mon 18-Jun-01 08:00	Fri 22-Jun-01 16:00	CKT S22A, Clarabelle TS T2 TRANSFORMER (125 MW)	Continuous	12 HRS	Critical to EWTE. May constrain Northwest generation. Not expected to affect generation reserve requirements.	50 MW
Mon 25-Jun-01 08:00	Fri 29-Jun-01 16:00	CKT S22A, Clarabelle TS T2 TRANSFORMER (125 MW)	Continuous	12 HRS	Critical to EWTE. May constrain Northwest generation. Not expected to affect generation reserve requirements.	50 MW
Mon 02-Jul-01 08:00	Fri 06-Jul-01 16:00	CKT S22A, Clarabelle TS T2 TRANSFORMER (125 MW)	Continuous	12 HRS	Critical to EWTE. May constrain Northwest generation. Not expected to affect generation reserve requirements.	50 MW
Mon 09-Jul-01 08:00	Fri 13-Jul-01 16:00	CKT S22A, Clarabelle TS T2 TRANSFORMER (125 MW)	Continuous	12 HRS	Critical to EWTE. May constrain Northwest generation. Not expected to affect generation reserve requirements.	50 MW
Mon 09-Jul-01 08:00	Fri 27-Jul-01 16:00	Martindale TS AL2	Continuous	NONE		
Tue 10-Jul-01 08:00	Fri 07-Dec-01 16:30	CKT L1S WARREN X CONISTO	Continuous	NONE	Critical to Quebec North transfer. Not expected to be limiting.	5 MW D4Z or H4Z in Mode 2; 15 MW D4Z in Mode 3.
Mon 13-Aug-01 07:30	Fri 17-Aug-01 16:30	CKT S2B BALDWIN X MASSEY	Continuous	12 HRS		
Mon 13-Aug-01 08:00	Fri 31-Aug-01 16:00	Martindale TS HL1	Continuous	NONE		
Mon 20-Aug-01 07:30	Fri 24-Aug-01 16:30	CKT S2B BALDWIN X MASSEY	Continuous	12 HRS		
Mon 27-Aug-01 07:30	Fri 31-Aug-01 16:30	CKT S2B BALDWIN X MASSEY	Continuous	12 HRS		
Mon 03-Sep-01 07:30	Fri 07-Sep-01 16:30	CKT S2B BALDWIN X MASSEY	Continuous	12 HRS		
Mon 10-Sep-01 07:30	Fri 14-Sep-01 16:30	CKT S2B BALDWIN X MASSEY	Continuous	12 HRS		
Mon 10-Sep-01 08:00	Fri 28-Sep-01 16:00	Martindale TS EL1	Continuous	NONE		
Mon 17-Sep-01 07:30	Fri 21-Sep-01 16:30	CKT S2B BALDWIN X MASSEY	Continuous	12 HRS		
Mon 24-Sep-01 07:30	Fri 28-Sep-01 16:30	CKT S2B BALDWIN X MASSEY	Continuous	12 HRS		
Sat 13-Oct-01 08:00	Fri 02-Nov-01 16:00	Martindale TS DH	Continuous	NONE		
Mon 22-Oct-01 08:00	Fri 26-Oct-01 16:00	CKT W71D NOTCH X WIDD	Continuous	12 HRS	Critical to Quebec North transfer & Flow North (FN). Not expected to be limiting.	Quebec North Transfer: 120 MW D4Z in Mode 2 or Mode 3 if Lower Notch (LN) is generating; 55 MW D4Z in Mode 2 if LN is condensing; 80 MW D4Z in Mode 2 if LN is o/s; 25 MW D4Z in Mode 3 if LN is condensing; 70 MW D4Z in Mode 3 if LN is o/s. FN: 167MW

Table 5.2 - continued

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Mon 05-Nov-01 08:00	Fri 09-Nov-01 16:00	CKT W71D NOTCH X WIDD	Continuous	12 HRS	Critical to Quebec North transfer & Flow North (FN). Not expected to be limiting.	Quebec North Transfer: 120 MW D4Z in Mode 2 or Mode 3 if Lower Notch (LN) is generating; 55 MW D4Z in Mode 2 if LN is condensing; 80 MW D4Z in Mode 2 if LN is o/s; 25 MW D4Z in Mode 3 if LN is condensing; 70 MW D4Z in Mode 3 if LN is o/s. FN: 167MW
Mon 12-Nov-01 08:00	Fri 16-Nov-01 16:00	CKT W71D NOTCH X WIDD	Continuous	12 HRS	Critical to Quebec North transfer & Flow North (FN). Not expected to be limiting.	Quebec North Transfer: 120 MW D4Z in Mode 2 or Mode 3 if Lower Notch (LN) is generating; 55 MW D4Z in Mode 2 if LN is condensing; 80 MW D4Z in Mode 2 if LN is o/s; 25 MW D4Z in Mode 3 if LN is condensing; 70 MW D4Z in Mode 3 if LN is o/s. FN: 167MW
Mon 19-Nov-01 08:00	Fri 23-Nov-01 16:00	CKT W71D NOTCH X WIDD	Continuous	12 HRS	Critical to Quebec North transfer & Flow North (FN). Not expected to be limiting.	Quebec North Transfer: 120 MW D4Z in Mode 2 or Mode 3 if Lower Notch (LN) is generating; 55 MW D4Z in Mode 2 if LN is condensing; 80 MW D4Z in Mode 2 if LN is o/s; 25 MW D4Z in Mode 3 if LN is condensing; 70 MW D4Z in Mode 3 if LN is o/s. FN: 167MW
Mon 26-Nov-01 08:00	Fri 30-Nov-01 16:00	CKT W71D NOTCH X WIDD	Continuous	12 HRS	Critical to Quebec North transfer & Flow North (FN). Not expected to be limiting.	Quebec North Transfer: 120 MW D4Z in Mode 2 or Mode 3 if Lower Notch (LN) is generating; 55 MW D4Z in Mode 2 if LN is condensing; 80 MW D4Z in Mode 2 if LN is o/s; 25 MW D4Z in Mode 3 if LN is condensing; 70 MW D4Z in Mode 3 if LN is o/s. FN: 167MW

Table D5.3 Transmission Outages Essa Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Mon 09-Apr-01 08:00	Fri 25-May-01 15:30	Essa DL503	Continuous	8 DAYS	Critical to Flow North (FN). Not expected to be limiting. Therefore, not expected to change Northeast dispatch requirements at off peak hours.	450 MW
Mon 16-Apr-01 06:00	Thu 17-May-01 17:00	CKT S2S Meaford x Stayner	Continuous	4 HRS	Critical to Flow Away from Bruce Complex (FABC). Not expected to be limiting.	100-200 MW
Mon 28-May-01 08:00	Fri 06-Jul-01 15:30	Essa DL510	Continuous	8 DAYS	Critical to Flow North (FN). Not expected to be limiting. Therefore, not expected to change Northeast dispatch requirements at off peak hours.	450 MW

Table D5.4 Transmission Outages Bruce Zone

No outages reported.

Table D5.5 Transmission Outages West Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Sun 25-Mar-01 07:00	Fri 06-Apr-01 16:00	Chatham L24L28	Continuous	NONE		
Mon 02-Apr-01 06:30	Mon 02-Apr-01 16:00	CCT C24Z,Lauzon T2,T6,T7,Chatham C24Z TERMINAL	Continuous	4HR		
Tue 03-Apr-01 07:00	Tue 03-Apr-01 16:00	Chatham L28C TERMINAL	Continuous	4HR	Critical to FABC. Not expected to be limiting.	50-100 MW
Sun 22-Apr-01 07:00	Fri 04-May-01 16:00	Chatham KL24	Continuous	N/A		

Table D5.6 Transmission Outages Niagara Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Sun 08-Apr-01 04:00	Thu 12-Apr-01 20:00	SAB#2 K2 BUS	Continuous	6 HOURS	Some of the Beck generation constrained off.	

Table D5.7 Transmission Outages Southwest Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Mon 02-Jul-01 07:00	Fri 06-Jul-01 17:00	CKT M21D	Continuous	None	Critical to FABC. Not expected to be limiting.	100-250 MW
Mon 16-Jul-01 07:10	Fri 20-Jul-01 17:00	CKT M32W	Continuous	8 hours	Critical to FABC. Not expected to be limiting.	100-300 MW

Table D5.8 Transmission Outages Toronto Zone

No outages reported.

Table D5.9 Transmission Outages East Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Tue 17-Apr-01 07:30	Fri 27-Apr-01 15:30	CKT P3S SECT DALE X SID	Continuous	4 HOURS		
Mon 28-May-01 08:00	Fri 01-Jun-01 18:00	CKT X1P	Continuous	8 HOURS		