Independent Electricity Market Operator

10-YEAR OUTLOOK:

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

From January 2005 to December 2014

Executive Summary

Ontario's electricity system faces significant challenges over the next 10 years. The uncertainty surrounding the return to service of Pickering A nuclear units, the lack of new generation investment and the commitment to shut down 7,500 MW of coal fired generation by December 31, 2007, all contribute to a potentially severe shortfall. New transmission, supply and demand side initiatives are urgently needed to address this gap and secure Ontario's energy future.

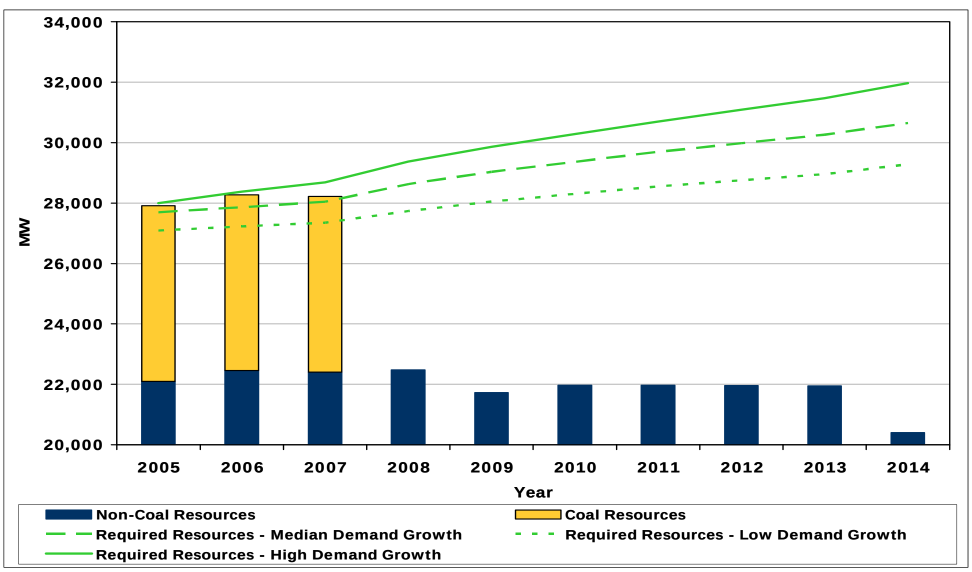
The need is most pressing in the Toronto area, to deal with the immediate impact of the April 30, 2005 shutdown of the Lakeview Thermal Generating Station. Plans are being implemented to address this in the short term. In the longer term, additional generation is also required in the Toronto area to replace the Lakeview generating capacity and to meet load growth in the Greater Toronto Area (GTA).

Each year the Independent Electricity Market Operator (IMO) publishes an integrated assessment of the security and adequacy of the Ontario electricity system over the next 10 years. This report presents the IMO assessment for the 10-year period from 2005 to 2014. It is based on the IMO's forecast of electricity demand, information provided by Ontario generators on the supply that will be available and the latest information on the configuration and capability of the transmission system.

Electricity Supply Outlook

Additional Ontario electricity supply and demand-side measures are required to maintain supply adequacy into the future and to reduce Ontario's dependency on supply from other jurisdictions.

Resource Adequacy Outlook – Annual Peak



The reactivation of 2,000 MW of nuclear capability and the addition of 500 MW of new gas-fired generation over the last 18 months, and the addition of 755 MW of gas-fired generation expected by this summer has eased concerns over the next 18 months. However, more resources are required in every year of the 10-Year Outlook period, some with a high degree of urgency. With the lead times and the quantities of supply and demand resources needed over this period, commitments are required now.

Given the government's commitment to shut down coal-fired generation -- which accounts for some 25 per cent of Ontario's current generating capacity -- a substantial amount of new supply, refurbished generation and demand side resources could be required by 2014. Allowing for typical resource unavailability of 10%, approximately 12,850 MW of supply or demand measures would need to be in place to reliably cover the 2014 peak capacity deficiency of 11,600 MW. The exact amount and timing of the new resources hinges on a variety of factors including demand growth and the performance of Ontario's aging generation infrastructure. The provincial government has indicated that it is developing plans to address this situation.

Proposals for over 30 future generating facilities totaling more than 6,000 MW have been submitted to the IMO. From this total, the capacity available to meet system needs at peak times is estimated to be only 4,000 MW, based on the various capacity factors associated with each generation type. This much capacity, or its equivalent, and more, is needed to meet Ontario's requirements. However, construction of only three of the proposed facilities has started. The provincial government has initiated a Request for Proposals process seeking up to 2,500 MW of new generating capacity and/or demand side initiatives to be developed as early as 2005. The government will also be seeking up to 300 MW of renewable energy capacity to be in service as soon as possible. As in previous Outlooks, the IMO does not include in its assessment those projects for which construction has not begun. Only one of the remaining three Pickering A units is included.

The increasing age of Ontario generation was identified in last year's Outlook as an emerging issue toward the end of the study period and beyond as much of the existing generation infrastructure reaches or exceeds its nominal life.

A significant amount of new generation needs to be situated close to Toronto. To meet power system needs, the Lakeview coal-fired generating station in Mississauga, scheduled to be removed from service on April 30, 2005 in accordance with Ontario Regulation 396/01, should be replaced and augmented by generation or demand initiatives in the GTA, east of Milton, by 2006. All the proposed new generation projects for the Toronto zone address this local requirement, and their timely completion would alleviate supply concerns in downtown Toronto and the western GTA. These projects will complement, but not replace, the need for transmission reinforcements.

With respect to the retirement of coal-fired generation announced by the government, with few exceptions, replacement capacity must be located in the same electrical zone and have the same overall operational characteristics as the station being retired, in order to avoid grid adequacy and operability issues.

Transmission

The need for additional supply and transmission reinforcement to maintain the reliability of the GTA was thoroughly documented in the 2003 10-Year Outlook. The plans to address GTA concerns have evolved substantially over the past 12 months. However it is critically important that sufficient projects are implemented in a timely manner to maintain the required level of reliability.

Several transmission infrastructure additions are required before 2005 summer peak conditions in order to prevent overloading of autotransformers and to provide adequate reactive power to maintain acceptable voltages throughout the western portion of the GTA. Hydro One will be adding a new Transformer Station in Markham, extending an existing 230 kV double circuit line between Richmond Hill and Markham, and installing new equipment in a number of stations within the GTA.

The IMO has directed Ontario Power Generation to retain the option to convert two Lakeview generating units to synchronous condensers should the reactive power needed to support voltages in the GTA not be available from other sources. No coal burn is required for this mode of operation.

For implementation further along in the decade, Hydro One has proposed two alternative transmission projects to address the need for a third supply to downtown Toronto – a Direct Current (DC) Option and an Alternating Current (AC) Option. Both options meet IMO criteria and improve the reliability of supply to downtown Toronto. However the DC option is preferred as it requires fewer system upgrades.

Additional transmission facilities have also been proposed for the areas west and north of Toronto to increase the supply capability to southern Mississauga, southern Oakville, Markham, Richmond Hill, Vaughan, Newmarket and Aurora. However, the supply delivery capability to the rest of Mississauga, and to Brampton, Milton and northern Oakville remains a concern. Due to the high rate of load growth in these areas, there is a need to increase transmission capability.

New transmission reinforcements are also required for other parts of Ontario including Kitchener-Waterloo, Cambridge, Guelph and Windsor as discussed in the recent Hydro One report “Transmission Solutions – A 10-Year Transmission Plan for the Province of Ontario 2004-2013”.

Ontario Demand Forecast

Without significant conservation efforts, energy consumption is forecast to grow from about 156 terawatt-hours (TWh) in 2005 to about 169 TWh in 2014, an average annual growth rate of energy of 0.9%.

Normal weather peak demands are expected to increase from about 24,160 MW in 2005 to 26,610 MW in the summer of 2014, an increase of 2,450 MW. Under extreme weather conditions, the summer peak is projected to approach the 30,000 MW level by the end of the forecast period.

- End of Section -

This page intentionally left blank.

Caution and Disclaimer

This page intentionally left blank.

Table of Contents

List of Tables

List of Figures

1.0 Introduction

This report presents a 10-year forecast and assessment of the adequacy of generation and transmission facilities in Ontario. Its primary purpose is to provide information to market participants for long-term planning and investment decisions.

This report incorporates information received from market participants between December 2003 and February 2004. It supercedes the previous 10-Year Outlook published by the Independent Electricity Market Operator (IMO) on March 31, 2003.

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

The contents of this Outlook document focus on the assessment of resource and transmission adequacy to reliably supply load. Other supporting information, forecasts and assessments are contained in separate documents. These documents will be updated as required.

- The document titled "Ontario Demand Forecast from January 2005 to December 2014" (IMO_REP_0173) (found on the IMO Web site at www.theimo.com/imoweb/pubs/marketReport/10Year_ODF_2004mar.pdf) describes in detail the forecast of electricity demand for Ontario used in this Outlook. The document provides the details regarding peak and energy demand forecasts for Ontario and parts thereof. It also contains information regarding variations in demand due to weather, economic growth and calendar day types.
- The document titled "Methodology to Perform Long Term Assessments" (IMO_REP_0044) (found on the IMO Web site at www.theimo.com/imoweb/pubs/marketReports/Methodology_RTAA_2004mar.pdf) contains information regarding the methodology used to perform the demand forecasts, and resource and transmission adequacy assessments in this Outlook.
- The document titled "Ontario Transmission System" (IMO_REP_0045) (found on the IMO web site at www.theimo.com/imoweb/pubs/marketReports/OntTxSystem_2004mar.pdf) provides specific details on the transmission system, including the major internal transmission interfaces and interconnections with neighbouring jurisdictions.

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.

1.1 Changes from the Previous 10-Year Outlook

Changes to Forecast Demands

Compared to the previous 10-year forecast the most significant impacts have been the actual events of 2003. Both from an economic and an electricity demand perspective, 2003 was an unusual year. The year started out strong with year-over-year employment growth averaging in excess of 3.5%. As well, the monthly peaks for January through April each represented high-water marks for their respective months. Weather-corrected demand also averaged year-over-year growth of over 3.0% for the first four months of 2003. However, by the end of May year-over-year weather-corrected demand growth was down to 0.3% and the Canadian dollar had appreciated by 13% against the U.S. dollar since the start of the year. By July, year-over-year employment growth had dropped one percentage to 2.8% and weather-corrected energy demand was showing a year-over-year decline of 4.8%. In August both the economy and electricity demand were impacted by the blackout and ensuing calls for conservation. That time period also coincided with the hottest weather of the summer, so most of the weather-sensitive demand was "lost". The year ended with employment growth at 1.8% and weather-corrected energy demand at 0.2% growth. The events of 2003 have therefore had a significant impact on this 10-year demand forecast. Not only do the actuals impact the models as they are re-estimated, but some of the developments of 2003, the lower U.S. dollar and jobless U.S. recovery, will impact the underlying fundamentals going forward.

The events of 2003 have therefore influenced the new 10-Year forecast. Both energy and peak demand are lower than the previous forecast. Whereas last years' forecast was predicated on an annual energy demand of 152.6 terawatt-hours (TWh), this forecast has a weather corrected starting point of 151.7 TWh for 2003. The lower starting point will contribute to some of the difference in the energy demand forecasts. The projected average annual energy demand growth rate is 0.9% (2005-2014) for the current forecast as compared to the 1.0% (2004-2013) for the previous forecast. The lower demand is a function of lower economic growth due to the higher Canadian dollar and a weaker U.S. economy.

The demand forecast does include a high growth scenario, which has average annual energy demand growth of 1.3% and a low growth scenario with 0.6% average annual growth. The scenarios are generated using stronger than anticipated, and lower than anticipated economic growth. In 2013, annual energy demand is forecasted to be 167.8 TWh, down from the 168.7 TWh in the previous forecast. The results are similar for the high growth (176.0 TWh versus 177.3 TWh) but reversed for the low growth scenario (159.0 versus 158.3 TWh).

Lower economic growth and higher rates of conservation and price responsive demand mean that forecasted peak demands are lower than in the previous forecast. The summer peak is expected to grow at 1.1% (versus 1.3% previously) and the winter peak will grow at an annual average rate of 0.7% (versus 0.8% previously). The peaks themselves are predicted to be 25,500 MW for the winter of 2013 (versus 25,600 MW previously) and the summer 2013 peak is forecasted to be 26,400 MW (versus 26,800 MW).

The continued growth of cooling load means that the system will be summer peaking in 2006 under Normal weather, and is currently summer peaking under the Extreme weather scenario.

Changes to Resources

The amount of existing installed generation resources has been updated from the previous 10-Year Outlook to include all generators that are registered to participate in the IMO-administered markets. The latest generation resource additions and upgrades, and the latest capacity ratings are also included. The list does not include generators that are not registered to participate in the IMO-administered markets.

With the uncertainty around the further reactivation of Pickering A nuclear units, the IMO has decided to include only the one operable unit, Unit 4, in the list of existing installed generation resources. Of the three remaining units, only Unit 1 is assumed to come back in service, during Q4 2005. Three Pickering B units are expected to reach end-of-tube life within the study timeframe. For analysis purposes they are assumed to come out of service at the end of 2013.

The amount of planned outages assumed to take place over the seasonal peak demand periods has been changed to approximately 900 MW over the winter peak period and approximately 500 MW over the summer peak period, from 900 MW considered in the previous 10-Year Outlook. This assumption is consistent with the maintenance scheduling behaviour observed over the last few years.

Changes to Transmission Outlook

The different transmission network scenarios used in the transmission adequacy assessment have been updated to incorporate new or updated transmission projects received over the past 12 months for Connection Assessment and Approval (CAA).

The resources and demand scenarios used in the transmission adequacy assessment have also been updated.

- End of Section -

This page intentionally left blank.

2.0 Resources

This section describes the generation resources that are forecast to be in service throughout the ten-year study period, taking into account existing generation and generation resource additions and retirements, based on information available to the IMO.

2.1 Existing Generation Resources Included in the Study

The existing installed generation included in the study is summarized in Table 2.1. It includes nuclear, coal, oil, gas, hydroelectric, wood and waste-fuelled generation, which adds to a total installed capacity of 30,501 MW.

The capacity of installed generation resources in Table 2.1 includes Bruce A Units 3 and 4.

With the increasing uncertainty around the further reactivation of the remaining Pickering A nuclear units, the IMO has decided to include only the one operable unit, Unit 4, in the list of existing installed generation resources.

Table 2.1 Existing Installed Generation Resources

Resource Type	Total, MW	Percentage of Total, %	# of Stations
Nuclear	10,831	35.5	5
Coal	7,564	24.8	5
Oil/Gas	4,364	14.3	22
Hydroelectric	7,676	25.2	61
Miscellaneous	66	0.2	2
Total	30,501	100.0	95

2.2 Potential New Generation Resources

Table 2.2 summarizes the new generation projects in the CAA process. Generator owners or operators have provided the information regarding the status of their projects and the in-service dates listed in Table 2.2. Although over 6,000 MW of generation additions remain in the IMO queue, the continued deferral of many of these projects, year over year, has prompted the IMO to develop resource scenarios which only consider those generation additions that are under construction.

Details regarding the IMO's CAA process and the status of all projects in the queue, including copies of available Preliminary Assessment and System Impact Assessment Reports, can be found on the IMO's web site www.theIMO.com under the "Services - Connection Assessments" link.

Table 2.2 Potential Generation Resource Additions in Ontario

Proponent/Project Name	Zone	Fuel Type	Capacity MW	Connection Applicant's Estimated I/S Date	Under Construction*
ATCO Power Ltd. - Windsor	West	Gas	625	2004 - Q2	Yes
Imperial Oil Ltd. - Sarnia	West	Gas	98	2004 - Q2	Yes
Northern Cross Energy - Goderich	Southwest	Gas	50	2004 - Q2	No
Northland Power Inc. - Kirkland Lake	Northeast	Gas	32	2004 - Q3	Yes
Toronto Hydro ES Inc. - Portlands	Toronto	Gas	180	2004 - Q3	No
Hydro One for Vision Quest - Kincardine	Bruce	Wind	15	2004 - Q4	No
Hydro One for Vision Quest - Picton	East	Wind	22	2004 - Q4	No
OPG - Beck GS#2 - Generation Rehabilitation	Niagara	Hydro	192	2004 - Q4	No
Superior Wind Energy Inc. - Manitoulin Island	Northeast	Wind	100	2005 - Q1	No
AIM POWERGEN - Lake Erie Northshore	West	Wind	150	2005 - Q2	No
Superior Wind Energy Inc. - Sault St. Marie	Northeast	Wind	100	2005 - Q2	No
Chinodin Entreprises - Grey Highland Wind Project	Southwest	Wind	240	2005 - Q3	No
Enersource Hydro Mississauga - Pearson Int. Airport	Toronto	Gas	117	2005 - Q3	No
GAIA Power Inc. - Wolfe Island	East	Wind	35	2005 - Q3	No
Superior Wind Energy Inc. - Bruce Peninsula	Southwest	Wind	100	2005 - Q3	No
Superior Wind Energy Inc. - Leamington	West	Wind	200	2005 - Q3	No
AGSTAR Power Inc. - Tilbury	West	Gas	88	2005 - Q4	No
Port Albert Wind Farms - Goderich	Southwest	Wind	57	2005 - Q4	No
Repower Wind Corp. - Manitoulin Island	Northeast	Wind	57	2005 - Q4	No
Boralex Inc. - Mississauga	Toronto	Gas	125	2005 - Q4***	No
Superior Wind Energy Inc. - Collingwood	Southwest	Wind	200	2006 - Q1	No
Northland Power Inc. - Thorold	Niagara	Gas	273	2006 - Q3	No
Ontario Power Generation Inc. - Portlands Energy Centre (formerly "Hearn")	Toronto	Gas	550	2006 - Q3	No
Superior Wind Energy Inc. - Bruce Peninsula	Southwest	Wind	100	2006 - Q3	No
Superior Wind Energy Inc. - Marathon	Northwest	Wind	200	2006 - Q3	No
Port Albert Wind Farms - PAWF Phase IV	Southwest	Wind	300	2006 - Q4	No
Sithe Canadian Holdings Inc. - Goreway Brampton	Toronto	Gas	932	2006 - Q4	No
Sithe Canadian Holdings Inc. - Goreway Brampton**	Toronto	Gas	1009	2006 - Q4	No
Superior Wind Energy Inc. - Sault St. Marie	Northeast	Wind	100	2006 - Q4	No
OPG - Lac Seul GS	Northwest	Hydro	13.6	2007 - Q1	No
Sithe Canadian Holdings Inc. - Southdown Mississauga	Toronto	Gas	763	2007 - Q1	No
Sithe Canadian Holdings Inc. - Southdown Mississauga**	Toronto	Gas	336	2007 - Q1	No
Canadian Renewable Energy Corporation - Wolfe Island	East	Wind	360	2010 - Q3****	No
Total			6,025 - 6,375		

* For projects which are not under construction, the IMO assumes no commitment on the part of the market participant to complete the project.

** Alternatives to the initially proposed Southdown and Goreway projects of Sithe Canadian Holdings Inc.

*** The capacity of the Boralex project is planned to be made available in stages, between Q4 - 2004 and Q4 - 2005.

**** The capacity of the Wolfe Island project is planned to be made available in stages, between Q3 - 2005 and Q3 - 2010.

2.3 Summary of Generation Resource Scenarios

In assessing future resource adequacy, it is necessary to make a number of assumptions regarding the magnitude of supply resources that will be available for operation. The completion of a number of projects and the growing possibility that others may be abandoned, narrows the set of resource scenarios the IMO considers valuable to study. For that reason, only one primary resource scenario was developed for this Outlook with respect to the level of in-service resources; it is called the Reference Resource Scenario.

The **Reference Resource Scenario** assumes that:

- existing Ontario resources, listed in Table 2.1, will be in-service for the entire duration of the study period, with the following exceptions:
  - Lakeview units will be removed from service by May 1, 2005;
  - Coal-fired generation at Nanticoke, Lambton, Atikokan and Thunder Bay will be removed from service by the end of 2007;
  - Bruce A Unit 3 will be removed from service beginning January 1, 2009. This is a conservative assumption that will be reviewed as part of the market participant's normal business planning process. Further operation beyond this date will depend on the material condition of the unit and market conditions; and
  - Pickering B Units 5, 6 and 7 pressure tubes reach the end of their life by 2013; for analysis purposes, the three units were assumed to be out of service starting January 1, 2014, pending development of refurbishment plans by Ontario Power Generation, (OPG).
- the additional generation resources listed in Table 2.2, for which the connection applicant has indicated that construction is in progress or has been completed will be in service. In developing the scenario, these resource additions were assumed to be complete on the dates provided by market participants;
- of the remaining three Pickering A units, only Unit 1 was assumed to return to service prior to the 2006 system peak. The return to service is planned for Q4 2005 based on information provided by OPG; and
- 300 MW of price-responsive demand will be active in the market.

Table 2.3 shows the installed generation resources, at the time of the annual peak demand, under the Reference Resource Scenario. The values in the table do not include the 300 MW of price-responsive demand.

Table 2.3 Installed Generation Resources at Annual Peak

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Installed Resources	30,258	30,823	30,823	24,407	23,637	23,873	23,873	23,873	23,873	22,325

- End of Section -

This page intentionally left blank.

3.0 Resource Adequacy Assessment

This section provides an assessment of the adequacy of the resources described in Section 2 to meet the forecast demand. Capacity analyses were performed using the Load and Capacity program (L&C), and the Multi-Area Reliability Simulation program (MARS). The methodology and tools used to carry out these analyses are described in detail in the document titled "Methodology to Perform Long Term Assessments" (IMO_REP_0044). The resource availability scenario is described in Section 3.1, results of the L&C and MARS runs are described in Section 3.2, the need for additional resources and the various related aspects are discussed in Section 3.3, and other considerations and influencing factors are briefly discussed in Section 3.4. Conclusions are provided in Section 5, and detailed result tables can be found in Appendix A.

3.1 Supply/Demand Modeling Approach

The resource availability scenario used in the capacity analyses was created using the generation resources described in Section 2.3. Generator deratings, planned and long-term generator outages, generation constrained off due to transmission interface limitations and allowances for non-utility and hydroelectric generation production below rated capacity were combined with installed generation resources.

For the first year of the study period, specific generator outage plans have been used. For the last nine years of the study period explicit generator outage plans were unavailable. For these years it was necessary to model a hypothetical outage plan to reflect known cyclic outages (such as nuclear station containment outages) and planned outage factors supplied by generator participants. This is referred to as a "generic" outage plan to reflect the fact the majority of assumptions were modeled repetitively for nine of the ten years studied.

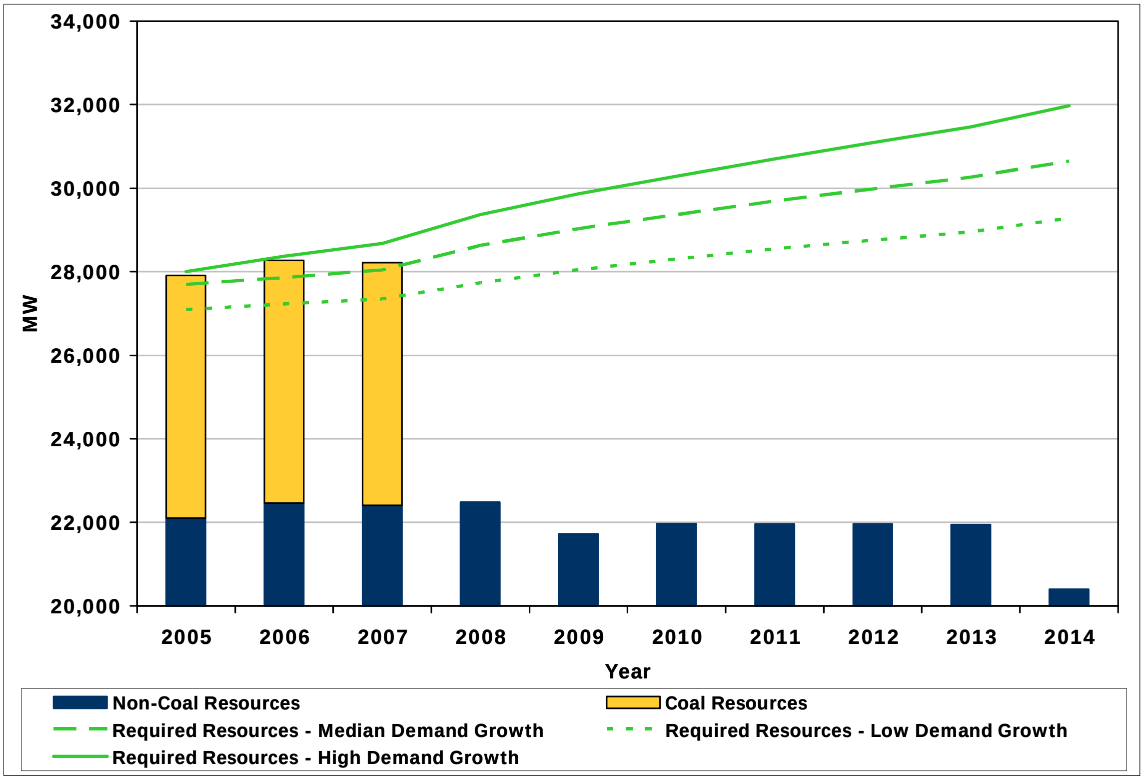
The forecast demand scenarios used to perform the adequacy assessment correspond to low, median and high demand growth. Comprehensive analyses were carried out for all combinations of demand growth scenarios and the Reference Resource Scenario.

3.2 L&C and MARS Results

L&C model calculations were performed for the Reference Resource Scenario described in Section 2.3, with reserves calculated for the weekly peaks of each year in the study period, for each demand scenario. Graphical results of the L&C program calculations, for the annual peaks, are shown in Figure 3.1. Tables A1 to A6 in Appendix A provide more numerical details.

The MARS program calculations were performed in two steps. In the first step, the same resources as in the L&C calculations were modeled in MARS. In the second step, additional supply was modeled in any scenario for which the annual Loss of Load Expectation (LOLE) was computed to be greater than 0.1 days/year. The second step was repeated, with increasing amounts of additional supply, until all annual LOLE values became less or equal to the Northeast Power Coordinating Council standard of 0.1 days/year.

Figure 3.1 Resource Adequacy Outlook – Annual Peak



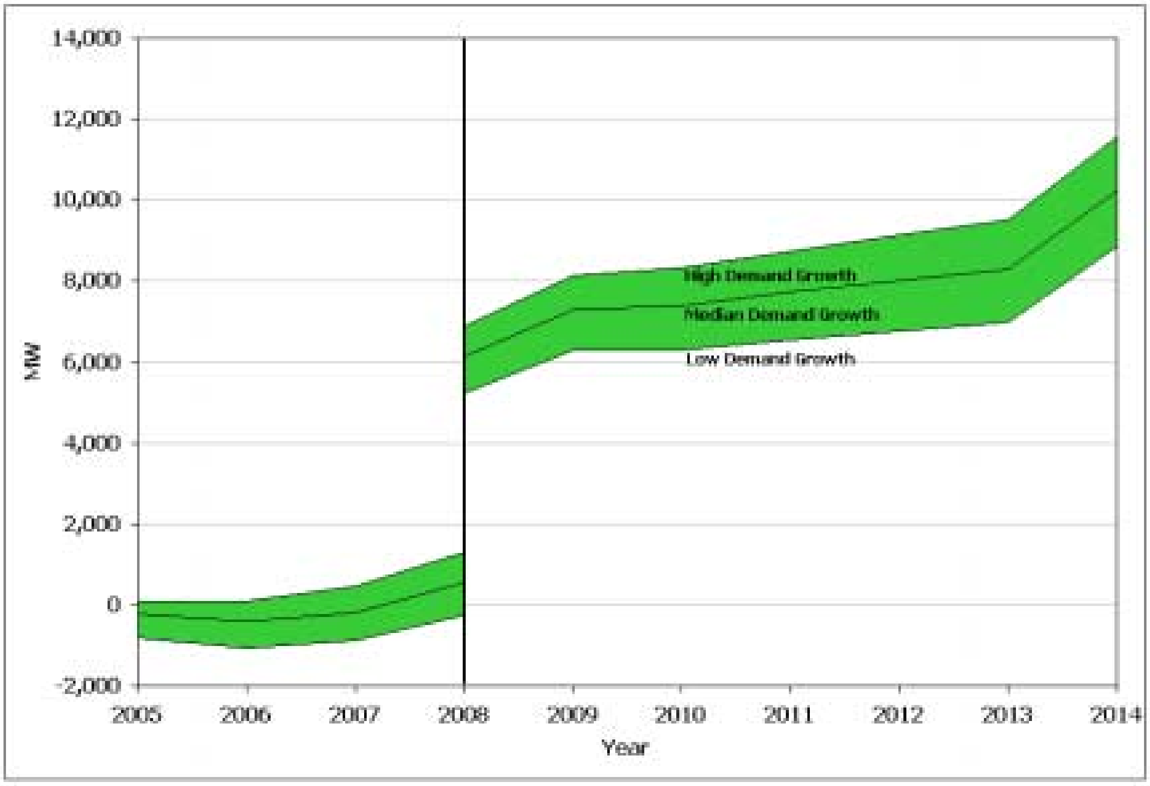
L&C and MARS results indicate that Ontario could be facing a significant supply shortfall. There is an immediate and increasing need for additional resources in Ontario, in order to meet the 0.1 days/year LOLE target in each year of the study period. The only exceptions are for the first three years of the low and median demand growth scenarios. In order to avoid extensive reliance on external supply, the supply shortfall would have to be made up from generation additions and demand-side initiatives within Ontario. In order to implement the Ontario Government's coal phase-out plan, sufficient resources should be in place to replace the coal-fired generation at the time of removal from service, as well as to meet projected demand growth.

Any events that would decrease supply availability or increase demand, such as extreme weather, higher than expected generator forced outages, and lower than forecast hydroelectric resources, would result in increased need for additional supply and extensive reliance on external supply through interconnections.

3.3 The Need for Additional Resources

Figure 3.2 depicts the range of additional resources (supply or conservation) required through the next ten years, in order to meet the 0.1 days/year LOLE standard.

Figure 3.2 Net Requirement for Additional Resources

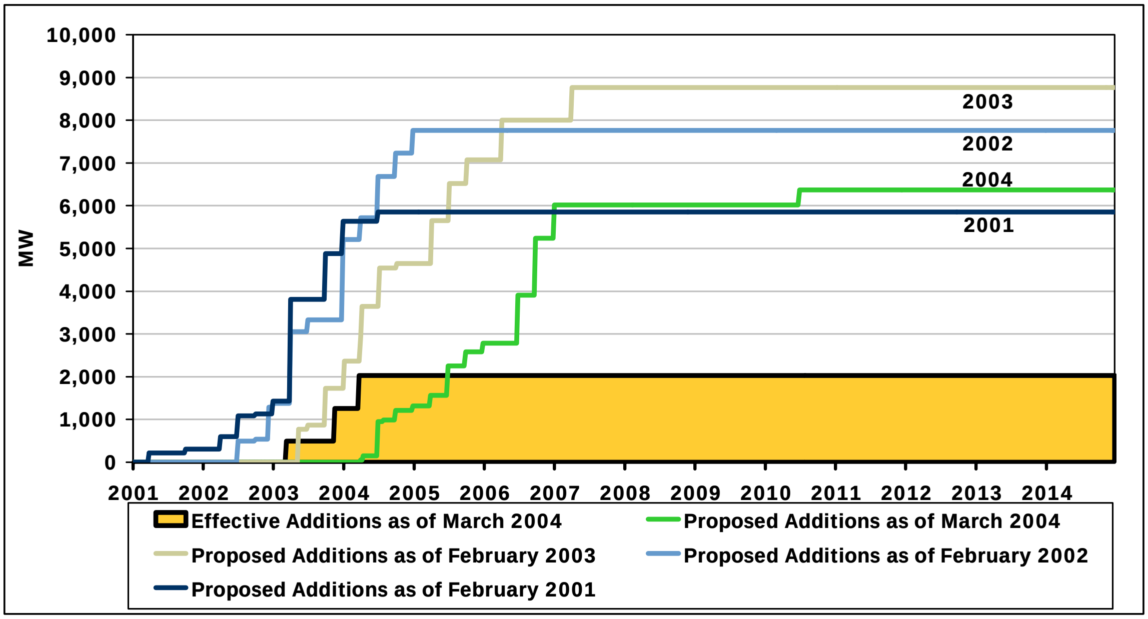


The additional resource amounts shown in Figure 3.2 represent the net amount of supply or demand-side measures required, assuming a net overall capability factor equal to 90 percent of the gross amount implemented, when outages, dependability, coincidence of operation and other aspects are taken into account. In other words, this is the capability required to meet system needs at peak times. The requirement needing to be installed or implemented, therefore, will be 11% higher, reaching as much as 12,850 MW by 2014. Depending on the capability factor of individual resources, the amount of gross additional measures which is required could be higher or lower than that assumed for study purposes. In order to minimize the amount of investment necessary to achieve the required level of supply, consideration must be given to fuel diversity among resources balanced with demand measures. Long-term baseload requirements must be balanced in conjunction with shorter-term peaking and intermediate requirements. High capacity factor resources may need balancing with lower capacity factor resources to achieve social objectives other than cost minimization.

3.3.1 Generation Additions

The amount of generation additions that will materialize over the next few years is critical for the long-term resource adequacy of Ontario. Figure 3.3 depicts the evolution of the proposed new generation additions over the last four years, as reflected by the CAA queue. The in-service dates for most projects have been delayed over the years, and some of the proponents have already withdrawn their projects. The only generation projects completed to date are the TransAlta-Sarnia Cogeneration Project and two reactivated Bruce A units, for a total of approximately 2,000 MW of additional generation. One Pickering A unit was also returned to service in 2003, increasing the available Ontario capacity by about 500 MW (this unit is not included in Figure 3.3). The ATCO-Brighton Beach, Imperial Oil and Northland Power-Kirkland Lake projects have been identified to the IMO as being under construction and are expected to be completed through 2004.

Figure 3.3 Evolution of Proposed New Generation Additions



From Figures 3.2 and 3.3 it is evident that even if all the 6,000 MW of generation projects in the CAA queue were completed in a timely manner, additional generating capacity, demand-side measures and/or reliance on external supply would be required in order to phase out coal-fired generation by 2007. Although the installed rating of these units totals over 6,000 MW, the capability of these projects to meet system peak requirements is estimated to be equivalent to 4,000 MW as a result of the expected dependability of certain forms of generation. In subsequent years, even more resources would be necessary to adequately supply demand growth over the study period.

Two important aspects to be considered regarding generation additions are location and mix. Proper location and a diverse mix of generation resources is crucial for ensuring overall reliability and market efficiency, through dispatch flexibility, reduced vulnerability to fuel supply contingencies and fuel price fluctuations, and through avoiding or alleviating transmission congestion.

3.3.1.1 Locating Coal-Replacement Generation

In order to preserve reliability while the coal phase-out program is implemented, replacement capacity should be in place for each coal-fired generating station by the time it is shutdown. With few exceptions, the replacement capacity must be located in the same electrical zone and have the same overall operational characteristics as the station being retired, in order to avoid transmission adequacy and system operability issues. Lakeview generation can be replaced by generation in the Greater Toronto Area (GTA), east of Milton. In the West Zone, Lambton generation can be replaced locally or from further east along the 500kV system. Nanticoke generation is very impactive on Southwest Zone transmission limits and must be replaced in the Nanticoke vicinity or distributed along the 500kV transmission system between London and Milton. Some of the Northwest generation (Thunder Bay and Atikokan) must be replaced locally in the Northwest to avoid exacerbating transmission limitations.

More details on transmission adequacy issues related to phasing out the coal stations are provided in Section 4.

Generation Proposals by Zone

The zone with the most immediate need for additional generation resources is the **Toronto** zone, especially the **Greater Toronto Area**, where demand growth over previous years exceeded, and is forecast to continue to exceed, most of the other zones in Ontario. New generation proposals totalling approximately 2,300 to 2,700 MW (depending on the alternative selected), have been submitted for the Toronto zone and are listed in Table 2.2. The timely completion of the majority of these projects is urgently needed to forestall potential transmission overloading in the GTA, described in Section 4 and to meet overall system supply requirements. Completion of the refurbishment of the remaining Pickering A units, which are located electrically in the Toronto zone, or construction of an equivalent amount of new generation capacity would further improve zonal and system reliability.

The **West** zone is also experiencing higher demand growth than the Ontario average, due mainly to strong industrial development. The Imperial Oil facility in Sarnia and the ATCO-Brighton Beach facility in the Windsor area are already under construction and expected to become operational during 2004. Another 440 MW of West zone generation projects have been identified to the IMO. Although not required for zonal adequacy, their completion would contribute to alleviating Ontario's potential supply shortfall once coal-fired generation is shutdown.

A total of 1,050 MW of new generation capacity has also been proposed for the **Southwest** zone. This is a good location for new generation capacity, not only from a resource adequacy perspective but also from a transmission adequacy viewpoint. As mentioned earlier, the shutdown of Nanticoke Thermal Generating Station (TGS) would precipitate substantial zonal generation requirements in excess of the amounts proposed.

The 560 MW of wind-powered generation projects proposed in the **Northwest** and **Northeast** zones would provide needed amounts of energy but at times could be limited by transmission constraints and at other times might offer little capacity for meeting peak demands. Their value as a system resource could be enhanced through partnership with suitable hydroelectric resources having storage capability. As long as there is insufficient transmission capacity to always move the available resources from north of Parry Sound into the south, full benefit from these projects will not be realized.

The 465 MW of generation projects proposed for the **Niagara** zone would contribute to reducing reliance on external supply. At times, the output from these projects might be limited by the Queenston Flow West (QFW) interface until sufficient transmission reinforcement occurs, either on the QFW interface directly or through construction of a Niagara to Toronto High Voltage Direct Current (HVDC) link.

Although very few projects have been proposed for eastern Ontario, generation additions in the **East** and **Ottawa** zones would directly support consumers in these zones as well as in the Toronto zone using existing transmission capability.

To a greater or lesser extent, all generation capacity addition projects identified to the IMO through the CAA process would help address the potential supply-demand gap Ontario is facing for the next ten-year period and would reduce reliance on external supply.

Distributed Generation

Distributed generation can play an important role in addressing local supply needs. Not only can it reduce losses and congestion on major transmission interfaces, it can also alleviate local area transmission and distribution reliability concerns. In most cases distributed generation projects can be completed faster than large projects. Distributed generation can be situated anywhere it is not precluded by local transmission concerns; in particular it should be considered for large load centres such as Kitchener/Waterloo, Ottawa, and Windsor, as well as smaller, transmission limited areas, such as Peterborough.

3.3.1.2 New Generation Mix

A diverse generation mix is critical for resource adequacy and market efficiency, through the provision of dispatch flexibility, reduced vulnerability to fuel supply contingencies and fuel price fluctuations.

Baseload Generation

Baseload generation largely consists of nuclear and run-of-the-river hydroelectric resources which cannot routinely be cycled on and off in response to demand fluctuations. These types of generators have limited dispatch flexibility, and, when available to operate, must be run almost continuously at a fixed output, often at or near their full capability. If too much baseload generation is present in the supply mix, the amount of generation can have the potential to exceed the market demand, thereby creating a situation known as unutilized baseload generation (UBG). An analysis of the minimum peak demands in the latter years of the study period suggests that up to approximately 4,000 MW of nuclear and run-of-the-river generation resources could be added to the existing in-service baseload facilities towards the end of the ten-year period without causing undue risk of UBG. This amount will be affected by load growth and any load shifting patterns between on-peak periods and off-peak periods.

Intermediate and Peaking Generation

Existing intermediate and peaking generation in Ontario consists mainly of generation fuelled by coal, gas, oil, and hydroelectric generation with storage capability. New intermediate and peaking generation must be added to the Ontario resource mix in order to implement the coal phase-out plan. The only projects of this nature in the IMO CAA queue are gas-fired. The completion of all the gas-fired generation projects in Ontario would add between 3,500 and 3,800 MW of gas-fired capacity and would more than double the present annual volume of gas consumed in Ontario to produce electricity. Approximately 20% of all the gas consumed in Ontario would then be devoted to electricity generation. The prospects of long-term gas supply at reasonable prices is uncertain. Consideration of other fuel-types with more stable long-term supply potential should be considered in lieu of or in conjunction with gas-fired generation, provided equivalent or lower emission rates can be achieved.

Renewable Generation Resources

Renewable resources consist primarily of hydroelectric, wind, biomass, solar, and geothermal energy sources. These are considered the cleanest and least environmentally impactive of all generation resources. Only wind and a small amount of hydroelectric generation have been proposed to the IMO. Wind generation, by its nature has very little dispatch flexibility; only when the wind blows, can energy be produced. The diversity among projects identified to the IMO will tend to moderate local fluctuations. Further utilization of wind energy can be achieved through partnering with suitable hydroelectric facilities to co-optimize both types of resources. The Energy Conservation and Supply Task Force (ECSTF) Report states that potential exists for large amounts of renewable generation resources to be developed, and that the Province is targeting additions of about 1,350 MW by 2007 and 2,700 MW by 2010 in renewable resources. This potential is substantiated by the approximately 2,350 MW of wind generation proposals submitted to the IMO for Connection Assessment and Approval.

3.3.2 Demand-Side Measures

The IMO has been identifying the suitability of demand-side initiatives as part of the supply picture for several years and believes demand reductions and demand shifting should be vigorously pursued in Ontario, as clean and potentially less expensive ways to reduce future supply requirements. The application of such demand initiatives is virtually unrestricted in location.

Programs would improve the supply-demand balance in three main ways:

- Price-responsive demand which reacts to market price signals and needs not only technical infrastructure for conveying price signals and implementing dispatch but also an appropriately structured market.
- Demand reduction through technological or process efficiency improvements would have beneficial effects on the environment and reduce the need for generation capacity additions through years.
- Shifting the time of use from peak to off-peak periods through demand-response programs would achieve peak demand reductions, influencing electricity prices downward and improving utilization rates of generation resources.

Sections 2 and 4 of the ECSTF Report explored the possible ways to achieve energy conservation and demand response in Ontario. The ECSTF report states that conservation programs could contribute up to 1,350 MW to alleviating future supply requirements.

3.3.3 Interconnections

In real-time system operation, reliance on external supply through interconnections is mutually beneficial to all interconnected systems, for both reliability and market efficiency reasons. During off-peak periods, attractively priced external supply can provide cost savings to the electricity market. During peak hours, due mainly to the non-coincidence of the peak demands with one or more neighbouring systems, external supply can contribute to meeting peak demand.

Two main aspects are relevant to utilization of interconnection benefits: transmission interconnection capability and external supply availability.

Interconnection Capability

Ontario has a coincident import capability of approximately 4,000 MW through its existing interconnections. Transmission projects have been identified to the IMO through the CAA process to enhance the interconnection capability. An HVDC interconnection with Hydro Quebec of 1,250 MW transfer capability would improve interchanges between Ontario and Quebec. Another proposed HVDC interconnection with Pennsylvania would add 990 MW of capability to the interconnections. At this time, both of these projects have high project uncertainty.

Although not yet formally proposed, an upgrade to the Ontario - Manitoba interconnection would give access to hydroelectric capacity from Manitoba. Section 5.7 of the ECSTF Report states that Manitoba has up to 5,000 MW of hydroelectric development potential.

External Supply Availability

An analysis of historical power flows on Ontario's interconnections for the five years prior to 2002 suggests that, outside of summer peak demand periods, up to 1,800 MW of external generation resources can be expected to be available to Ontario. During Ontario's summer peak demand periods of July and August opportunities for imports still exist and imports are still expected to be available despite the fact that many neighbouring systems are often experiencing their peak demand. This is mainly due to the availability of spare capacity from systems that are not summer peaking. From the same analysis, up to 1,400 MW would be expected to be available based on observations during summer peak months in recent years prior to 2002.

The actual hourly import levels experienced from market opening in May 2002 up to February 24, 2004 indicates an average import level of 1,164 MW for all hours. During the 3,044 hours when Ontario demand exceeded 20,000 MW the average import level was 1,544 MW. During the 338 hours when Ontario demand exceeded 23,000 MW the average import level was 2,293 MW, and occasionally reached the Ontario coincident import capability of approximately 4,000 MW.

The Northeast Power Coordinating Council (NPCC) CP-5 study entitled "Review of Interconnection Assistance Reliability Benefits" published in May 1999, provided an assessment that over 2,500 MW of interconnection assistance is reasonably available to the Ontario system when needed. New studies being conducted this year are expected to provide updated guidance for assumptions of tie benefit for Ontario and all other NPCC areas.

Future levels of imports into Ontario will vary depending on several factors, including the availability and willingness of resources in external jurisdictions to supply the Ontario market, and the availability of required transmission capacity. For interconnected supply to contribute to the capacity needs of Ontario, the dependability of supply contracts will need to have an equivalent level of certainty to that of Ontario-based generation.

3.4 Other Considerations and Influencing Factors

There are many factors that could cause the long-term supply-demand balance to change. On the supply side, almost all of the factors would tend to reduce the available generation from that used in the adequacy analysis. Tables A4 to A6 in Appendix A indicate the reserve above requirement values that would result if the available generation resources are lower or higher by 1,000 MW, 2,000 MW and 3,000 MW, respectively, than the forecast amount. They are intended as a starting point for other combinations that one might consider.

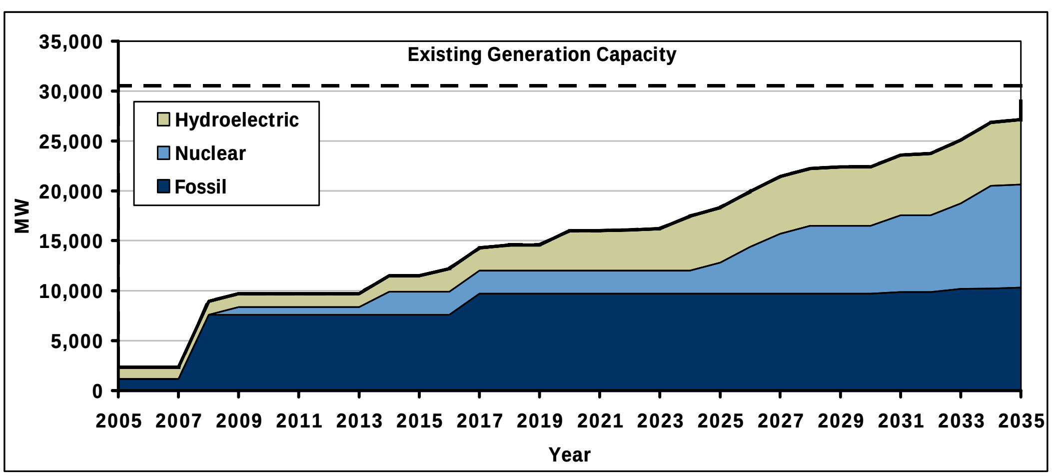
3.4.1 Demand Growth

Higher demand growth than that assumed under the high demand growth scenario, would create an earlier and larger need for additional resources or demand response. Lower demand growth than assumed under the low demand growth scenario above, would delay and lower the need for additional resources. Lower energy and peak demand growth can be achieved through implementation of conservation programs oriented to demand-side management, energy efficiency and peak demand shifting.

3.4.2 Aging Generators

The increasing age of the fleet of Ontario generators will lead to additional retirements or the need for major refurbishment. Age can also contribute to higher incapability factors than assumed in this Outlook. Higher incapability factors are the result of longer planned and/or forced outages. Major refurbishment plans would result in longer planned outages, with increased pressure on the peak demand periods, but with predictable short-term effects on the supply availability and an improvement of long-term reliability. The lack of major refurbishment plans and timely maintenance would increase the forced outage rates of the generators, with unpredictable negative effects on reliability of Ontario generation resources. Figure 3.4 illustrates the cumulative amount of Ontario generating capacity that will exceed the indicated nominal service life over the next 30 years, will potentially need major refurbishment, retire, or require replacement.

Figure 3.4 Capacity Exceeding Nominal Life, Retiring, Or In Need Of Major Refurbishment



The chart was built based on known initial in-service dates for Ontario generators and assumed service life durations for various types of generation resources (65 years for hydroelectric, 40 years for nuclear and fossil), and specific information regarding refurbishment needs from generator owners.

3.4.3 Capacity Sustainability

Experience over the summer has also shown that, even when sufficient capacity is available, its use can be limited because of a lack of energy. An example of this occurs when peaking hydroelectric generation is operated extensively early within a period of time, in response to market demands and, as a result, has insufficient water available in storage reservoirs to support required levels of operation later within that period. An exceptionally dry season can have the same effect. About 24 percent of the capacity within Ontario is hydroelectric with much of it subject to this risk.

- End of Section -

4.0 Transmission Adequacy Assessment

4.1 Introduction

The transmission adequacy assessment provides information to market participants, connection applicants and other stakeholders to assist in planning a reliable transmission system. Where applicable, the assessment also identifies the potential need for IMO-controlled grid investments or other actions by market participants to maintain reliability of the IMO-controlled grid and to permit the IMO-administered markets to function efficiently.

Figure 4.1 provides a simplified depiction of Ontario’s major internal transfer interfaces and Ontario’s points of interconnection with neighbouring control areas. The internal interfaces are also used to define the boundaries of internal zones, called transmission zones. This simplified depiction is used to assist in understanding the analytical evaluations of the Ontario transmission system.

Based on information made available to the IMO, Sections 4.2 and 4.3 describe the transmission projects that are forecast to be in service throughout the ten-year study period and the various transmission projects and existing transmission facilities used in the transmission adequacy assessment. Section 4.4 summarizes other assumptions used in the assessment.

Zonal assessments and summaries are presented in Sections 4.5 to 4.13 starting with the Toronto transmission zone in Section 4.5. The following aspects are covered for each zone:

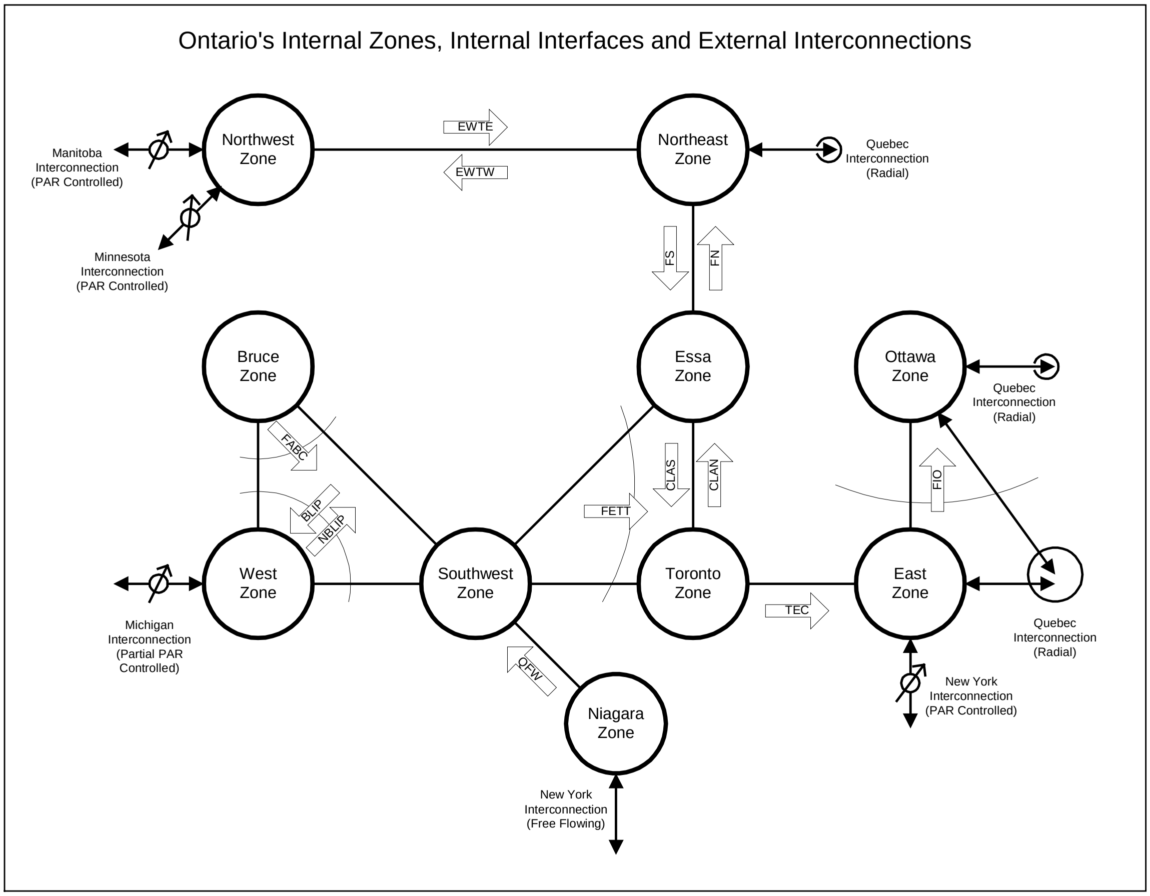
- A supply deliverability assessment of adequacy is performed by examining the impact of specific contingencies on the ability of transmission facilities to supply certain 230 kV and 115 kV loads. Specifically, load pockets greater than 500 MW and load pockets between 250 MW and 500 MW are studied.
- A contingency-based supply reliability assessment is performed by examining the impact of specific contingencies on the ability of the 500 kV and 230 kV autotransformers and transmission circuits to supply loads without exceeding equipment thermal overload capabilities. This assessment is referred to as the “contingency assessment” throughout this section.
- The steady state voltage level adequacy of the 500 kV, 230 kV and 115 kV transmission networks of the IMO-controlled grid is examined.
- As required, a summary of existing and emerging transmission constraints is included. In addition where appropriate, projects in the CAA queue, activities undertaken and/or activities completed in response to these constraints are discussed. Finally, residual needs and possible solutions may also be discussed.

Section 4.13 identifies transmission interfaces that have the potential to regularly become congested and thus reduce market efficiency. Conclusions are provided in Section 5.0.

The methodology used to assess the transmission adequacy is described in the IMO document titled “Methodology to Perform Long Term Assessments” (IMO_REP_0044).

Section 4.0 does not exhaustively assess all areas of the IMO-controlled grid. It is possible that other deficiencies in the IMO-controlled grid may exist or emerge. The IMO continuously monitors, assesses and reports the adequacy of the IMO-controlled grid. If additional concerns are identified they will be managed through existing IMO processes.

Figure 4.1 Ontario's Zones, Interfaces and Interconnections



4.2 Potential New Transmission Facilities

Table 4.1 and Figure 4.2 summarize, in different formats, the new transmission projects in the IMO's CAA process for the Outlook period. Transmitters have provided the information regarding the status of their projects and the in-service dates listed in Table 4.1.

Complete details on these projects can be found on the IMO's web site www.theIMO.com under the "Services - Connection Assessments" link.

Table 4.1 Potential New Transmission Facilities in Ontario

Niagara Zone	**Projected I/S Date**
Reinforce QFW interface.	2007-Q2

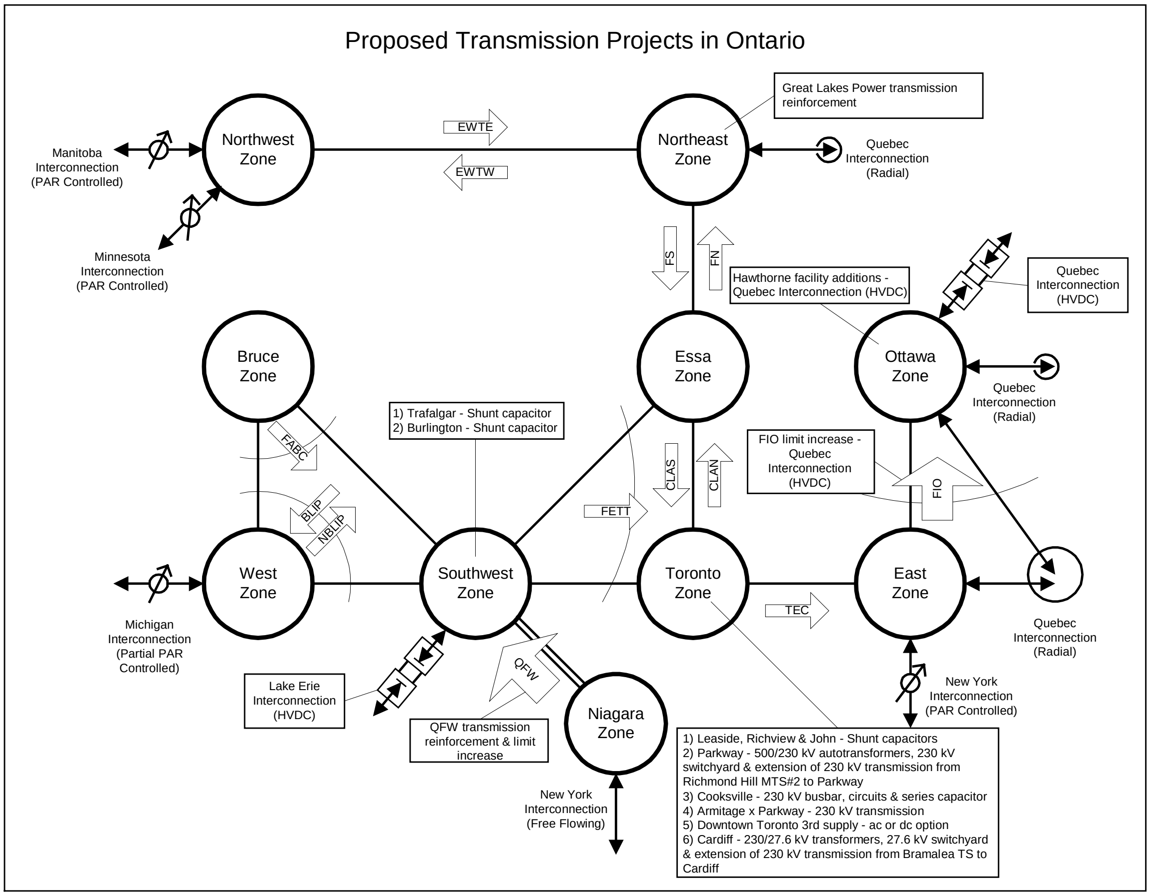
Northeast Zone	**Projected I/S Date**
Reinforce GLP transmission system (stages 2-4).	2005-Q1
Reinforce GLP transmission system (final stage).	2005-Q4
Reinforce GLP transmission system (ampacity upgrade of 230 kV circuit P21G).	2006

Ottawa Zone	**Projected I/S Date**
Hawthorne TS: Build new interconnection to Quebec.	Uncertain

Southwest Zone	**Projected I/S Date**
Burlington TS: Install 300 Mvar shunt capacitor	2005-Q1
Trafalgar TS: Install 300 Mvar shunt capacitor.	2005-Q2
Nanticoke TGS: Build new interconnection to USA.	Uncertain

Toronto Zone	**Projected I/S Date**
Richview TS & John TS: Install 412 Mvar & 99.5 Mvar shunt capacitors, respectively.	2005-Q1
Leaside TS: Install second 125 Mvar capacitor bank.	2005-Q2
Cardiff TS: Build new station; Build 230 kV transmission from Bramalea TS to Cardiff TS.	2005-Q2
Parkway TS: Build new station with one 500/230 kV autotransformer & partial 230 kV switchyard; Build 230 kV transmission from Richmond Hill MTS#2 to Parkway TS.	2005-Q2
Cooksville TS: Build new 230 kV bus, reterminate 230 kV circuits and install series capacitor.	2005-Q3
Parkway TS: Install second 500/230 kV autotransformer and remaining 230 kV switchyard.	2006-Q2
Build new 230 kV transmission between Armitage TS and Parkway TS.	2006-Q4
Build 3rd supply into downtown Toronto - AC or DC option (initial phase/first stage).	2008/2010

Figure 4.2 Potential New Transmission Facilities in Ontario



4.3 Summary of Transmission Network Scenarios Used

In assessing future transmission adequacy, it is necessary to make a number of assumptions regarding the network configurations that will be available for operation. Generally, two different scenarios were assumed in this Outlook regarding the transmission network: an **Existing Transmission Network Scenario** and a **Planned Transmission Network Scenario**.

Under the **Existing Transmission Network Scenario** the transmission network studied consists of the existing transmission network as of December 2003 plus all the Ontario-Michigan phase shifters assumed installed and regulating active power flow.

Under the **Planned Transmission Network Scenario** the transmission network studied consists of the Existing Transmission Network Scenario plus planned transmission facility additions in the CAA queue. The planned transmission facilities include projects scheduled for service in 2004 and projects with an expected in-service date of 2005 or later. Table 4.1 provides a list of proposed transmission projects with an expected in-service date of 2005 or later.

The years 2005 and 2006 are used for the supply deliverability, contingency and steady state voltage adequacy assessments involving load flow studies to show the near-term benefits of certain proposed transmission facility additions. The year 2010 is used for assessments involving load flow studies to identify any long-term concerns with the transmission system.

In 2005 for the Existing Transmission Network Scenario (ETRS), studies show that the system is not adequate or secure without the addition of proposed reactive resources in the Southwest and Toronto zones. Since reactive resources are required in these zones before the retirement of Lakeview TGS, load flow studies with the ETRS were not performed for later years of the Outlook period.

For 2005 assessments involving load flow studies, the Planned Transmission Network Scenario (PTNS) includes all transmission projects in the CAA queue with an expected in-service date before 2005 summer peak conditions. Some of the included projects are transmission reinforcement (stages 1-4) in the Northeast zone, reactive additions in the Southwest and Toronto zones, and a single 500/230 kV autotransformer at the new Parkway Transformer Station (TS) in the Toronto zone.

For 2006 assessments involving load flow studies, the PTNS includes projects studied for 2005 plus transmission reinforcement (final stage) in the Northeast zone and a second 500/230 kV autotransformer at Parkway TS, 230 kV transmission between Armitage TS and Parkway TS, a new 230 kV bus at Cooksville TS, and a new Cardiff TS in the Toronto zone.

For 2010 assessments involving load flow studies, the PTNS includes projects studied for 2005 and 2006 plus transmission reinforcement on the QFW interface between the Niagara and Southwest zones.

For the congestion assessment, the years 2005 and 2010 are studied with the Existing Transmission Network Scenario (ETNS) and not the PNTS. This assessment does not require the addition of the proposed reactive resources in the Southwest and Toronto zones for the studies to solve when Lakeview TGS is retired. In addition, as detailed in Section 4.13, the forecast of congestion on the major interfaces in southern Ontario is low. Most of the transmission projects, except the QFW interface upgrade and the Downtown Toronto 3rd supply – Direct Current (DC) option projects, in the CAA queue are not expected to materially change the power flows on the major interfaces.

4.4 Summary of Assumptions Used

Transmission adequacy is assessed using various resources and demand scenarios combined with the transmission network scenarios described in Section 4.3. For the supply deliverability, contingency and steady state voltage adequacy assessments involving load flow studies, summer peak conditions under the High Growth, Extreme Weather Demand Scenario are studied. For congestion assessment, using the Multi-Area Production Simulation (MAPS) software program, the Median Growth, Normal Weather Demand Scenario is used. These demand scenarios are described in the IMO document titled “Ontario Demand Forecast from January 2005 to December 2014” (IMO_REP_0173).

In addition to the demand considerations for the transmission adequacy assessments involving load flow studies, a modified Reference Resource Scenario (mRRS) is studied with the various transmission network scenarios described in Section 4.3. The Reference Resource Scenario is described in Section 2.3 of this Outlook. Depending on the year of study, the mRRS assumes a certain availability of the Nanticoke (or the equivalent thereof), Pickering and Darlington units from an available total of eighteen units - Nanticoke (8 units), Pickering (6 units) and Darlington (4 units). The following availability assumptions are used:

- 2005 – 6 Nanticoke units, 4 Pickering units and 3 Darlington units
- 2006 – 6 Nanticoke units, 5 Pickering units and 3 Darlington units
- 2010 – 7 Nanticoke units (or equivalent), 5 Pickering units and 4 Darlington units

The availability assumptions for the Nanticoke, Pickering and Darlington units are used to stress the capability of the transmission system. Finally, for all years studied, scheduled imports of 1,000 MW from Michigan, 1,000 MW from New York and 400 MW from Quebec plus 1,000 MW of Lake Erie Circulation (LEC) are assumed. With Michigan phase shifters regulating, 600 MW of LEC is blocked. As a result, the net flows from Michigan and New York are 600 MW and 1,400 MW, respectively.

Other assumptions used in the assessments are detailed in the following paragraphs.

The active power values from the demand scenarios for the 2005, 2006 and 2010 load flow studies have been uniformly scaled within each zone. This assumption may skew load distribution in the future because it does not distinguish between high and low growth pockets within zones. Some element overloads that depend strongly on the scaling assumptions (e.g. 230/115 kV autotransformers) may not materialize.

The reactive power values for the 2005 and 2006 load flow studies have also been uniformly scaled within each zone to maintain the power factor from the summer 2003 ‘base case’ load flow with all low voltage shunt capacitor banks in-service. For the 2010 load flow study, the reactive power values have been scaled within each zone to provide a 0.93 power factor at the defined meter point.

For the supply deliverability assessment, the assessment focuses on load pockets of 250 MW or greater. The assessment determines if a supply interruption occurs for a permanently faulted double circuit line. Supply is deemed inadequate for any interruption of load pockets greater than

500 MW, and for interruption of load pockets between 250 and 500 MW where there is no means of sectionalizing transmission facilities to restore the load within 30 minutes of the contingency.

For the contingency assessment of transmission circuits, post-contingency flows on circuits are examined for single element and double element contingencies. For single element contingencies, a circuit is noted as a potential concern if the flow exceeds its continuous ratings. For double element contingencies, a circuit is noted as a potential concern if the flow exceeds its 15-Minute Limited Time Rating (LTR).

For the contingency assessment of autotransformers, the impact of a transformer contingency on specific 500/230 kV and 230/115 kV transformation points of the IMO-controlled grid is examined. Upon loss of an autotransformer within a transformation point, the remaining autotransformers at the transformation point should continue to supply the required load. For those 230 kV autotransformers that feed radial loads, adequacy is determined by comparing total station or group load with the sum of 10-Day LTRs with one autotransformer out of service. For 500 kV and those 230 kV autotransformers that do not feed radial loads, outage distribution factors based on the Existing Transmission Network Scenario are used to determine the post-contingency flow on the remaining autotransformers. The resulting post-contingency flow on each autotransformer is then compared to its 10-Day LTR to determine if there is a concern.

4.5 Toronto Zone

Transmission Reinforcement within the GTA

There are a number of immediate and emerging concerns regarding the ability of the existing transmission facilities in the GTA to maintain an acceptable level of supply reliability to this area.

The issues of immediate concern include the following:

- the scheduled shutdown of the Lakeview generating station on April 30, 2005,
- the ability of the transmission system in the Leaside sector[1] to support the forecast load growth in that area, and
- the ability of the existing transmission facilities to supply the rapidly growing load in the Newmarket and Aurora areas.

In addition, the following emerging supply issues also require attention:

- the reinforcement of the existing radial supplies to the northern Mississauga, Brampton, Milton, the Town of Halton Hills, Vaughan and northern Toronto areas,
- the reinforcement of the existing radial supply to the southern Mississauga and southern Oakville areas, and
- the enhancement of the supply capability of the western GTA and the combined Southwest and Toronto zones (specifically an increase in the capacity of the injection points and/or the generating capacity available within the area).

[1] The Leaside sector is the area of Toronto bounded approximately by of Victoria Park Avenue on the east, Eglinton Avenue on the north, Avenue Road/University Avenue on the west and north of Lake Ontario.

Impact of Shutdown of Lakeview TGS

Lakeview TGS is capable of supplying approximately 1,148 MW and 600 Mvar with all four of the existing generating units in-service. Once it is shutdown, the resulting supply deficiency in the western half of the GTA will result in increased transfers through the four autotransformers at Claireville TS and along the 230 kV corridors into Richview TS. However, during peak load periods, with Lakeview TGS still in-service, the autotransformers at Claireville are already loaded beyond their continuous ratings of 750 MVA. They would therefore be unable to accommodate the increased transfers resulting from the shutdown of Lakeview. Consequently, in the absence of any remedial measures to address the overloading of the Claireville autotransformers, it will either be necessary to retain Lakeview temporarily or expect supply interruptions possibly during the summer of 2005.

Possible remedial measures could have included the installation of additional autotransformer capacity at Claireville TS and/or the incorporation of new generating capacity within the western GTA. However, it is now generally accepted that there is insufficient time available to complete the work involved before the summer of 2005.

However, one timely remedial measure has been identified to solve the overloading of the autotransformers at Claireville TS; namely, advancing the installation of the first 500/230 kV autotransformer at Parkway TS to May 2005.

Parkway TS

In response to the IMO's concerns described in the previous 10-Year Outlook regarding the supply to the Vaughan, Richmond Hill and Markham areas, Hydro One responded with a proposal to establish a new 230 kV switchyard at Parkway Junction and to connect it to the 500 kV system via two 500/230 kV autotransformers. In addition, this project also involves the construction of a 230 kV double circuit line from Richmond Hill MTS #2 to Parkway TS. The earliest completion date for the new Parkway TS was stated to be May 2006.

However, it was then realized that extending the existing 230 kV V71R and V75R circuits from Richmond Hill through to Parkway and connecting these circuits to the first autotransformer would provide substantial relief for the critical autotransformers at Claireville TS. Analysis showed that this arrangement (without Lakeview TGS) would restore the transfers through Claireville TS to approximately the same levels as are presently experienced during peak load periods with Lakeview TGS still in-service. Hydro One is therefore proceeding to place the initial autotransformer at Parkway TS in-service by May 1, 2005, to coincide with the shutdown of Lakeview TGS. The remainder of the work at Parkway TS would then proceed as originally scheduled, with completion targeted for May 2006.

Reactive Compensation in the Western GTA

While the initial phase of the development of Parkway TS is expected to address the overloading of the existing autotransformers at Claireville TS resulting from the shutdown of Lakeview TGS, it will not provide the reactive power support required to maintain an acceptable voltage profile throughout the western portion of the GTA. To provide this support, Hydro One is planning to install the following shunt capacitor banks before 2005:

- Burlington TS: 230 kV, 300 Mvar
- Richview TS: 230 kV, 412 Mvar
- John TS: 115 kV, 100 Mvar

In addition, it is necessary to have either two of the existing generating units at Lakeview TGS converted to synchronous condenser operation or a further 300 Mvar shunt capacitor bank installed on the 230 kV system at Trafalgar TS. This additional reactive support, which would need to be in-service by May 2005, would be required to maintain secure system voltages while supplying the extreme-weather loads that have been forecast for summer 2005, based on the unit availability assumed in the modified Reference Resource Scenario for Nanticoke TGS, Pickering Nuclear Generating Station (NGS) and Darlington NGS - three generating stations that are critical to the supply to the GTA.

Hydro One is also developing a scheme that would allow the automatic voltage control operation of transformers within specific areas of the system to be inhibited, upon instruction from the IMO. This scheme is expected to be available by May 1, 2005. The intent is that this scheme would only be deployed during emergency conditions when a critical component, such as one of above new capacitor banks that Hydro One is planning to install, is unavailable.

On the assumption that the following work can be completed to coincide with the shutdown of Lakeview TGS on April 30, 2005, then the entire GTA demand can be supplied in 2005:

- the initial phase of Parkway TS with the installation of the first autotransformer,
- the installation of the shunt capacitor banks at Burlington TS, Richview TS and John TS,
- the installation of a shunt capacitor bank at Trafalgar TS, or the conversion of two of the generating units at Lakeview TGS to synchronous condenser operation, and
- the installation of a scheme that would block the automatic voltage control operation of transformers within specific areas of the system.

Second Phase of the Development of Parkway TS

The second phase of the approved development of Parkway TS, involving the installation of the second autotransformer and the construction of a new 230 kV bus at Parkway TS during the spring 2006, will result in a further small reduction in the transfers through the Claireville autotransformers and a significant reduction in the transfers through the autotransformers at Cherrywood TS.

For 2005 under summer peak conditions, Richmond Hill and Vaughan loads supplied from 230 kV circuits V71R and V75R are at risk of a supply interruption greater than 500 MW for a double circuit contingency involving V71R and V75R. The new Parkway 230 kV bus will allow these circuits to be reterminated at Parkway. This new connection arrangement and the use of a normally open point between the Vaughan and Richmond Hill transformer stations will allow the Vaughan loads to be supplied from Claireville and the Richmond Hill loads to be supplied from Parkway. This significantly reduces the load levels exposed to a double circuit line contingency and thereby addresses the IMO’s 500 MW supply deliverability guideline concern for these loads.

The new Parkway 230 kV bus will also allow for a retermination of the loads currently supplied by 230 kV circuits C11R and C12R. For 2005 summer peak load conditions prior to the retermination of these loads, a double circuit line contingency involving C11R and C12R could result in a supply interruption greater than 500 MW. This violates the IMO’s 500 MW supply deliverability guideline. The new switching arrangement will significantly improve the supply reliability for these loads in the Vaughan, Richmond Hill and Markham areas.

Supply Capability of the Western GTA

Because the 2006 phase of the development of Parkway TS will provide only limited additional relief for the autotransformers at Claireville TS, compared with that obtained upon completion of the initial phase, the supply situation for the western GTA will show only a marginal improvement. Analysis has shown that this improvement is expected to be adequate for the High Growth, Extreme Weather demand forecast loads only through the summer of 2006.

However, enhanced supply capability will be required prior to the summer of 2007 if adequate levels of supply reliability are to be maintained within the western GTA under extreme weather conditions with the unit availability assumed in the modified Reference Resource Scenario for the Pickering, Darlington and Nanticoke generating stations. Specifically, this enhanced supply capability is needed to ensure that:

- the combined, continuous rating for the four auto-transformers at Claireville TS is respected, pre-contingency, and
- acceptable voltages can be maintained, post-contingency.

It should be noted that while the 10-Day Limited Time Rating with only three of the autotransformers available at Claireville TS would be lower than the continuous rating with all four units in-service, the latter would more restrictive because the transfer through Claireville TS is affected by the number of autotransformers in-service.

Acceptable post-contingency voltages are sensitive to assumptions regarding future load growth within the area. Maintaining acceptable loadings on the remaining autotransformers at Claireville, following the loss of one autotransformer, is based on the optimistic assumption that a failed autotransformer can be replaced within ten days. If the autotransformer cannot be replaced within 10 days, it may be necessary to cut load. To mitigate the risk associated with these assumptions, the IMO considers it prudent to ensure that the supply capability of the western GTA is enhanced prior to the summer of 2006.

The enhanced supply capability could involve the incorporation of additional generation capacity within the western GTA (proposals have been received for Sithe-Goreway, Sithe-Mississauga, Boralex-Mississauga and Greater Toronto Airport Authority-Pearson International Airport) and/or the installation of new transmission facilities to enhance the capacity of the principal injection points for this area.

Cherrywood TS

It should also be noted that since the last 10-Year Outlook was issued, work has commenced on the separation of the paired autotransformers at Cherrywood TS. This work is scheduled to be completed by May 2004. This separation is important, particularly with fewer generating units available at Pickering NGS, since without it, with heavy transfers through Cherrywood TS, any contingency that would result in the loss of a pair of autotransformers could cause overloading of the remaining pair.

Once each of the 500/230 kV autotransformers at Cherrywood TS has been separately terminated, then together with the reduced transfers that will occur through Cherrywood TS upon completion of Parkway TS in May 2006, the situation at Cherrywood TS will improve significantly.

Supply to the Newmarket and Aurora Areas

To meet the increasing load in the Newmarket and Aurora areas, Hydro One is proposing to construct a new 230 kV transmission line from either the new Parkway TS or from Claireville TS to Armitage TS and to establish a new Armitage No. 3 TS. These new facilities are expected to be in-service by 2006-Q4.

The new 230 kV line would also provide additional load meeting capability to accommodate the new Vaughan MTS # 4 that is planned to be in-service by 2008-Q2.

Supply Deliverability to Northern Mississauga, Brampton, Vaughan and Northern Toronto Areas

Loads supplied by radial 230 kV circuits V74R and V75R could exceed 250 MW under extreme summer conditions. This load pocket would be at risk of a supply interruption for a double circuit line contingency with no switching ability to restore supply to the loads within 30 minutes of the event. This violates the IMO's 250 MW supply deliverability guideline.

Supply Deliverability to the Northern Mississauga, Brampton, Milton and the Town of Halton Hills Areas

Hydro One is proposing to extend the existing 230 kV line that supplies Bramalea TS from Claireville TS to the new Cardiff TS. This new TS, which will supply the increasing load in northern Mississauga, is expected to be in-service by the spring of 2005.

All of these areas in the northern portion of the western GTA continue to be supplied by radial double circuit lines:

- Pleasant TS and Jim Yarrow TS with a peak load approaching 400 MW, via the radial 230 kV circuits R19T and R21T
- Trafalgar TS (the 230/27.6 kV switchyard), Halton TS and Meadowvale TS with a peak load in excess of 300 MW, via the radial 230 kV circuits T38B and T39B
- Bramalea TS and the new Cardiff TS with a peak load approaching 400 MW, via the radial 230 kV circuits V72R and V73R

It should also be noted that while Pleasant TS and Jim Yarrow TS are supplied via a radial connection, this connection is tapped directly on to the section of circuits R19T and R21T between Richview TS and Trafalgar TS. Since this section of circuits R19T and R21T supplies one of the three transformers at Erindale TS and one of the two transformers at Tomken TS, the additional load that would be at risk to a double circuit contingency involving these two circuits would total approximately 350 MW.

The combined peak load supplied from circuits R19T and R21T that would be at risk to a supply interruption resulting from a double circuit contingency involving these circuits would therefore be approximately 750 MW. This is well in excess of the IMO's 500 MW supply deliverability guideline and would represent the highest concentration of load in Ontario that is supplied from a single double circuit line.

With the increases in loading on the various transformer stations in these areas, maintaining acceptable post-contingency voltages under contingency conditions involving one of the circuits of each pair is also becoming difficult. This is expected to require additional reactive compensation to be installed, in combination with a program to increase the capacity of the step-down transformers at the more heavily loaded transformer stations.

Furthermore, while the amount of load supplied from circuits T38B and T39B and from circuits V72R and V73R that would be interrupted in the event of a double circuit contingency would not violate the IMO's 500 MW supply deliverability guideline, the inability to restore the supply quickly following a permanent double circuit fault (such as the failure of one of the transmission structures) remains a concern.

In addition, 230 kV circuits R14T and R17T supply the remaining two of three transformers at Erindale TS and the remaining one of the two transformers at Tomken TS. Under extreme summer peak conditions, these loads could also exceed 500 MW and would be at risk to supply interruption for a double circuit line contingency. This would violate the IMO's 500 MW supply deliverability guideline.

Hydro One is examining various options to address the IMO's concerns in this area of the GTA.

Supply to the Southern Mississauga and Southern Oakville Areas

Hydro One is proposing to establish a new 230 kV bus at Cooksville TS and to construct a new connection from Applewood Junction into Cooksville TS, to allow the existing arrangement at Applewood Junction to be reconfigured. This will then allow the existing connections between Applewood Junction and Lakeview TGS to be disconnected and left idle.

In addition, it is proposed to install series capacitors in the single 230 kV circuit that connects Richview TS to Cooksville TS, to increase its contribution to the supply within the area. The net result of all of these changes will be to decrease the very high transfers that will occur on the existing circuits between Richview TS and the Manby TS once Lakeview TGS is shutdown.

The new switching arrangement at Cooksville TS will improve the supply reliability to the loads in southern Mississauga and southern Oakville by substantially reducing the effect of contingencies involving circuits L23CK and L24CR. Furthermore, establishing the new 230 kV bus at Cooksville TS will allow one of the connections to the two transformers at Cooksville TS to be relocated so that it is no longer subject to a supply interruption in the event of a double circuit contingency involving circuits B15C and B16C to Oakville TS. This will reduce the amount of load that can be interrupted due to a double circuit contingency from approximately 400 MW to around 300 MW.

This work is anticipated to be completed by 2005-Q3.

While this realignment of the supply arrangement for Cooksville TS would be a significant improvement, the IMO remains concerned about the absence of any alternative supply for the remaining loads in southern Mississauga and southern Oakville should a permanent line fault involving the loss of both 230 kV circuits B15C and B16C occur.

Supply to Downtown Toronto

The Leaside sector (the eastern portion of the supply to downtown Toronto), including the 230 kV transmission corridor between Cherrywood TS and Leaside TS, remains the most critical of the two supply corridors into downtown Toronto. IMO studies show that the post-contingency power flow on circuit C14L will be above its continuous rating on loss of circuit C16L. Based on the latest load forecast for the City of Toronto, enhancement to the corridor's load meeting capability will be necessary before the summer of 2008.

In addition, under extreme summer peak conditions, IMO studies indicate that the Leaside 230/115 kV transformation point could exceed its 10-Day Limited Time Rating transfer capability on the loss of an autotransformer. Based on the latest forecast for the City of Toronto, relief for the autotransformers at Leaside will be necessary before the summer of 2008. However, recognizing the uncertainty inherent in such a forecast, and the vital need to maintain supply reliability in this area, the IMO considers it prudent to ensure that additional supply capability is available beginning in the summer of 2006. This additional supply capability can take the form of some combination of additional transmission capability, new generation and increased demand response.

Should the proposed 550 MW Portlands Energy Centre Project be developed by 2006, this would address the above concerns. Alternatively, Hydro One could proceed with their plans to increase the capacity of the Leaside sector by providing a new source of transmission supply.

The Manby sector[2], and in particular Manby West TS, (which supplies the southwestern portion of downtown Toronto), is also heavily loaded, although some spare capacity is still available at both Manby TS's. This is especially important because it allows a limited amount of load to be transferred from the Leaside sector to both Manby East TS and Manby West TS under emergency conditions.

It should be emphasized, however, that following the shutdown of Lakeview TGS in 2005, the capability to transfer approximately 125 MVA of load to Manby West TS on an emergency basis during peak load periods will no longer be available because of post-contingency restrictions on the circuits between Richview TS and Manby TS. However once the planned changes at Cooksville TS have been completed in May 2006, this capability will be restored, although it will gradually diminish with increases in the loads in the western portion of downtown Toronto.

In addition, because the Leaside and Manby sectors cannot be permanently interconnected without exceeding the fault interrupting capability of some of the existing equipment, load can only be transferred depending on outage conditions and demand levels in discrete blocks. This means that only that portion of the load at Esplanade TS that is supplied from 115 kV circuit H2JK can be transferred to Manby West TS, while all of Dufferin TS or Dufferin TS and Bridgman TS can be transferred to Manby East TS.

To enhance the transfer capability between the Leaside sector and Manby West TS, Hydro One is proposing to advance a portion of their plan for a third supply to downtown Toronto. This will involve the installation of two new cabled circuits from John TS through to Esplanade TS and is expected to be completed before the summer of 2008.

This connection would then permit various combinations of the loads at Terauley TS and Esplanade TS to be transferred from the Leaside sector to Manby West TS, as well as allowing combinations of the loads at John TS and Strachan TS to be transferred from Manby West TS to the Leaside sector. However, it must be recognized that with continuing increases in the regular load that is supplied from Manby West TS, the capability to accommodate load transfers from the

[2] The Manby sector is the area of Toronto bounded approximately by the Etobicoke Creek on the west, Eglinton Avenue on the north, Avenue Road /University Avenue on the east and north of Lake Ontario.

Leaside sector will diminish over time and therefore reduce the effectiveness of this connection between John TS and Esplanade TS.

Because of the fault level restrictions that prohibit interconnecting the Manby and Leaside sectors, the proposed connection will still require discrete amounts of load to be transferred between the two sectors. A proposal that would overcome this restriction is therefore being considered. The proposal involves constructing another connection from Esplanade TS through to Hearn Switching Station (SS) and installing a back-to-back DC converter at Hearn SS.

This would allow controlled flows to occur between the two sectors while not contributing to the existing fault levels, thereby allowing utilization of the existing transmission facilities. Furthermore, since this link would remain permanently in-service, it would be possible to respond quickly to contingencies to restore loadings to levels that would respect the Limited Time Ratings of the existing transmission facilities which would further improve the overall reliability.

Should additional generation capacity, such as the Portlands Energy Centre Project at the Hearn TGS site, be developed and incorporated at 115kV system into the Leaside sector, then a link between John TS and Hearn SS, via Esplanade TS, would allow a portion of its output to be directed into the Manby sector to enhance its load meeting capability. This would be particularly beneficial whenever facilities in the Manby sector are unavailable and its supply capability is constrained.

Furthermore, without the John-Esplanade-Hearn link, any additional generation capacity that may be incorporated at 115 kV into the Leaside sector would only be of direct benefit to that sector. Although the concerns regarding the Manby sector are less critical than those facing the Leaside sector, it is becoming increasingly difficult to schedule outages on the major items of equipment, especially the autotransformers at Manby West TS, without jeopardising the reliability of the supply. These difficulties will become even more acute once Lakeview TGS is shutdown.

The completion of the John-Esplanade-Hearn link, in conjunction with the development of new generation capacity in the Leaside sector, would therefore allow both the Manby and Leaside sectors to derive full benefit from any new generation capacity that might be incorporated into the Leaside sector.

Third Supply to Downtown Toronto

As mentioned in the 2003 10-Year Outlook, Hydro One has submitted proposals for the development of a third supply for downtown Toronto. Two options remain under consideration; a DC option involving the staged development of two DC cables under Lake Ontario to Sir Adam Beck Generating Station (GS) in Niagara Falls, and an alternating current (AC) option involving staged 230 kV AC connections between Manby TS and Esplanade TS.

These proposals have since evolved to incorporate the proposed initial link between John TS and Esplanade TS, and its possible extension to Hearn SS.

Stages 1 and 2 of the DC option are now identical, each involving a 500 MW DC connection. Stage 1 is currently planned to be in-service by the spring 2010, while Stage 2 would not be completed until approximately 2020. However, should significant amounts of new generation capacity be developed within the GTA, then these dates could be deferred.

The first stage of the alternative option, which is based on a hybrid AC-DC arrangement, would involve installing two 230 kV AC cabled connections between Manby TS and John TS, where they would connect to the two cables of the initial John-Esplanade-Hearn link. The two cables of the John-Esplanade-Hearn link, which would be operated initially at 115 kV, would then be operated to 230 kV upon completion of the first stage of the development.

The second stage of the hybrid AC-DC option would occur once the loads at John TS and the Railway lands area have increased sufficiently to warrant further reinforcement of the transmission facilities. This stage would involve uprating one of the existing 230 kV cables between Riverside Junction and John TS that is presently operating at 115 kV, to 230 kV operation, and extending it through to a new TS in the Railway lands area.

Presently, the IMO considers the DC option to be superior to the hybrid AC-DC option since the latter option would require the existing transmission facilities within the western GTA to be reinforced to support the additional load that would have to be supplied from them. In particular, it is expected that additional 230 kV connections would need to be established between Richview TS and Manby TS and that additional autotransformer capacity would need to be installed at Claireville TS. Furthermore, it is expected that the installation of any additional autotransformers at Claireville TS would result in increased the fault levels at the Claireville 230 kV bus that would require it to be operated open. This would require substantial changes at Claireville TS as well as the termination of the idle 230 kV circuit between Claireville TS and Richview TS.

However, should substantial new generation capacity be developed within the western portion of the GTA, then, depending on its location, there could be an opportunity to defer most, if not all, of the changes that are expected to be required to the existing transmission infrastructure.

The DC option, by comparison, would require only minimal changes to the existing transmission infrastructure since part of the downtown Toronto load would be supplied directly from the generating capacity in the Niagara zone. The net effect would be a direct transfer of this load on to the transmission system in the Niagara zone.

DC Facilities

Presently, there are no DC facilities in-service on the IMO-controlled grid so there is no experience in the operation and maintenance of this type of equipment. The IMO would therefore support the development of the John-Esplanade-Hearn link, together with the back-to-back DC converter, as soon as possible to provide a period in which to gain operational experience and evaluate the performance of the DC facilities before any decision is made on the subsequent stages of the third supply for downtown Toronto.

Supply Capability to the Combined Southwest and Toronto Zones

IMO analyses show that load flow simulations do not solve when the Beck 2, Nanticoke, Pickering and Darlington and other existing generating units in southern Ontario approach their maximum reactive power capability, even though, the Lambton, Bruce and Lennox generating units are not near their full reactive capability. Starting with the Planned Transmission Network Scenario for 2006 with 6 Nanticoke, 5 Pickering and 3 Darlington units in-service, the demand for the Southwest and Toronto zones was increased until the load flow could not solve. The highest combined Southwest and Toronto zone demand that could be satisfied is approximately 15,700 MW for the load power factor and demand distribution modeled. For a 5% increase in the reactive power consumption in these zones, the highest combined demand that could be satisfied drops to approximately 15,400 MW. Using the High Growth, Extreme Weather Demand

Scenario, the combined Southwest and Toronto zone demands are forecast to reach these levels starting as early as the summer of 2006. With the Median Growth, Normal Weather Demand Scenario, the combined zone demands are forecast to reach these levels starting as early as the summer of 2007. Generally, when the combined Southwest and Toronto zone demand is greater than 15,000 MW, the Ontario demand is greater than 27,000 MW.

These analyses suggest even with the current planned reactive additions for the Southwest and Toronto zones, additional reactive resources will be required in these zones later in the Outlook period for summer peak demands and certain generator outage conditions. While additional 'static' devices such as shunt capacitors would help maintain acceptable voltage levels, these zones will also need 'dynamic' compensation from generators or synchronous condensers to prevent system voltage collapse.

The pre-contingency 500 kV voltage at Milton Switching Station is below present minimum requirements in the load flow studies for 2005, 2006 and 2010 at extreme summer peak demands. This result supports the need for additional reactive resources in the Southwest and Toronto zones.

Furthermore, the supply capability to these zones is very dependent on 500 kV circuits B560V and B561M. These circuits, which are part of the Flow Away from Bruce Complex (FABC) transmission interface, are critical to the amount of power that can be delivered from the Bruce Nuclear Generating Station. Under peak conditions, a B560V and B561M double circuit contingency would result in the interruption of high power flows into the Southwest and Toronto zones on these circuits. The ability of remaining injection points to supply these zones post-contingency could be inadequate. To mitigate the adverse effects of this double circuit contingency, transmission reinforcement such as building new 500 kV transmission in parallel with B561M and B560V or strengthening the existing 230 kV transmission circuits that run in parallel to B561M and B560V would increase the transfer capability into these zones. Resource additions in the Southwest and Toronto zones would delay the need for transmission reinforcement.

4.6 Southwest Zone

Impact of Shutdown of Nanticoke TGS

The Government of Ontario has indicated its intention to shutdown all coal-fired generating stations by the end of 2007. System reliability thereafter will depend on sufficient replacement generation being available. The Nanticoke TGS with a reactive power capability of approximately 2,200 Mvar and its strong connection to the 500 kV transmission network is critical to secure operation of the IMO-controlled grid by providing voltage and stability support. In particular, several interface limits, namely Buchanan Longwood Input (BLIP)/Negative Buchanan Longwood Input (NBLIP) and FETT, and the output capability of the Bruce Nuclear Generating Station (FABC) via the current transmission infrastructure are dependent on the number of Nanticoke units in-service. Without substantial replacement generation at or near Nanticoke along the 500 kV transmission corridors to London and Toronto, significant operating restrictions will occur in southern Ontario, which could in turn jeopardize resource adequacy. Transmission reinforcements from the Bruce zone and additional reactive capability in the Southwest zone could alleviate some of these restrictions.

Supply to the Detweiler Operating Area

In last year's 10-Year Outlook, supply reliability concerns were identified for the Detweiler operating area, encompassing the municipalities of Kitchener-Waterloo, Cambridge and Guelph. Most of these concerns remain and have been confirmed in joint studies performed by Hydro One and the distribution companies in the area.

Based on the demand forecast for this area, the supply deliverability assessment, the contingency assessment and the adequacy of the steady-state voltage levels of the existing transmission facilities are major concerns.

A number of plans have been initiated by Hydro One to address the immediate concerns identified in the study. To ensure the long-term supply to the area, a new 500/230 kV supply point and possibly a new 230/115 kV supply point will also be required.

Specifically, the supply to Kitchener and Guelph area loads provided via the 115 kV circuits D7G and D9G represents an immediate concern. The thermal overloads on circuit D7G can potentially occur under peak conditions for a contingency involving the loss of the companion circuit D9G. Post-contingency voltage declines over these circuits are also a concern. The joint study identified the need to add various low voltage shunt capacitors and also upgrade the thermal capacity of D7G and D9G circuits. The expected in-service date for the circuit upgrades is 2005-Q2. However, even with the upgrades, these circuits could run out of capacity by 2009. New transmission facilities, such as a 230/115 kV autotransformer at Preston TS, will be required unless new local resources are added.

Similarly, the thermal capacity to supply Guelph via the 115 kV circuits B5G and B6G and the Burlington 115 kV system is a concern. Hydro One is in the process of installing a 115 kV, 125 Mvar capacitor bank at Burlington Transformer Station. The expected in-service date of this project is before the summer of 2004. This capacitor bank will alleviate, in the near-term, the transfer capability concern of the Burlington 230/115 kV autotransformers identified in last year's 10-Year Outlook, and delay the need for additional transformation capability until the later part of the Outlook period. However, by 2007 thermal overloads on circuit B5G could occur under peak conditions for a contingency involving the loss of the companion circuit B6G. Installing low voltage reactive compensation equivalent at Hanlon TS and Cedar TS could delay the need for line upgrades of circuits B5G and B6G to about 2012.

Finally, for the Guelph area, Hydro One is developing a proposal to add a new customer connection point by 2005 to supply the projected load growth.

The Detweiler 230/115 kV transformation point could exceed its 10-Day LTR transfer capability on loss of an autotransformer. Hydro One has received approval to replace the Detweiler T3 autotransformer, one of the 230/115 kV autotransformers at Detweiler, with a slightly higher rated unit. The T3 is the lowest rated autotransformer at this location and its replacement will help to alleviate loading concerns at this transformation point under peak conditions.

Pre-contingency voltage levels at certain points in the Detweiler operating area are also a concern. Based on the projected demand for each selected year of study in the Outlook period, the 230 kV voltage is forecast to be weakest at Detweiler and Orangeville and to a lesser extent at Burlington. The Hydro One plan to install a 230 kV, 300 Mvar capacitor bank at Burlington before 2005 will help ensure adequate 230 kV voltage levels in this area. The 115 kV voltage levels at Detweiler and Burlington are also lower than typical operating levels and, at Brant TS and Cedar TS lower than the minimum market rule requirement of 113 kV. The installation of the 115 kV, 125 Mvar capacitor bank at Burlington in 2004 and the proposed installation of 20 Mvar capacitor bank at Cedar TS (which is partially supplied by Detweiler) in 2007 by Hydro One will provide additional support. In the absence of resource additions, more reactive sources will be required at or near Detweiler and at the low voltage side of the load transformer stations. Hydro One has a plan to install a 230 kV, 225 Mvar shunt capacitor at Detweiler by 2007.

Supply interruptions for load levels between 250 MW and 500 MW will occur in the area for certain 230 kV double circuit line contingencies (M20D+M21D, D6V+D7V and B22D+B23D) without the switching capability to restore the load back to service within 30 minutes. With certain loads approaching 500 MW, the installation of switching capability may not be sufficient. If load levels exceed 500 MW level, new transmission facilities may be required.

For the long-term, major transmission reinforcement is required to continue to provide supply capacity for a ten to fifteen year period beyond 2009. Hydro One is considering plans to upgrade the thermal capacity of 230 kV circuits M20D and M21D by 2009 and to construct a new 500/230 kV transmission supply point in the Detweiler area by 2011.

An alternative option for reinforcing the transmission network supplying the Detweiler area is a 500/230 kV supply point where the 500 kV circuits from Bruce NGS cross the 230 kV lines between Detweiler TS and Orangeville TS.

Supply Reliability from Stayner Transformer Station

In order to ensure supply reliability, a load rejection scheme at Stayner Transformer Station has been installed. This scheme is armed during cold weather conditions during the winter as much of the load in the area is related to the ski industry. As winter peak conditions were not explicitly studied for this Outlook, no potential concerns have been identified for this area. However, this situation requires monitoring to ensure that the customers in this area can continue to be supplied reliably.

Supply to Grey County

The contingency assessment of transmission circuits reveals the 115 kV S1H (Owen Sound-Hanover) circuit could become thermally overloaded for a 230 kV B4V and B5V double circuit contingency under summer peak conditions in 2010.

Lake Erie HVDC Interconnection Project

The proposal by Hydro One and TransEnergie US to construct a 990 HVDC interconnection, which would connect at the Nanticoke TGS and cross Lake Erie, has high project uncertainty. For this Outlook period, the IMO has not considered the impact of this interconnection in any of the transmission assessments.

4.7 West Zone

Impact of Shutdown of Lambton TGS

The shutdown of Lambton TGS by the end of 2007 would impact the operation of the IMO-controlled grid but to a lesser extent than the shutdown of Nanticoke TGS. Lambton TGS with its reactive power capability provides the voltage support needed to allow the current range of power transfers into and out of the West zone via the BLIP/NBLIP transmission interface. Without this reactive capability within the West zone, maximum power transfers on this interface could diminish. Reducing the maximum power transfers will also affect imports and exports from and to Michigan, respectively. Exports to Michigan could be limited. While imports from Michigan could improve the situation locally at Lambton, imports to load points east of the West Zone could also be limited. If replacement generation is not located in this zone, transmission reinforcement and additional reactive capability will likely be required to maintain current capabilities.

In addition, the shutdown of Lambton TGS will result in a lack of supply to the Scott operating area. The existing transmission infrastructure in this area is not adequate to provide the required power transfers to ensure reliable supply.

As detailed in the 'Need for Transmission System Reinforcement' section below, the proposed Hydro One concept of a new 500 kV circuit built between Lambton SS and Longwood TS would address these concerns.

Supply to Lambton & Middlesex Counties

The supply deliverability assessment shows a load pocket consisting of between 250 MW and 500 MW, located east of Scott TS and west of Buchanan TS, that would experience a supply interruption as a result of a double circuit line contingency. However, since one of these supply circuits is equipped with sectionalizing devices, it should be possible to restore some load within 30 minutes.

The thermal transfer capacity at the Scott and Buchanan 230/115 kV transformation points continues to be a concern. At Scott, for the loss of autotransformer T6, loading on the remaining autotransformer, T5, will exceed its 10-Day LTR. With the proposed Hydro One installation of a new Kent 230/115 kV autotransformer, some loads can be transferred from Wallaceburg TS to Kent to relieve the Scott autotransformers. At Buchanan, by 2010, the 230/115 kV transformation point may also become thermally overloaded based on the 10-Day LTR transfer rating for the loss of an autotransformer. Without any resource addition near the Buchanan transformation point, the addition and/or replacement of transmission facilities may be required to increase the transfer capability. Hydro One is considering the installation of shunt capacitors as early as of 2007 to relieve the Buchanan autotransformers.

Supply to the Windsor Operating Area

The completion of the ATCO-Brighton Beach Generating Station (GS) during the first half of this year will provide enhanced supply capability to the Windsor area. However, the IMO has concerns about possible constraints on the operation of this new generating facility and others during periods when high transfers are being made into Ontario from Michigan via the J5D Interconnection.

In particular, the limited rating of the two 230/115 kV autotransformers at Keith TS and the two 115 kV circuits, J3E and J4E, between Keith TS and Essex TS could impose restrictions on either the output of the generating facilities within the area or on the level of transfers into Ontario. The situation would become more acute whenever transmission facilities are unavailable.

Hydro One is currently developing proposals to address these problems.

The area is also especially vulnerable to the impact of double circuit contingencies. A double circuit contingency involving the 230 kV circuits C21J and C22J, between Keith TS and Chatham TS, would isolate Keith from the 230kV system, leaving only the interconnection with Michigan and the two connections to the 115 kV system. Similarly, a double circuit contingency involving the 230 kV circuits C23Z and C24Z, between Lauzon TS and Chatham TS, would isolate Lauzon TS from the 230 kV system, leaving it connected through to Keith TS via only the two 115 kV circuits to Essex TS.

The IMO therefore recommends that, in addition to the replacement of the autotransformers at Keith and the uprating of circuits J3E and J4E, consideration be given to establishing a new 230 kV connection between Keith TS and Lauzon TS. This would allow the ATCO-Brighton Beach GS to be used to provide reactive power support to the 230 kV buses at both Keith TS and Lauzon TS under contingency conditions. It would also allow all four circuits into Chatham to be used to accommodate the transfers into Ontario across the J5D Interconnection as well as any excess output (over the local load) from other generating facilities in the Windsor area.

A possible interim arrangement that is under consideration by Hydro One would involve constructing a 230 kV, 12 km section of double circuit line between Sandwich Junction and Lauzon TS and connecting it to the two 230 kV circuits C21J and C22J at Sandwich Junction. A new 230 kV bus would also need to be established at Lauzon TS with the termination to it of the new 230 kV circuit and the two existing 230 kV circuits C23Z and C24Z, as well as the two 230/115 kV autotransformers and the four transformers. Once this new connection is established it could eventually be extended the remaining 21.4 km into Keith TS to provide the recommended Keith TS to Lauzon TS link.

This interim arrangement involving a new 230 kV line between Sandwich Junction and Lauzon TS could also alleviate the current potential overloading of 230 kV circuit C24Z under contingency conditions.

The Kingsville area with the Windsor operating area remains a concern although the Hydro One proposed installation of a 230/115 kV autotransformer at Kent TS and the transfer of the Tilbury area load from Lauzon TS on to the new supply will have a major benefit. Furthermore, the installation of a new 230 kV connection between Keith TS and Lauzon TS would also provide benefits for this area by lessening the impact on the 115 kV bus voltage at Lauzon TS (from which this area is supplied) of single circuit contingencies involving either circuit C23Z or C24Z.

Need for Transmission System Reinforcement

The capability of the 230 kV transmission corridor between Lambton SS and Chatham TS may at times limit both imports into Ontario and internal generation dispatch within the Scott operating area. Without imports from Michigan, control actions must be in place under high ambient temperatures and windless conditions to avoid 230 kV circuit L28C from exceeding its continuous rating for the loss of 230 kV circuit L29C. The only effective control action is to limit generation in the Scott operating area. Increasing the transfer capability between Lambton and Chatham would alleviate this bottleneck. Replacing the 115 kV circuit N5K with a new 230 kV or 500 kV circuit between Lambton and Chatham is an option that would increase the transfer capability. However, it should be noted that dispatch of the new ATCO-Brighton Beach generating station is expected to reduce power flows on these circuits.

Since the Imperial Oil generating facility in the Scott operating area is intended to supply all of the load at the Imperial Oil complex, its completion during the first half this year will result in an equivalent increase in the transfers on the 230 kV system into London. These transfers become a concern during periods of high ambient temperatures and windless conditions if maximum power transfers are also being made into Ontario from Michigan, especially with respect to the flows on 230 kV circuits N21W and N22W from Scott TS to Buchanan TS.

If the generation-load balance in the West zone were to change significantly from its present state, the West zone would then require transmission reinforcement to increase its transfer capability within the zone and to other parts of province. The Hydro One proposed addition of a Lambton-Longwood 500 kV circuit and 70 percent series compensation of 500 kV circuit N582L would increase this transfer capability. If Lambton TGS is shutdown, this transmission reinforcement will ensure the reliable supply of the Scott operating area by increasing the transfer capability to it. If the generation capacity within the Scott local area was to significantly increase from its present level, this transmission reinforcement could alleviate the possibility of congestion. However, several generation projects currently in the CAA queue have withdrawn their connection application. Therefore, the overall forecast for congestion in the West zone is low. It should be noted that the 500 kV circuit between Lambton and Longwood would also alleviate those periods of concern regarding Imperial Oil and increased power transfers on the 230 kV system into the London area.

4.8 Ottawa Zone

Supply to eastern half of the City of Ottawa plus smaller loads along the Ottawa River up to Hawkesbury

Based on the demand forecast for the Ottawa area, the Hawthorne 230/115 kV transformation point could exceed its 10-Day LTR transfer capability on loss of autotransformer T4. To relieve this concern, Hydro One is installing a new 250 MVA, 230/115 kV autotransformer at Hawthorne to increase the transfer capability. The expected in-service date of the new autotransformer is before the summer of 2004.

The thermal capacity of the 115 kV circuits out of Hawthorne TS is also a concern under summer peak conditions. In particular, a single contingency involving 115 kV circuit A4K or H2AR could result in the overloading of some of the remaining 115 kV circuits. To alleviate these concerns and in conjunction with installation of the new autotransformer, Hydro One is adding two more 115 kV circuits between Hawthorne TS and Blackburn Junction, stringing a second circuit between Blackburn Junction and Russell TS, and reconfiguring some existing 115 kV circuits. This work is also expected to be completed before the summer of 2004. These reinforcements will result in a new double circuit line from Hawthorne TS supplying Russell TS and the existing 115 kV circuit H2AR becoming a dedicated supply for loads east of Ottawa.

Hydro One has also recently completed the thermal upgrading of one section of 115 kV circuit H9A, from Gamble Junction to Bilberry Creek TS. This work will improve the supply reliability to Bilberry Creek TS by eliminating the possible overloading of H9A during peak conditions. However, with certain outage and operating configurations during peak demand conditions, the 115 kV voltages could be lower than the minimum market requirement of 113 kV. Low voltage capacitors will also need to be installed at stations supplied from H9A to meet the Market Rules requirements for minimum system voltages.

In addition, only the Bilberry Creek portion of load on 115 kV circuit H9A can be readily transferred to another Ontario supply via 115 kV circuit H2AR. The rest of the H9A load could be supplied only if a supply from Quebec is available.

Quebec HVDC interconnection Project

The proposal by Hydro One to build a 1,250 MW HVDC interconnection with Quebec has high project uncertainty. For this Outlook period, the IMO has not considered the impact of this interconnection in any of the transmission assessments.

4.9 Northeast and Northwest Zones

4.9.1 Northeast and Northwest Zones

Improving the Transfer Capability of the East-West Tie Interface

As shown in Figure 4.1, the East-West Tie interface connects the Northeast zone to the Northwest zone. Historically this interface has limited power flows between the zones at the expense of constraining generation on and off. Recently, Hydro One has upgraded the reactive compensation facilities at Wawa TS by replacing the existing four shunt reactors with two new 40 Mvar units and by installing shunt capacitors with a total reactive capability of 80 Mvar. An increase of about 30 MW in power transfer capability on the East-West interface could be achieved under certain system conditions. However, any expansion of the East-West interface limits requires coordination with Manitoba and Minnesota to avoid adversely affecting their operations. Detailed operating studies need to be completed to establish the new system security limits and system operating instructions associated with the new reactive compensation facilities added at Wawa TS.

Impact of a new High Capacity Ontario-Manitoba Interconnection

Manitoba Hydro and Hydro One are participating in a feasibility study to explore a high capacity interconnection to permit a potential purchase of up to 1,500 MW from Manitoba. The earliest in-service date is 2011. Three main transmission alternatives are under consideration:

DC to Sudbury: A DC line directly connected from northern Manitoba to Sudbury. This option involves the shortest transmission line, results in the lowest losses, but doesn't improve service to northwestern Ontario.

DC to Thunder Bay: A DC line directly connected from northern Manitoba to Thunder Bay, and then a new AC line from Thunder Bay to Sudbury. This option would have potential service benefits for northwestern Ontario, but introduces higher losses.

AC with back-to-back DC: A DC line from northern Manitoba to Winnipeg and an AC line from Winnipeg to Sudbury. This option would have potential service benefits for northwestern Ontario, but introduces higher losses.

In order to accommodate a power injection of 1,500 MW into Northern Ontario area it will be necessary to improve the power transfer capability of various transmission interfaces and install additional facilities to mitigate the impact on reliability:

A. The reinforcement of the 500 kV interface between Hanmer TS and Essa TS should accommodate a continuous power flow of about 3,200 MW, an increase of 1,800 MW.

Hydro One studies indicate that series capacitors would provide most of the required capacity increase.

B. The reinforcement of the 500 kV corridor between Essa TS and Claireville TS should accommodate a continuous power flow of about 1,700 MW, up from 1,000 MW. Specific transmission reinforcements are yet to be determined.

C. Additional reactive compensation devices are likely to be required, in order to maintain an acceptable voltage profile along the transmission system.

D. A contingency based Special Protection Scheme would be required to trigger the HVDC run-back in case of a contingency associated with the critical transmission elements.

One of the important aspects of major interconnection projects is the effect that the project might have on the neighbouring interconnected utilities. Upon completion of more detailed planning studies it is possible that facilities and/or measures in addition to those listed above could be identified as required in order to meet the NPCC basic criteria for interconnected power system design.

4.9.2 Northeast Zone

Impact of Great Lakes Power Transmission Reinforcement

The Great Lakes Power Limited transmission system between Anjigami TS and Mississagi TS in the Northeast zone, provides supply to a peak load of about 380 MW. The GLP transmission also provides corridors for peak generation of about 470 MW. Great Lakes Power Limited - Transmission Division (GLPL) has received approval from the IMO to pursue plans to reinforce the transmission system between Anjigami TS and Third Line TS and between Third Line TS and Mississagi TS. The transmission reinforcement will alleviate present transmission system limitations and provide improved reliability of supply and connectivity. The project is expected to be completed by the end of 2006. The preferred transmission reinforcement option comprises:

- One new 230 kV circuit from Wawa TS to MacKay TS to Third Line TS, that will be connected to MacKay TS via a new 115/230 kV autotransformer,
- The installation of one additional 230 kV breaker at Wawa TS,
- The upgrading of No.3 Sault 115 kV circuit to 90 MVA,
- The building of a 230 kV switchyard at Third Line TS including a ring bus of four 230 kV breakers to connect the new 230 kV circuit, the existing 230 kV circuits P21G and P22G, and the two existing 230/115 kV autotransformers,
- The removal of four 115 kV circuits; No.1 Anjigami, No.2 Anjigami, No.1 Sault, and No.2 Sault,
- The replacement of under-rated breakers at all transformer stations, and
- The retermination of some of the existing circuits connecting to MacKay TS and No.3 Sault 115 kV switchyards.

The GLPL proposed transmission reinforcement represents an enhancement to the Northeast transmission system. It will improve the reliability of the IMO-controlled grid and would bring increased efficiencies to the electricity market. Some of the benefits are:

A. The reduction or elimination of the bottling of the Michipicoten River hydraulic plants (connected to Anjigami TS) due to transmission restrictions, thereby resulting in a decrease in Congestion Management Settlement Credits (CMSC) payments.

B. The GLPL inflow limit will be enhanced and substantially reduce the dependence on the special protection systems (SPSs) that are presently employed in the area. Due to the weakness of the existing transmission system in this area, the operation of the system relies extensively on special protection systems, including load and generation rejection schemes:

   - Up to 100 MW of load is armed for rejection continuously at Third Line, to prevent the collapse of the GLPL system in post-contingency when the GLPL internal load is supplied mainly via the Mississagi TS and Wawa TS transformers.
   - Wells GS and Lake Superior Power are armed for rejection under high Mississagi Flow East conditions and storm weather in order to provide improvement to the east flow power transfer limit.
   - A relay is installed at Wawa TS to detect high post-contingency power flows on the 230/115 kV autotransformers. The operation of the relay will separate the GLPL system from the Hydro One system.
   - A cross-tripping scheme is in service which, in the event of a double circuit contingency involving P25/26W will disconnect the autotransformers T1 and T2 at Wawa TS, thus again isolating the GLPL transmission system from the Hydro One transmission system at Wawa.

   With the addition of the proposed transmission some of these special protection systems may not be necessary or could be used to further enhance system operating limits. The IMO will establish the usefulness of these SPSs as part of future system limits studies.

C. The proposed transmission reinforcement is likely to provide increased voltage support at Wawa TS, resulting in an improvement in the voltage stability for the area. This may possibly result in an increased in the power transfer limit over the EWT interface for certain conditions of power flows over the Northwest zone interconnections with the neighbouring utilities.

D. For conditions of high flow east on the Mississagi East interface an improvement of about 50 MW in the east transfer limit may be achieved and the need to reject Wells GS and Lake Superior Power GS generation in post-contingency could be reduced or eliminated. This would considerably reduce the bottling of generation west of Mississagi, during high flows eastbound and storm conditions.

E. This transmission development and, in particular, the proposed configuration of the 230 kV MacKay TS and Third Line TS will allow for future transmission system expansions and possible incorporation of generation projects.

Need for Transmission System Reinforcement

Presently, double element contingencies that result in thermal overloads on transmission circuits in the Northeast zone are not recognized in the day-to-day normal operations of this zone. Consequently, overloads due to double element contingencies have not been evaluated for the Northeast. However, in general, double element contingencies on the Northeast 230 kV system result in overloads on the 115 kV Northeast system. If double element contingencies were to be recognized, immediate transmission reinforcements would be required.

The loss of 500 kV circuit P502X leaves most of the Northeast with only one 115 kV connection to the rest of the Ontario transmission system. To secure the operation of this zone, an SPS enforces a load-generation balance following the loss of P502X. In practice, generation rejection is armed most days and load rejection is armed most nights. Given that the operation of the Northeast zone relies so heavily upon an SPS for a single element contingency, the existing transmission infrastructure provides a relatively lower level of reliability compared to the rest of the IMO-controlled grid. Reliability could be improved with transmission reinforcements on the 115 kV system between Ansonville and Dymond. The SPS is complicated and generation rejection at many different sites has to be very well coordinated. As a result, the SPS has not always been able to produce the desired outcome.

In addition, a contingency involving 500 kV circuits P502X or D501P without generation rejection would cause many thermal overloads on the remaining 115 kV circuits. The use of generation rejection to prevent thermal overloads for a single contingency suggests that transmission reinforcements in the Northeast zone are needed.

The proposed high capacity transmission link between Manitoba and northern Ontario could alleviate concerns involving circuit P502X. Under option two and three, a second 500 kV line would be constructed between Porcupine TS and Hanmer TS. With the new transmission line in service, the reliance on the SPS would decrease, the possibility of thermal overloads would decrease, and system reliability would improve considerably.

4.9.3 Northwest Zone

Impact of Shutdown of Atikokan and Thunder Bay TGS

The shutdown of Atikokan and Thunder Bay TGSs by the end of 2007 would leave the Northwest zone deficient in generation unless replacement generation is located in this zone. Depending on the location of any replacement generation, more special protection systems utilizing load rejection could be required. In the absence of any replacement generation, imports from Manitoba and Minnesota and power transfers from the Northwest via the East-West Transfer West (EWTW) transmission interface could be utilized to supply loads in the Northwest zone. However, the supply capability from these sources could be limited by available water levels for hydroelectric generation and new transmission constraints resulting from the shutdowns.

In particular, the shutdown of Thunder Bay TGS would create an immediate supply shortage of approximately 150 MW for the City of Thunder Bay and surrounding areas. Replacement generation at Thunder Bay TGS would be required to alleviate this concern. In the absence of any replacement generation, transmission reinforcements to this area would be required. The construction of 230 kV transmission from Lakehead TS to Birch TS is a possible transmission solution for this supply concern.

Historically, Thunder Bay TGS with its reactive power capability, from generating and condensing units, has also provided voltage support for the local loads at and near the City of Thunder Bay. When neither generating unit was on line, arrangements were made to ensure the condensing unit was dispatched to support voltages but at an additional cost. Recently however, with the addition of an 80 Mvar shunt capacitor at Birch TS, the need for the Thunder Bay generating and condensing units to maintain voltage levels has reduced. Although the condensing unit now provides redundant voltage support, its use could be required in the event that the Birch shunt capacitor becomes unavailable. With no reactive power from Birch TS or Thunder Bay TGS, load shedding could be required to maintain voltage levels in this area under certain demand conditions. The shutdown of Thunder Bay TGS would result in the need for additional sources of active and reactive power.

The Northwest transmission system comprises only one 1,000 km double circuit 230 kV line with a 115 kV underlay. Only one generating station, Atikokan TGS, is directly connected to the 230 kV system. The shutdown of Atikokan TGS with its reactive power capability will limit the ability of the ETWE interface to transfer imports from Minnesota to load points east of this interface. Without Atikokan TGS, the East-West Transfer East (EWTE) interface limit could reduce by fifty percent. If replacement generation is not located at or near MacKenzie TS, additional reactive compensation would be required. Transmission reinforcement on the EWTE interface would also improve the transfer capability.

In the absence of any replacement generation, or equivalent demand-side measures, for the shutdown of Atikokan TGS and Thunder Bay TGS, the 230 kV East-West tie would require upgrading to allow for up to 400 MW east (EWTE) and 440 MW west (EWTW) to address the above congestion and resource adequacy concerns.

Need for Transmission System Reinforcement

Like the Northeast zone, but to a lesser extent, the use of special protection systems is also required for the operation of this zone. Even at a relatively large station like Rabbit Lake TS a relatively small new load was required to participate in a load rejection scheme in order to avoid adversely affecting nearby consumers.

Several customers in this zone have indicated that the existing Market Rules regarding minimum voltage will not meet their requirements. Some customers lack the under load tap changing (ULTC) transformers that would allow them to compensate for changes in the 230 kV and 115 kV transmission system voltages. Higher than minimum voltages can be maintained at additional cost by constraining the output of specific generation or other rotating reactive resources.

For contingencies involving the Lakehead-Marathon 230 kV circuits, post-contingency overloads could occur on the parallel Lakehead-Alexander-Marathon 115 kV circuits. During times when these overloads may occur on the 115 kV circuits, control actions are implemented to constrain generation off in the Northwest zone in order to reduce the west to east transfers on these circuits.

In the late 1990s, a contingency in the Mid-Continent Area Power Pool (MAPP) region resulted in the collapse of the Northwest power system. As a result, the Northwest system operation criteria have been reviewed. In the short term, the IMO is working towards implementing the System Operating Limits that will reduce the adverse exposure of the MAPP system to the possible contingencies in Ontario. In the long-term, an upgrade to the Northwest transmission system will be required to satisfy the normal NPCC and MAPP operating standards. At this time, no date has been identified for this upgrade.

Long-term Supply Reliability of the Northwest Zone

In the long-term, the proposed high capacity transmission link between Manitoba and Northern Ontario could also provide much needed supply capacity for the Northwest zone. Under two of the three options, the new transmission would connect to a point in the Thunder Bay area. These interconnection alternatives provide a high-capacity link between the Northwestern Ontario and the rest of the system. Construction of either of these options would significantly enhance the reliability of supply to loads in Northwestern Ontario and would effectively eliminate any northwestern Ontario supply adequacy concerns.

4.10 Niagara Zone

Need for Transmission System Reinforcement

The Queenston Flow West (QFW) interface, between the Niagara and Southwest zones, has been limiting under hot windless conditions. Without expanding the thermal capability of QFW, adding generation in the Niagara zone does not increase generation availability as the import capability from New York is correspondingly reduced.

Hydro One is proposing to install new transmission facilities to augment the five existing 230 kV circuits that, together, form the QFW Interface.

The facilities that are planned to be installed consist of two new 230 kV circuits between Allanburg TS and Middleport TS. In addition it is planned to reconfigure the three existing 230 kV transformer feeders Q26A, Q28A and Q32A between Beck 2 GS and Allanburg TS. This will then create two new 230 kV connections between Beck 2 GS and Middleport TS.

The planned in-service date for the new facilities is May 2007.

These new facilities are expected to increase the transfer capability of the QFW interface by approximately 800 MW. However, without reinforcing the 230 kV transmission facilities into Burlington TS, the full benefit in upgrading the QFW interface may not be realized. In the past, under peak summer conditions, these 230 kV transmission facilities have constrained power flows on the QFW interface.

Need to Improve Market Efficiency

The Market Surveillance Panel's (MSP's) report of July 3, 2003, titled *Constrained Off Payments and other Issues in the Management of Congestion*, identified several issues associated with the Niagara 25 Hz System. The generation and transmission required to reliably supply the 25 Hz load is out of proportion compared to the 60 Hz system. The 25 Hz generation capacity significantly exceeds the 25 Hz demand by approximately more than 3 to 1. Due to the limited transfer capability of the Beck 60/25 Hz frequency changer, a significant amount of 25 Hz generation is constrained off. In addition, at times, the 25 Hz load at Gage Transformer Station pulsates creating frequency excursions. To manage these frequency excursions, more than one Beck 1 unit is required in-service resulting in generation that is constrained on.

A Niagara 25 Hz Working Group, which included all the Canadian 25 Hz facility owners under the leadership of the IMO, has recently made recommendations to the IMO Board to deal with the issues identified in the MSP's report. Further analysis and stakeholdering of the preferred alternative is required before proceeding.

Supply Reliability to the Allanburg Operating Area

IMO assessments regarding new supply points in the Allanburg operating area indicate that power flows into the 115 kV operating area and over the internal 115 kV transmission interfaces are closely dependent on the Decew Falls GS and Beck 1 GS generation dispatch in the operating area.

Under peak load conditions and certain internal generation patterns, the IMO has identified some supply reliability concerns. Specifically, the existing 115 kV circuits D10S, D9HS, Q11S and Q12S between Decew Falls GS and Beck 1 GS could become thermally overloaded over their 15-Minute Limited Time Ratings for a contingency associated with a section of the companion circuit. The Allanburg autotransformer T1 could become overloaded in pre-contingency situations for high power flows on Q30M to Middleport or after a contingency with the double circuit 230 kV line Q30M and Q32A or the Beck 1 E bus. In addition, the voltage decline at Crowland TS could exceed 10% for the loss of the double circuit 230 kV line Q26A and Q28A.

The planned transfer of Norfolk TS, about 85 MW of load, to Caledonia TS before the summer of 2004 by Hydro One, and the capping of the Beamsville TS and Vineland DS loads to the stations' capabilities appear to relieve the loading on the Allanburg autotransformers for the next six to seven years. As the load continues to grow however, it may be necessary that additional transmission or generation will be required to address concerns related to Allanburg TS, especially the rating of autotransformer T1.

4.11 East Zone

Supply to Dobbin Operating Area

Low pre-contingency 115 kV voltage levels remain a concern at or near the Dobbin Transformer Station based on the demand forecast and study assumptions starting in 2010. This voltage could be improved by providing additional 230 kV supply points to Dobbin. Tapping the 230 kV circuits from Cherrywood TS that by-pass Dobbin is an option.

Need for Transmission System Reinforcement

The frequent use of load rejection schemes at Dobbin, Sidney, Port Hope and Frontenac Transformer Stations to respect single element contingencies with all elements in-service suggests that transmission reinforcements at or near these stations are required.

4.12 Essa Zone

Supply to Muskoka District Municipality and part of Simcoe County

The supply deliverability assessment indicates that consumers to the east of Essa and west of Minden could be subject to interruptions outside the IMO guidelines. These consumers are supplied by a 230 kV double circuit line and have an aggregated load level between 250 MW and 500 MW. For a contingency involving the double circuit line, a supply interruption to these consumers occurs with no means of sectionalizing to restore the load back to service within 30 minutes of the event.

Supply to Barrie Area, Simcoe County

The supply reliability to the Barrie area could potentially become problematic. Under summer peak conditions for each selected year of study, the Essa 230 kV T1 autotransformer could become thermally overloaded above its 10-Day LTR transfer capability for loss of Essa 230 kV T2 and vice versa. In the absence of resource additions to the local 115 kV system, transmission reinforcements would be required to alleviate this concern.

4.13 Bruce Zone

The transmission adequacy assessments did not reveal any potential concerns for this zone for the current six unit configuration at Bruce NGS.

4.14 Congestion Assessment

Transmission flows are determined by the pattern of loads and generation, and the characteristics of the transmission system at any given time. Each of these factors is inherently unpredictable due to the effect of random forced outages on generation and transmission facilities and the effect of weather on load levels. If additional generation is added to appropriate points on the system in future years, the level of system flows on constrained interfaces would generally be expected to reduce and congestion would tend to be relieved. Conversely, if too much generation is added to a transmission zone, it could increase the level of system flows on the connecting transmission transfer interface, thereby creating or aggravating congestion. In these instances the incorporation of additional transmission capacity on the interface might be necessary to alleviate this problem.

4.14.1 MAPS Congestion Assessment

The MAPS software program was used to assess the potential duration and range of transmission congestion on Ontario’s major internal interfaces, under an economic generator dispatch pattern based on forecast operational costs and an interconnected pool system. With an economic dispatch of generation and respecting transmission constraints, the program may even dispatch resources external to Ontario to supply demand in Ontario, if it is more economic to do so, before dispatching internal resources within Ontario. Further details on the MAPS software program are identified in the IMO document titled “Methodology to Perform Long Term Assessments” (IMO_REP_0044). Details on Ontario’s major internal interfaces and associated limits can be found in the IMO document titled “Ontario Transmission System” (IMO_REP_0045).

The program allows for a projection of expected hours of congestion on an interface when the flow on that interface is constrained by a limit. To access the potential range, in MW, of the transmission congestion on the same interface, the program was re-run with the limit on the interface removed. The resulting maximum flow on the interface was compared with the interface limit to identify the potential range of congestion.

Table 4.2 summarizes the potential hours at the identified interface limit and the potential range of congestion based on the Existing Transmission Network Scenario and the following resource assumptions:

- Lakeview units removed from service beginning May 1, 2005,

- coal-fired generation at Nanticoke, Lambton, Atikokan and Thunder Bay is replaced by an equivalent amount of generation at those locations beginning January 1, 2008,
- Bruce A Unit 3 is removed from service beginning January 1, 2009,
- only five Pickering A Units are available for service, and
- generation resources listed in Table 2.2, for which the connection applicant has indicated that construction is in progress or has been completed are available for service.

The Planned Transmission Network Scenario was not studied because the additional transmission facilities considered in this scenario are not expected to significantly change the congestion results.

For the years and scenario conditions studied in this assessment, congestion is likely to occur on the East-West Transfer East (EWTE), East-West Transfer West (EWTW) and Flow South (FS) interfaces, and to a lesser extent the Queenston Flow West (QFW) and Negative Buchanan Longwood Input (NBLIP) interfaces.

The assessment shows the EWTE interface at times constrains off generation in the Northwest zone that would otherwise flow to load points in southern Ontario. Typically, this interface is constraining during low demand conditions where generating units in southern Ontario are unavailable. This results in a higher but limited dispatch of the Atikokan and Thunder Bay generating units. However, at higher demand conditions, the EWTW and FS interfaces frequently constrain off lower cost generation in the Northeast zone that would otherwise flow to load points in the Northwest zone and south Ontario. By 2010, due to a relatively flat demand growth rate in north Ontario and an increasing demand growth rate in southern Ontario from 2005 onward, more power is needed to supply loads in south Ontario. Consequently, more of the lower cost generation in the Northeast zone flows on the FS interface to southern Ontario. Since more power is required to flow to the south, less power flows into the Northwest zone via the EWTW interface and a corresponding higher dispatch of the Atikokan and Thunder Bay units is required for Northwest demand requirements, thus congestion reduces. In 2010, the QFW and NBLIP interfaces, to a limited extent, also constrain off generation to load points west and east of the QFW and NBLIP interfaces, respectively.

Table 4.2 Potential Congestion on Major Interfaces

Hours	2005	2010
EWTE	165	370
EWTW	1235	535
FS	605	1015
QFW summer	n/a	85
NBLIP	n/a	70

MW	2005	2010
EWTE	up to 135	up to 205
EWTW	up to 240	up to 200
FS	up to 435	up to 475
QFW summer	n/a	up to 645
NBLIP	n/a	up to 445

The potential range of congestion on these interfaces could be higher than indicated in the studies for a number of reasons. During circuit outage conditions or under extreme weather, congestion can be aggravated above the levels modeled by the IMO. Congestion also occurs on the QFW and NBLIP interfaces during periods of high demand or tight supply, when imports from New York, over the Niagara interconnection, and from Michigan are required.

-End of Section -

This page intentionally left blank.

5.0 Overall Observations, Findings and Conclusions

- Additional Ontario electricity supply and demand-side measures are required to maintain supply adequacy into the future and to reduce Ontario's dependency on supply from other jurisdictions. The reactivation of 2,000 MW of nuclear capability over the last 12 months and the addition of 755 MW of gas-fired generation expected by this summer have eased some of the near-term concerns. However, more resources are required in every year of the Outlook period, some with a high degree of urgency.
- By 2014, up to 11,600 MW of Ontario's electricity requirement will need to be met with new supply, refurbished generation or demand-side measures. Of this amount, up to 5,400 MW is associated with economic demand growth and other known generation retirements, with the remainder required to replace existing coal-fired generation in the province.
- Some of the new generation, built to meet supply requirements, should be situated close to or within Toronto. Lakeview generation can be replaced by generation in the GTA, east of Milton. All the proposed new generation projects for the Toronto zone meet this local requirement, and their timely completion would bring benefit to the overall reliability of the Ontario power system and would alleviate supply concerns in downtown Toronto and the western GTA. These projects will complement, but not replace, the need for transmission reinforcements. The coal-fired generation retirement program will require that an equivalent amount of capacity is located in the same electrical zone as the station being shutdown, in order to avoid transmission adequacy and system operability issues.
- Demand-side initiatives should be vigorously pursued in Ontario, as clean and less expensive ways to reduce the supply requirement. The application of conservation measures is virtually unrestricted with respect to location.
- The increasing age of Ontario generation was identified in last year's Outlook as a potential issue toward the end of the study period and beyond, as much of the existing generation infrastructure reaches or exceeds its nominal life. Other than coal shutdown, the possible shutdown of Bruce Unit 3 in 2009 is considered (subject to any future refurbishment decision which may be taken by Bruce Power), as well as the need for re-tubing of the Pickering B Units 5, 6 and 7, by the end of 2013 (pending development of refurbishment plans by OPG).
- Several transmission infrastructure additions in the GTA are required to be completed before summer 2005 peak conditions to coincide with the shutdown of Lakeview TGS to prevent overloading of autotransformers and to provide adequate reactive power capability to maintain acceptable voltages. These transmission additions include the initial phase of Parkway TS with the installation of the first autotransformer and the installation of shunt capacitors banks at Burlington TS, Richview TS and John TS.
- Options for either the installation of a shunt capacitor bank at Trafalgar TS plus restrictions on automatic low voltage control or the conversion of two generation units to synchronous condenser operation at Lakeview TGS are being pursued to provide sufficient reactive power under extreme loads and/or outage conditions.

- The development of Parkway TS will improve the supply reliability for loads in Vaughan, Richmond Hill and Markham and reduce 500/230 kV autotransformer overloads.
- Further reinforcement, either transmission or generation, will be required to improve the supply capability to the combined Southwest and Toronto zones as early as the summer of 2006 under extreme load conditions and certain generator outages. Local reinforcement to improve the supply capability to the western portion of the GTA will be required as early as the summer of 2006 under extreme load conditions.
- Transmission reinforcement is required in order to maintain the reliability of supply to northern Mississauga, Brampton, Milton, the Town of Halton Hills, Vaughan and northern Toronto. These municipalities are susceptible to supply interruption for a double circuit line contingency.
- The new 230 kV bus and associated switching arrangement at Cooksville TS proposed by Hydro One will improve the supply reliability for loads in southern Mississauga and southern Oakville. However, there will continue to be some loads that will be vulnerable to supply interruption for a double circuit contingency.
- Plans are in place to improve the supply to downtown Toronto. The initial stage of establishing a new link between John TS and Esplanade TS will improve the transfer capability between the Leaside and Manby sectors. Hydro One has indicated that the earliest in-service date for this link is 2008. Hydro One has proposed two alternatives for the remaining work to complete the third supply into Toronto. The first stage is expected to be completed by 2010, while the second phase would not be completed until around 2020. The IMO has found both options to be acceptable from a system reliability perspective. However the IMO favours the DC option since fewer system upgrades are required.
- The Detweiler operating area, encompassing Kitchener-Waterloo, Cambridge and Guelph in southwestern Ontario, is susceptible to supply interruptions for double circuit line contingencies. Thermal overloads on the autotransformers in this area are also possible. Respecting minimum voltage levels is a third concern. A number of plans have been initiated by Hydro One to address the immediate concerns. Additionally, upgrades to the thermal capacity of transmission lines, a new 500/230 kV supply point and possibly a new 230/115 kV supply point eventually would be required to ensure the long-term supply to this area.
- There is a load pocket greater than 250 MW in the West zone that is susceptible to a supply interruption following a double circuit line contingency. This suggests that transmission reinforcement is needed in this area.
- The expected addition of the ATCO-Brighton Beach Generating Station will provide enhanced supply capability to the Windsor operating area. However, the IMO is concerned with the possible transmission constraints on the operation of generating facilities when imports are being made into Ontario from Michigan. Hydro One has developed plans to address these constraints. In addition, this area is highly vulnerable to the impact of 230 kV double circuit line contingencies. The IMO recommends that Hydro One develop proposals for reinforcing the 230 kV transmission network in this area.

- In the West zone, the 230 kV transmission corridor between Lambton and Chatham and the 230 kV corridor transmission between Scott and Buchanan could, under certain operating and weather conditions, bottleneck both imports and the internal dispatch of generation. Furthermore, if the generation-load balance in the West zone were to change significantly from its present state, the frequency of these bottlenecks would increase. Transmission reinforcement would be required to increase the transfer capability within the zone and to other parts of the province. Hydro One has identified transmission solutions to alleviate these concerns.
- The reliable supply to the City of Ottawa and surrounding areas will be enhanced with the current transmission projects being completed by Hydro One. However, near Bilberry Creek, concerns will still remain regarding minimum 115 kV voltages and operating flexibility to supply loads. Hydro One has identified transmission solutions to alleviate these concerns
- Potential thermal overload concerns have been identified following certain contingencies for several transformation points, and on a number of circuits in the Essa, Niagara, Southwest, Toronto and West zones. In addition, the potential for pre-contingency voltage levels to be below minimum requirements has also been identified, particularly in the Detweiler operating area.
- Existing congestion is likely to continue on the East-West Tie transmission interface. To allow higher volume transactions with Manitoba and Minnesota and to increase the transfer capability between the Northwest and Northeast zones, transmission enhancements are needed near Wawa TS or Marathon TS. The Wawa reactors/capacitors recently installed by Hydro One could increase the interface limit by about 30 MW under certain system conditions pending the outcome of detailed operating studies.
- Post-contingency overloads can also occur on the parallel Lakehead-Alexander-Marathon 115 kV circuits. During times when these overloads may occur, it is necessary to limit generation in the Northwest zone in order to reduce the west to east transfers on these circuits. Transmission reinforcements in this area would decrease congestion.
- In the Northeast zone, the proposed transmission reinforcement by Great Lakes Power Limited represents an enhancement to the Northeast transmission system. It will result in an improvement in the reliability of the IMO-controlled grid and would bring increased efficiencies to the electricity market.
- The continued use of a special protection system in the Northeast zone for 500 kV single element contingencies indicates the existing transmission infrastructure provides a relatively lower level of reliability compared to the rest of the IMO-controlled grid. This suggests that transmission reinforcement is required in this zone. Some options associated with the proposed high capacity transmission link between Manitoba and northern Ontario could alleviate some of these concerns.
- Some options associated with the proposed high capacity transmission link between Manitoba and northern Ontario could also enhance the reliability of supply to loads in the Northwest zone and could eliminate any Northwest supply adequacy concerns.
- Congestion on the Queenston Flow West (QFW) interface may also occur under hot windless conditions when imports from New York over the Niagara interconnection are required to

supply demand under certain generation dispatch and outage conditions. The proposed Queenston Flow West (QFW) interface reinforcements by Hydro One will increase the transfer capability of the interface and will help alleviate congestion. However, the full increased transfer capability of the QFW interface might not be realized if certain 230 kV transmission facilities in the Southwest zone are not also reinforced. The third supply DC option to downtown Toronto would also help relieve the QFW interface.

- At Niagara, the 25 Hz generation capacity significantly exceeds the 25 Hz demand. Due to the limited transfer capability of the Beck 60/25 Hz frequency changer and specific load characteristics, significant congestion payments have been by the IMO. Recommendations to the IMO Board have recently been made to deal with these issues.
- In the near term, the projects currently being completed by Hydro One in the Allanburg operating area will relieve loading on the Allanburg autotransformers for next six to eight years. However, as the load in this area continues to grow, additional transmission or generation will be required to address loading concerns at Allanburg, especially the rating of autotransformer T1.
- The frequent use of load rejection schemes in the East zone suggests that transmission reinforcements are required.
- Congestion on the Flow South interface is forecast to increase over the Outlook period. Hydro One is developing a proposal for increasing the transfer capability of this interface.

-End of Section -

Appendix A – Resource Adequacy Assessment Details

Table of Contents

List of Tables

1.0 Resource Adequacy Assessment Tables

The following tables provide numeric results of the resource adequacy assessment. They support Figure 3.1 in Section 3.2 and the statements made in Section 3.2, 3.3 and 3.4. Orange (darker for black and white display/print) cell shading in the 'Reserve Above Requirement' column means the forecast supply deficiency exceeds the current Ontario coincident import capability of 4,000 MW.

Table A1 Reserve Above Requirement Values Under Low Demand Growth, Annual Peak, Reference Resource Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Above Requirement MW
2005	23,544	17-Jul-05	27,910	27,094	4,366	3,550	18.5	15.1	816
2006	23,817	16-Jul-06	28,289	27,229	4,472	3,412	18.8	14.3	1,060
2007	24,041	15-Jul-07	28,241	27,350	4,200	3,309	17.5	13.8	891
2008	24,265	13-Jul-08	22,502	27,736	-1,763	3,471	-7.3	14.3	-5,234
2009	24,474	12-Jul-09	21,755	28,052	-2,719	3,578	-11.1	14.6	-6,297
2010	24,702	18-Jul-10	22,002	28,307	-2,700	3,605	-10.9	14.6	-6,305
2011	24,907	17-Jul-11	21,996	28,550	-2,911	3,643	-11.7	14.6	-6,554
2012	25,090	15-Jul-12	21,993	28,755	-3,097	3,665	-12.3	14.6	-6,762
2013	25,259	14-Jul-13	21,988	28,957	-3,271	3,698	-12.9	14.6	-6,969
2014	25,424	13-Jul-14	20,442	29,283	-4,982	3,859	-19.6	15.2	-8,841

Table A2 Reserve Above Requirement Values Under Median Demand Growth, Annual Peak, Reference Resource Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Above Requirement MW
2005	24,147	17-Jul-05	27,910	27,697	3,763	3,550	15.6	14.7	213
2006	24,446	16-Jul-06	28,276	27,861	3,830	3,415	15.7	14.0	415
2007	24,735	15-Jul-07	28,226	28,044	3,491	3,309	14.1	13.4	182
2008	25,027	13-Jul-08	22,486	28,630	-2,541	3,603	-10.2	14.4	-6,144
2009	25,305	12-Jul-09	21,738	29,033	-3,567	3,728	-14.1	14.7	-7,295
2010	25,605	18-Jul-10	21,984	29,368	-3,621	3,763	-14.1	14.7	-7,384
2011	25,883	17-Jul-11	21,977	29,694	-3,906	3,811	-15.1	14.7	-7,717
2012	26,139	15-Jul-12	21,972	29,985	-4,167	3,846	-15.9	14.7	-8,013
2013	26,384	14-Jul-13	21,965	30,266	-4,419	3,882	-16.7	14.7	-8,301
2014	26,611	13-Jul-14	20,419	30,653	-6,192	4,042	-23.3	15.2	-10,234

Table A3 Reserve Above Requirement Values Under High Demand Growth, Annual Peak, Reference Resource Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Above Requirement MW
2005	24,450	17-Jul-05	27,910	28,000	3,460	3,550	14.2	14.5	-90
2006	24,895	16-Jul-06	28,271	28,371	3,376	3,476	13.6	14.0	-100
2007	25,290	15-Jul-07	28,219	28,684	2,929	3,394	11.6	13.4	-465
2008	25,664	13-Jul-08	22,479	29,373	-3,185	3,709	-12.4	14.5	-6,894
2009	26,021	12-Jul-09	21,729	29,866	-4,292	3,845	-16.5	14.8	-8,137
2010	26,400	18-Jul-10	21,973	30,289	-4,427	3,889	-16.8	14.7	-8,316
2011	26,757	17-Jul-11	21,965	30,700	-4,792	3,943	-17.9	14.7	-8,735
2012	27,104	15-Jul-12	21,959	31,096	-5,145	3,992	-19.0	14.7	-9,137
2013	27,437	14-Jul-13	21,950	31,471	-5,487	4,034	-20.0	14.7	-9,521
2014	27,754	13-Jul-14	20,402	31,975	-7,352	4,221	-26.5	15.2	-11,573

Table A4 Change in Reserve Above Requirement Values from Reference Resource Scenario, Low Demand Growth, Annual Peak

Year	Reserve Above Requirement, MW						
	Reference Resource Scenario -3000 MW	Reference Resource Scenario -2000 MW	Reference Resource Scenario -1000 MW	Reference Resource Scenario	Reference Resource Scenario +1000 MW	Reference Resource Scenario +2000 MW	Reference Resource Scenario +3000 MW
2005	-2,184	-1,184	-184	816	1,816	2,816	3,816
2006	-1,940	-940	60	1,060	2,060	3,060	4,060
2007	-2,109	-1,109	-109	891	1,891	2,891	3,891
2008	-8,234	-7,234	-6,234	-5,234	-4,234	-3,234	-2,234
2009	-9,297	-8,297	-7,297	-6,297	-5,297	-4,297	-3,297
2010	-9,305	-8,305	-7,305	-6,305	-5,305	-4,305	-3,305
2011	-9,554	-8,554	-7,554	-6,554	-5,554	-4,554	-3,554
2012	-9,762	-8,762	-7,762	-6,762	-5,762	-4,762	-3,762
2013	-9,969	-8,969	-7,969	-6,969	-5,969	-4,969	-3,969
2014	-11,841	-10,841	-9,841	-8,841	-7,841	-6,841	-5,841

Table A5 Change in Reserve Above Requirement Values from Reference Resource Scenario, Median Demand Growth, Annual Peak

Year	Reserve Above Requirement, MW						
	Reference Resource Scenario -3000 MW	Reference Resource Scenario -2000 MW	Reference Resource Scenario -1000 MW	Reference Resource Scenario	Reference Resource Scenario +1000 MW	Reference Resource Scenario +2000 MW	Reference Resource Scenario +3000 MW
2005	-2,787	-1,787	-787	213	1,213	2,213	3,213
2006	-2,585	-1,585	-585	415	1,415	2,415	3,415
2007	-2,818	-1,818	-818	182	1,182	2,182	3,182
2008	-9,144	-8,144	-7,144	-6,144	-5,144	-4,144	-3,144
2009	-10,295	-9,295	-8,295	-7,295	-6,295	-5,295	-4,295
2010	-10,384	-9,384	-8,384	-7,384	-6,384	-5,384	-4,384
2011	-10,717	-9,717	-8,717	-7,717	-6,717	-5,717	-4,717
2012	-11,013	-10,013	-9,013	-8,013	-7,013	-6,013	-5,013
2013	-11,301	-10,301	-9,301	-8,301	-7,301	-6,301	-5,301
2014	-13,234	-12,234	-11,234	-10,234	-9,234	-8,234	-7,234

Table A6 Change in Reserve Above Requirement Values from Reference Resource Scenario, High Demand Growth, Annual Peak

Year	Reserve Above Requirement, MW						
	Reference Resource Scenario -3000 MW	Reference Resource Scenario -2000 MW	Reference Resource Scenario -1000 MW	Reference Resource Scenario	Reference Resource Scenario +1000 MW	Reference Resource Scenario +2000 MW	Reference Resource Scenario +3000 MW
2005	-3,090	-2,090	-1,090	-90	910	1,910	2,910
2006	-3,100	-2,100	-1,100	-100	900	1,900	2,900
2007	-3,465	-2,465	-1,465	-465	535	1,535	2,535
2008	-9,894	-8,894	-7,894	-6,894	-5,894	-4,894	-3,894
2009	-11,137	-10,137	-9,137	-8,137	-7,137	-6,137	-5,137
2010	-11,316	-10,316	-9,316	-8,316	-7,316	-6,316	-5,316
2011	-11,735	-10,735	-9,735	-8,735	-7,735	-6,735	-5,735
2012	-12,137	-11,137	-10,137	-9,137	-8,137	-7,137	-6,137
2013	-12,521	-11,521	-10,521	-9,521	-8,521	-7,521	-6,521
2014	-14,573	-13,573	-12,573	-11,573	-10,573	-9,573	-8,573

- End of Document -