OTHER MATTERS/AGREEMENTS/APPROVALS

1.0 SYSTEM IMPACT ASSESSMENT

The IESO's market rules require that any party planning to construct a new or modified connection to the IESO-controlled grid must request and receive an IESO assessment of these facilities. The IESO has completed the SIA of the proposed facilities included in the project under the IESO Connections Assessment and Approval process.

The IESO assessment addresses the impact of the proposed facilities on system operating voltage, system operating flexibility, and on the ability of other connections to deliver or withdraw power supply from the IESO-controlled grid. The IESO's SIA filed at Exhibit B, Tab 6, Schedule 2 confirms the need for this project and indicates that Hydro One's proposed transmission solution is adequate and does not adversely impact the IESO-controlled grid.

2.0 CUSTOMER IMPACT ASSESSMENT

Under the TSC, Hydro One is required to carry out a Customer Impact Assessment (CIA) in accordance with its customer connection procedures to determine the impact of those facilities on other customers. Hydro One has completed the CIA and it is included at Exhibit 6, Tab 6, Schedule 3. The new 500 kV transmission line can be incorporated without any adverse impacts on southwestern Ontario customers.

3.0 STAKEHOLDER AND COMMUNITY CONSULTATION

Prior to making this application, Hydro One met with county, regional and municipal representatives along the proposed route to brief them on the project and identify potential local impacts and concerns. Government ministries, agencies, municipal officials and staff were also consulted.

Subsequent to this application, Hydro One will undertake an extensive consultation program to inform a range of audiences about the project, seek their input, identify key issues, and develop project plans that address those issues. Approximately six public information centres (PICs) will be held at various locations along the proposed route to ensure convenient access for property owners and other stakeholders. At the public information centres, attendees will be provided project information and have an opportunity to review maps and discuss their concerns and issues with Hydro One staff and OPA representatives. Other communications will be provided on an ongoing basis through newsletters, newspapers ads, a project webpage and a toll-free telephone number. Further details can be found in Exhibit B, Tab 6, Schedule 6.

Contacts, communications and engagement with Aboriginal group representatives also began in late 2006, and continue in 2007. Further details can be found in Exhibit B, Tab 6, Schedule 7.

4.0 ENVIRONMENTAL ASSESSMENT APPROVAL

The project is subject to an Individual Environmental Assessment (EA) under Ontario's *Environmental Assessment Act*.

The EA will rely upon the previous work of the OPA to address need and alternatives. Hydro One will seek to scope the EA in accordance with the OPA's assessment and determination, the conclusions of which are found in the March 23rd OPA letter to Hydro One (Exhibit B, Tab 6, Schedule 5, Appendix 4).

Further details can be found in Exhibit B, Tab 6, Schedule 8. To meet the target in-service date, it is expected that the Terms of Reference (TOR) for the individual EA will be submitted in June 2007 and approved by September of 2007. Throughout the EA process, Hydro One will consult with various levels of government, Aboriginal groups, landowners, and other interested parties. Hydro One will apply appropriate mitigation for any identified environmental concerns and will fully document issues and Hydro One responses. An EA submission to the Ministry of Environment will be made thereafter. To meet the target in-service date, EA approval is required by September 2008.

These timelines are challenging and will depend on cooperation among stakeholders in the EA process.

5.0 COMPLIANCE WITH INDUSTRY STANDARDS AND CODES

The proposed facilities will be constructed, owned and operated by Hydro One. The design and maintenance of these facilities will be in accordance with good utility practice, as established in the TSC and in accordance with NPCC and NERC planning and operating standards.

6.0 LAND MATTERS

The proposed facilities require a widening of the existing transmission corridor by approximately 53 m to 61 m (175 ft to 200 ft). Further details can be found in Exhibit B, Tab 6, Schedule 9.

7.0 OTHER APPROVAL REQUIREMENTS

Hydro One will address the following regulatory requirements. Additional requirements may be identified during the EA process and hence the following is not to be interpreted as an all inclusive list.

- Encroachment permits and land use permits from Ministry of Transportation;
- Agreements from rail and pipeline companies for crossings; and,
- Approval and permits for road crossings, vehicle restrictions, noise control, etc., from regional and local municipalities under various municipal by-laws.

IESO SYSTEM IMPACT ASSESSMENT

IESO_REP_0382

Power to Ontario.
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Independent Electricity
System Operator
Station A, Box 4474
Toronto, Ontario M5W 4E5
t 905 855 6100

www.ieso.ca

CONNECTION ASSESSMENT & APPROVAL PROCESS

SYSTEM IMPACT ASSESSMENT REPORT

For the incorporation of a new 500kV double-circuit line between the Bruce Complex & Milton TS

Applicant: Hydro One Networks Inc.

CAA ID No. 2006-250

Transmission Assessments & Performance Department

FINAL Version

Date: 27th March 2007

System Impact Assessment Report

For the incorporation of a new 500kV double-circuit line between the Bruce Complex & Milton TS

Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Approval of the proposed connection is based on information provided to the IESO by the Hydro One Networks Inc. at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by the transmitter at the request of the IESO. Furthermore, the connection approval is subject to further consideration due to changes to this information, or to additional information that may become available after the approval has been granted. Approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed facility to the IESO-controlled grid. However, connection approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, you must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to you. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used.

Hydro One

Special Notes and Limitations of Study Results

The results reported in this system impact assessment are based on the information available to Hydro One, at the time of the study, suitable for a system impact assessment of a new transmission facility.

HYDRO ONE NETWORKS Inc.

SYSTEM IMPACT ASSESSMENT REPORT

For the incorporation of a new 500kV double-circuit line between the Bruce Complex and Milton TS

1. Summary of Conclusions & Recommendations

This Assessment has concluded that, subject to all of the following facilities being in-service prior to the completion of a proposed new 500kV line between the Bruce Complex and Milton TS, the new line will have no materially adverse effect on the IESO-controlled grid. It has therefore been recommended that a Notification of Conditional Approval to Connect be issued for this Project:

- The installation of the following reactive compensation, in addition to the shunt capacitor banks that have already been committed for installation at Detweiler TS and Orangeville TS:

  - Buchanan TS — A 3rd 170MVAr shunt capacitor bank
  - Middleport TS — Two 400MVAr shunt capacitor banks
  - Nanticoke SS — At least one 250MVAr shunt capacitor bank
  - Nanticoke SS — Dynamic compensation with a capacity of at least +350/-120MVAr

  These facilities are required to be available before a new 500kV double-circuit line is placed in-service between the Bruce Complex and Milton TS to avoid the need to implement generation rejection in response to any recognised system contingency.

  However, to mitigate the operational issues that will arise once seven units are in-service at the Bruce Complex starting in 2009 it is expected that the facilities listed above will be installed well in advance of the completion of a new 500kV line between the Bruce Complex and Milton TS.

  It is therefore expected that this requirement will be met through separate Hydro One initiatives with earlier in-service dates than that for the proposed 500kV double-circuit line between the Bruce Complex and Milton TS.

- The enhancement of the Bruce Special Protection System to allow generation rejection to be initiated in response to an expanded set of recognised contingency during periods when transmission elements are out-of-service.

With all of the facilities listed above in-service, a new 500kV double-circuit line between the Bruce Complex and Milton TS would allow all eight units at the Bruce Complex, together with all of the committed wind-turbine projects, to be accommodated without the need to employ post-contingency generation rejection in response to a recognised first contingency, with all transmission elements in-service pre-contingency.

It has also been concluded that the installation of a second 250MVAr shunt capacitor bank at Nanticoke SS, in addition to a new 500kV double-circuit line between the Bruce Complex and Milton TS, would allow 870MW of additional generating capacity to be incorporated via the 500kV busbars at the Bruce Complex, without the need to employ generation rejection in response to a recognised first contingency.

It has been recommended that the proposed layout of the 500kV switchyard at Milton TS should be reviewed with the objective of avoiding the simultaneous loss of a 500kV Milton-to-Claireville circuit and a 500kV Milton-to-Trafalgar circuit due to the failure of one of the critical breakers at Milton TS. In addition, it has been suggested that consideration be given to the installation of a second 500kV breaker at the A-station to limit the facilities that would be automatically removed from service at this switchyard in the event of a breaker-failure condition.

2. *Proposed New Transmission Facilities*

The new facilities involve the construction of a 500kV double-circuit line along the right-of-way of the existing 500kV line from the Bruce Complex to Milton TS.

One circuit of the new line is to be terminated on to the existing 500kV busbar at the Bruce A switchyard, while the other circuit is to be terminated on to the 500kV busbar at the Bruce B switchyard. Both circuits are to be terminated on to the existing 500kV busbar at Milton TS.

The new line is to be equipped with quad-585kcmil conductors and the specification calls for its ratings to be at least equivalent to those of the existing line to Milton TS.

Diagram 1 shows the proposed location of the new line in relation to the existing transmission facilities.

Subject to the necessary approvals, the new line is scheduled to be in-service by **December-2011** to coincide with the period when all eight units at the Bruce Complex are expected to be in-service simultaneously.

Facilities to be installed at the terminal stations

Diagram 2 shows the proposed arrangement of the 500kV busbars at the Bruce A & Bruce B switchyards to accommodate the two new 500kV circuits to Milton TS.

The proposed work will involve installing an additional 500kV breaker in an existing diameter at the Bruce A switchyard, while a new 500kV diameter with two new 500kV breakers will need to be established at the Bruce B switchyard.

A further, IESO-recommended, 500kV breaker has been shown in the middle diameter of the 500kV Bruce A switchyard.

Since a failure of the 500kV breaker EL560 would result in the simultaneous loss of both the E-busbar and the existing 500kV circuit B560V to Claireville TS, this situation can result in both generating units at the A-station being isolated on to the 500kV circuit to Longwood TS whenever breaker AL569 is out-of-service. This will also apply to future outages involving the new breaker that it is proposed to install in the switchyard of the A-station for the termination of the new circuit to Milton TS. Under these outage conditions, transient stability limitations would require the output of the two generating units at the A-station to be restricted.

The IESO therefore suggests that consideration be given to the installation of the additional 500kV breaker at the A-station to avoid the loss of the E-busbar at this switchyard in response to a breaker-failure condition involving the breaker EL560.

Diagram 3 shows the proposed arrangement at Milton TS which will involve the installation of a new 500kV breaker in each of two of the existing diameters.

Obtaining the necessary outages to undertake the work at this TS is expected to be challenging, particularly once seven units are all in-service at the Bruce Complex. If there is an opportunity to advance any of the proposed work so that it can be completed while there are only six units in-service, then this is expected to have major benefits.

3. *Background*

Units 1 & 2 at the Bruce A nuclear generating facility are both scheduled to return to service during 2009. However, during the period 2009 to 2011 other units at the Bruce Complex are scheduled to be removed from service for maintenance. Consequently, during the period 2009-2011 the maximum number of units that are expected to be in-service simultaneously is seven. It is only after December-2011 that all eight units at the Bruce Complex are expected to be in-service coincidently.

In addition, new wind-turbine generating projects that will have a direct impact on the flows away from the Bruce Complex have been awarded contracts under the Renewables I & II Requests for Proposals. These new facilities, whose total capacity is approximately 725MW, are scheduled to be incorporated into the system during the next two years.

230kV circuits B4V & B5V

Analysis that was performed for the earlier System Impact Assessment[1] for this area showed that to avoid the post-contingency overloading of the existing 230kV circuits B4V & B5V between Hanover TS and Orangeville TS, the maximum operating (sag) temperature of the conductors on this section would need to be increased from the present 104^{o}C to 127^{o}C. This work is presently underway and is expected to be completed before May 2009, prior to the return to service of the seventh unit at the Bruce Complex.

Reactive Compensation

The earlier SIA Report also identified the need for additional reactive support, to be provided through a mixture of dynamic facilities (synchronous condensers and/or static VAr compensators - SVCs) and shunt capacitor banks to ensure post-contingency voltage stability.

The original proposal for providing the dynamic reactive support involved converting up to four of the existing generating units at Nanticoke GS to synchronous condenser operation. Each unit when operating as a de-coupled synchronous condenser was expected to provide approximately 375MVAr of reactive support at their HV terminals.

Although it is expected that the required dynamic reactive capability will be provided by SVCs instead of through the conversion of the generating units at Nanticoke GS, it has been assumed, solely for the purpose of this Assessment, that four of the existing units at Nanticoke GS will be operated as synchronous condensers. This approach is intended to provide an indication of the amount of dynamic support that will be required at Nanticoke SS once a new 500kV line is in-service.

The earlier SIA Report also recommended that shunt capacitor banks should be installed at the following locations prior to 2009 when seven Bruce units are expected to be operational:

- Detweiler TS — a 230kV 250MVAr bank
- Orangeville TS — a 230kV 250MVAr bank (or preferably, two 125MVAr banks)
- Middleport TS — two 230kV 400MVAr banks: one on each half of the split busbar
- Nanticoke SS — two 230kV 250MVAr banks

Apart from the two shunt capacitor banks at Nanticoke SS, all of these capacitor banks have been included in the system model used for this Assessment

Cambridge-Kitchener-Waterloo-Guelph area

It was also decided, following consultation with the OPA, to install a nominal 450MW generating facility at Cambridge-Preston TS as a proxy for whatever plan is eventually recommended for enhancing the supply to the Cambridge-Kitchener-Waterloo-Guelph area. This facility would have 300MW of its capacity connected to the 230kV busbar, with the remaining 150MW connected to the 115kV busbar.

To limit the reactive support provided by this facility so that it would not unduly distort the results, the generators were set to regulate the voltage at both the 230kV and 115kV busbars at Cambridge-Preston TS to a reference voltage of 1.03 pu (226.6kV and 121.6kV, respectively).

The base case model also included the 250MVA 230/115kV auto-transformer that Hydro One is currently installing at Cambridge-Preston TS, together with a second auto-transformer at the same location. The two 250MVA 230/115kV auto-transformers that have been proposed for installation at Guelph-Campbell TS were also included in the model.

[1] SIA Report: Reference IESO_REP_0299 Issued 11th April 2006

Should the new generation capacity not be developed or delayed beyond 2011, then other facilities that would provide a comparable degree of voltage support and system reinforcement would need to be installed.

Flow-South Transfers

The recently completed SIA Report that assessed the effect of installing series capacitors in each of the 500kV Hanmer TS-to-Essa TS circuits at Nobel TS, together with SVCs at both Porcupine TS and Kirkland Lake TS, concluded that the new facilities, if augmented with additional shunt capacitor banks, would allow the Flow-South limit to be increased to 2500MW. This would then allow unrestricted operation of all of the existing facilities in the north-east (including the Sault Ste. Marie area) as well as the proposed 440MW expansion of the Mattagami River plants.

The additional shunt capacitor banks that were recommended in this SIA Report for increasing the Flow-South transfers were as follows:

- Pinard TS — 1 x 100MVAr bank
- Porcupine TS — 2 x 125MVAr banks
- Hanmer TS — 2nd 149MVAr bank
- Essa TS — 2nd 182MVAr bank

The following additional facilities were also included in the model used for this SIA, although they are to be the subject of separate SIA and Feasibility Reports:

- Little Long GS — 1 x 100MVAr shunt capacitor bank

  The need for this particular capacitor bank is to be addressed in the SIA Report for the expansion of the Mattagami River plants

- Mississagi TS — 1 x +300/-100MVAr SVC
  1 x 100MVAr shunt capacitor bank

- Algoma TS — 2nd 75MVAr shunt capacitor bank

  The need for the SVC as well as the two new shunt capacitor banks is to be addressed in the Feasibility Report for the development of the system between Sault Ste. Marie and Sudbury.

With all of these facilities in-service, the transfer on the Flow-South Interface was increased to 2500MW in all of the studies performed for this Assessment.

4. Summary of the Facilities included in the Reference System Model

In the reference base case, without the proposed double-circuit 500kV line between the Bruce Complex and Milton TS, all of the following facilities were included:

- *Series Compensation*

  Series capacitors providing 50% compensation in each of the Hanmer x Essa 500kV circuits.

- *SVCs*

Porcupine TS	One +300/-100MVAr 230kV-connected SVC
Kirkland Lake TS	One +200/-100MVAr 115kV-connected SVC
Mississagi TS	One +300/-100MVAr 230kV-connected SVC

- *Shunt Capacitor Banks*

Little Long SS	1 x 100MVAr shunt capacitor bank
Pinard TS	1 x 100MVAr shunt capacitor bank
Porcupine TS	2 x 125MVAr shunt capacitor banks
Hanmer TS	2nd 149MVAr shunt capacitor bank

Essa TS	2nd	182MVAr shunt capacitor bank
Mississagi TS	1 x	100MVAr shunt capacitor bank
Algoma TS	2nd	75MVAr shunt capacitor bank
Detweiler TS	2nd	250MVAr shunt capacitor bank
Orangeville TS	2 x	125MVAr shunt capacitor banks
Buchanan TS	3rd	170MVAr shunt capacitor bank
Middleport TS	2 x	400MVAr shunt capacitor banks

- *230/115kV auto-transformers*

Cambridge-Preston TS	Two 250MVA 230/115kV auto-transformers
Guelph-Campbell TS	Two 250MVA 230/115kV auto-transformers

- *Generating Facilities*

  Cambridge-Preston TS — A 300MW facility connected to the 230kV busbar, and
  A 150MW facility connected to the 115kV busbar

  In addition, the following generating facilities that have recently been awarded contracts and are either under construction or scheduled to be completed by 2009, were included in the system model:

  - Calpine - Greenfield Energy Centre 1005MW
  - Invenergy - St Clair Power 570MW
  - Sithe - Goreway 1015MW
  - Portlands Energy Centre 658MW
  - Halton Hills 680MW

- *Synchronous Condensers*

  Four units converted at Nanticoke GS, each rated at 400MVAr, with two units connected to the 500kV & the 230kV busbars, respectively.

5. Forecast Primary Demand

The primary demand used in the model was 28400MW, representing the value that has been forecast for the extreme weather condition for the summer-2010.

6. Transmission Line Ratings

The long-term emergency ratings for the critical transmission circuits that were used in this Assessment are summarised in Table 1.

7. Study Criteria

Load Flow Analysis

- A constant-MVA representation was used for all system loads in both the pre-and post-contingency load flow analysis.
- All under-load tap-changers (ULTCs) that are under automatic control were allowed to move post-contingency.
- All switched shunt devices that are under automatic control were allowed to move post-contingency.
- To represent the new generation capacity that could be incorporated once the new line is operational, two fictitious generating units were assumed at the Bruce Complex: one connected to the 500kV busbar at the Bruce A switchyard and the other to the 500kV busbar at the Bruce B switchyard.

  Each generator was assumed to have the same characteristics as the Bruce B units and to be connected to their respective 500kV busbars via similar step-up transformers.

TABLE 1	***Long-Term Emergency Ratings for the 'Critical' Circuits in the Study Area*** *for an ambient temperature of 35°C and with a wind speed of* ***0 to 4km/hr****.*		
Circuits	***Sag Temp***	***Long-Term Emergency Rating at 127°C or Sag Temperature, if lower***	***MVA Rating***
500kV Circuits			*at 520kV*
B560V & B561M: Bruce x Milton			
Quad - 585kcmil	127°C	3660A	3296MVA
B560V & M571V: Milton x Claireville			
Quad - 585kcmil	B560V 127°C M571V 130°C	3660A	3296MVA
M570V & V586M: Milton x Claireville			
Quad - 585kcmil	127°C	3660A	3296MVA
B562L & B563L: Bruce x Longwood			
Quad - 585kcmil	127°C	3660A	3296MVA
N582L: Longwood x Nanticoke			
Quad - 585kcmil	127°C	3660A	3296MVA
230kV Circuits			*at 240kV*
B4V & B5V: Bruce x Orangeville			
1277.5kcmil Bruce to Hanover	127°C**	1430A**	594MVA
1192.5kcmil Hanover to Orangeville	127°C***	1400A	582MVA
B22D & B23D: Bruce x Detweiler			
1192.5kcmil Bruce to Seaforth	150°C	1400A	582MVA
932.7kcmil Seaforth to Stratford	150°C	1200A	582MVA
932.7kcmil Stratford to Detweiler	120°C	1150A	582MVA
115kV Circuits			*at 121kV*
S2S: Owen Sound x Stayner			
477.0kcmil Owen Sound to Meaford	150°C	770A	161MVA
477.0kcmil Meaford to Stayner	128°C	770A	161MVA

Note: * Hydro One is planning to increase the sag temperature of this line to from 78°C to 100°C

** For planning purposes, operation at this current is to be limited to 8 hours per year because the conductors are classified as of 'high-aluminum content'

*** Hydro One plans to increase the sag temperature of this section of the line from 104°C to 127°C

Power-Voltage (PV) Analysis

For the condition with a new 500kV double-circuit line between the Bruce Complex and Milton TS

- A constant-MVA representation was used for all system loads
- For each of the system arrangements that were studied, the *post-contingency condition* following the loss of the 500kV Bruce-to-Claireville (B560V) and the Bruce-to-Milton (B561M) circuits was used as the reference. All ULTCs and switch shunts that are under automatic control were allowed to move prior to starting the PV analysis.
- To increase the Flow Away from the Bruce Complex (FABC), the outputs of the two fictitious generators were increased in unison.
- To compensate for the increase in generation output at the Bruce Complex, the output of those generating facilities at Darlington GS were reduced accordingly.
- In accordance with the IESO's criteria, the limiting transfer would correspond to a value 5% less than the voltage instability point (or knee) of the PV curve.

Stability Analysis

Fault clearance times

The following times were used for the contingency involving the 500kV circuits B560V & B561M:

		Elapsed Time
• Clearance of the fault at the terminals at the Bruce Complex		66msec
• Clearance of the fault at the Milton TS & Claireville TS terminals	+ 26msec	92msec

Provision of a margin of 10% on the Limiting Transfers

- To provide the required 10% margin, negative load was added to the busbars at the Bruce Complex to increase the Flow Away From the Bruce Complex (FABC) by 10%.

8. Reference Load Flow Diagrams with all eight Bruce units in-service

For these studies, the transfers across the Flow-South Interface and across the Negative-BLIP Interface (with a flow towards the GTA) were adjusted to 2500MW and 1500MW, respectively.

Diagram 4 shows the flow distribution that would occur on the existing transmission facilities, without the new 500kV line to Milton TS in-service, for the condition with all eight units at the Bruce Complex together with all of the committed wind-turbine projects, in operation.

In particular, the following should be noted:

i. That with no shunt capacitor banks at Nanticoke SS, the total reactive power output from the synchronous condensers at Nanticoke GS is shown as 763MVAr. This suggests that at least two 250MVAr shunt capacitor banks would need to be included at this location to minimise the pre-contingency output from the four synchronous condensers.

ii. That the transmission losses on the Ontario System, for this particular operating scenario, are shown to total 1355MW.

iii. That the flows on the principal circuits would be as shown in the following Table:

Circuit *500kV*		*Recorded Flows*		*Continuous Ratings at 93^{o}C*
B560M	Bruce to Milton TS	1875MW : 267MVAr	2014A	2815A
B561V	Bruce to Claireville TS	2146MW : 372MVAr	2311A	2815A
B562L	Kingsbridge II to Longwood TS	644MW : 98MVAr	688A	2815A
B563L	Kingsbridge II to Longwood TS	594MW : 177MVAr	628A	2815A
N582L	Longwood TS to Nanticoke SS	1492MW : 37MVAr	1579A	2815A
230kV				
B4V & B5V	Leader Wind to Hanover TS	388MW : 34MVAr	907A	1080A
	Melancthon Wind to Orangeville	420MW : 46MVAr	1000A	1060A
B22D & B23D	Ripley Wind to Seaforth	311MW : 55MVAr	734A	1060A

Diagram 5 shows the corresponding flow distribution with the proposed Bruce-to-Milton 500kV line in-service.

Similarly, the following should be noted from this Diagram:

i. That with no shunt capacitor banks at Nanticoke SS, the total MVAr output from the synchronous condensers at Nanticoke GS is shown as 380MVAr. This represents a reduction of over 380MVAr as a result of installing the new line: equivalent to the output of one of the synchronous condensers.

   It also suggests that at least one 250MVAr shunt capacitor bank should be included in the system model to minimise the pre-contingency output from the synchronous condensers. This would allow the maximum support to remain available from these devices for the post-contingency condition.

ii. That with the new 500kV line in-service, the flows on the principal circuits would be as follows:

Circuit *500kV*		*Flow*		*Continuous Rating : 93^{o}C*
B560M	Bruce (A) to Milton TS	1228MW : 56MVAr	1302A	2815A
B561V	Bruce (B) to Claireville TS	1267MW : 84MVAr	1342A	2815A
B(A) x M	Bruce (A) to Milton TS - *NEW*	1244MW : 66MVAr	1319A	2815A
B(B) x M	Bruce (B) to Milton TS - *NEW*	1264MW : 80MVAr	1338A	2815A
B562L	Kingsbridge II to Longwood TS	324MW : 101MVAr	357A	2815A
B563L	Kingsbridge II to Longwood TS	271MW : 187MVAr	290A	2815A
N582L	Longwood TS to Nanticoke SS	1065MW : 13MVAr	1120A	2815A
230kV				
B4V & B5V	Leader Wind to Hanover TS	297MW : 20MVAr	685A	1080A
	Melancthon Wind to Orangeville	333MW : 77MVAr	806A	1060A
B22D & B23D	Ripley Wind to Seaforth	253MW : 31MVAr	594A	1060A

Comparing the results in the two preceding Tables shows that the new line would result in a reduction of approximately 640MVA in the combined flow on the 500kV Bruce-to-Longwood TS circuits. It would also reduce the flow on the 500kV circuit between Longwood TS and Nanticoke SS by approximately 430MVA.

In addition, the new 500kV line would reduce the flows on the 230kV circuits, particularly on that section of circuits B4V & B5V between the Melancthon Wind Projects and Orangeville TS. Without the new line in-service, these circuits are shown to be loaded to 1000A, which would be close to their continuous rating of 1060A. With the new 500kV line in-service, the flows on this section are reduced by approximately 200A to 806A.

iii. That the two 230/115kV auto-transformers that it is proposed to install at Guelph-Campbell TS would supply approximately 200MW to the 115kV system. This would have the effect of increasing the loading on the 230kV circuits D6V & D7V between Detweiler TS and Orangeville TS while unloading the 230/115kV auto-transformers at Burlington TS by approximately 210MW (the difference reflects the reduction in the transmission losses).

iv. That with the proposed 115kV-connected generation at Cambridge-Preston TS, the transfers through the two 230/115kV auto-transformers at that TS would be reduced to approximately 80MW.

v. That the new 500kV line between the Bruce Complex and Milton TS would result in circuit M585M between Middleport TS and Milton TS 'floating' i.e. carrying close to zero power. However, because of the line capacitance there would be a significant reactive power flow from this circuit into Milton TS, providing valuable voltage support. The companion circuit V586M, because it is terminated directly into Claireville TS, is shown to carry approximately 300MW.

vi That the transmission losses for the Ontario System, for the same operating scenario, but with the new 500kV line in-service, are shown to total 1236MW. This would represent a reduction in the system losses of 119MW.

8.1 FABC (Flow Away from the Bruce Complex) transfer

The FABC transfer shown in Diagram 5 is 6461.9MW. Since this corresponds to the actual flows that would be monitored in the operational environment it therefore reflects the local transmission losses as well as the load at Douglas Point TS.

This transfer corresponds to the following theoretical output from the Bruce Complex:

4 units at the Bruce A Station, each with a rated output of 805MW	3220MW
less a station service supply of 55MW for each unit	- 220MW
Net Output from the A station	*3000MW*
4 units at the Bruce B station, each with a rated output of 940MW	3760MW
less a station service supply of 50MW for each unit	- 200MW
Net Output from the B station	*3560MW*
Combined net output from the A & B Stations	*6560MW*

The transmission losses, together with the load at Douglas Point TS, therefore total approximately 100MW (6560MW - 6461.6MW).

For the purpose of this Assessment, except for the load flow studies where the actual flows are available for determining the FABC transfer, all other references to the FABC transfer use the combined net output from the A & B stations. To distinguish between the two values, the following convention has been adopted:

FABC	*refers to the actual transfer away from the Bruce Complex, calculated by summing the appropriate flows.*
*FABC**	*refers to the combined net output from the A & B stations, ignoring both the local transmission losses and the load at Douglas Point TS*

As shown above, with all eight units in-service at the Bruce Complex, the difference between the two values will be approximately 100MW.

8.2 Contingency Conditions

With a new 500kV double-circuit line constructed between the Bruce Complex and Milton TS and terminated into Milton TS as shown in Diagram 3 (Proposed Additions to the Milton 500kV Switchyard), the following would represent the more critical contingency conditions that could then occur:

- A double-circuit contingency involving either the existing 500kV line to Milton TS and Claireville TS (circuits B560V & B561M) or the new 500kV line to Milton TS
- A double-circuit contingency involving the existing 500kV Milton-to-Claireville line (circuits B560V & M571V)
- A breaker-failure condition involving breaker L61L71, breaker KL570 or the new H-busbar breaker that would result in the simultaneous loss of a Bruce-to-Milton & a Milton-to-Claireville circuit (circuits B561M & M571V; circuits BxxxM & M570V; or circuits ByyyM & M571V)
- A breaker-failure condition involving either breaker L70L73 or breaker HL573 that would result in the simultaneous loss of a Milton-to-Claireville & a Milton-to-Trafalgar circuit (circuits M570V & M573T or circuits M571V & M573T)

Analysis was performed to determine the effect of each of these contingency conditions:

Post-contingency Results: *for the case with 8 Bruce units, together with all of the committed wind-projects, and with the new 500kV Bruce-to Milton line in-service*

i. For a contingency involving the existing 500kV double-circuit line from the Bruce Complex to Milton TS & Claireville TS

The results from the study for this contingency condition have been summarised in Diagram 6.

This shows approximately 60% (1492MW) of the pre-contingency flow on the faulted circuits being transferred to the new 500kV line into Milton TS with a further 27% (675MW) appearing on the 500kV circuits into Longwood TS. The remaining 13% appears primarily as increased transfers over the 230kV circuits from the Bruce Complex to Detweiler TS and to Orangeville TS.

With lower post-contingency transfers to Nanticoke SS, via Longwood TS, the resulting net increase in the reactive power demand at Nanticoke SS is therefore only 208MVAr and this would be well within the capability of a single synchronous condenser at Nanticoke GS.

The increase in the transmission losses for this condition with no additional generation capacity incorporated is shown to be approximately 119MW (1355MW - 1236MW).

ii. For a double-circuit contingency involving the existing 500kV double-circuit line between Milton TS & Claireville TS: circuits B560V & M571V

The results from this study, which have been summarised in Diagram 7, show a post-contingency flow of 2526MVA on the remaining 500kV Milton x Claireville circuit. Although this is relatively high at 2790A, this flow would still be within the *continuous* rating of 2815A for this circuit, and well within its long-term emergency rating of 3660A.

iii. For a breaker failure condition that would result in the simultaneous loss of a 500kV Bruce x Milton circuit & a 500kV Milton x Claireville circuit

Since this contingency condition would result in the loss of only a single 500kV circuit from the Bruce Complex, the post-contingency flows on each of the remaining circuits, as summarised in Diagram 8, are shown to increase to a maximum of approximately 1670A, which would be well within their continuous ratings of approximately 2800A. Similarly, the post-contingency flows on the circuits between Milton TS and Claireville TS are also shown to remain well within their continuous ratings.

iv. For a breaker failure condition that would result in the simultaneous loss of a 500kV Milton x Claireville circuit & a 500kV Milton x Trafalgar circuit

The results for this contingency condition have been summarised in Diagram 9 and these show that the transfers through the T14 unit that would remain in-service connected to circuit M572T post-contingency (1088MVA), would be only marginally within its 10-day long-term emergency rating of 2625A or approximately 1090MVA.

Diagram 10 shows the results for the same contingency condition but with a reduced transfer across the QFW Interface. These results show that the 10-day long-term emergency rating would be exceeded. Similar results would be expected for the condition with a reduced transfer across the Negative-BLIP Interface.

It is therefore recommended that the proposed layout of the 500kV busbar at Milton TS be reviewed to avoid the simultaneous loss of the 500kV circuit M573T and either of the 500kV Milton-to-Claireville circuits due to a breaker-failure condition involving either of the 500kV breakers L70L73 or HL573.

Outage Conditions involving the 500kV Milton x Claireville circuits

Diagram 11 shows the flows with one of the Milton TS to Claireville TS circuits (M571V) out-of-service, either for maintenance or because of a fault.

In this Diagram, the flow on each of the 500kV circuits to Trafalgar TS is shown to remain within the 10-day limited-time-rating (~1090MVA) of the auto-transformer on to which each circuit is terminated.

Diagram 12 shows the corresponding flows should the companion circuit (M570V) suffer a contingency. This would result in flows through the 500/230kV auto-transformers at Trafalgar TS that would exceed their 10-day limited-time ratings, although they would remain within the 15-minute limited-time-ratings of these units.

Analysis has shown that to achieve the required reduction in the flows through the auto-transformers to respect their 10-day limited-time-ratings, the output from the Bruce complex would need to be reduced by approximately 650MW.

9. *Capability to incorporate additional generating capacity*

The construction of a new 500kV transmission line between the Bruce Complex and Milton TS is intended to allow additional generating capacity to be incorporated into the system beyond the eight units at the Bruce Complex and all of the committed wind-turbine projects, without the need to initiate generation rejection in response to any recognised first contingency.

Analysis was therefore performed to quantify the enhanced incorporation capability that the new line would be expected to provide.

In the absence of any definitive information as to where any new generation capacity is likely to be located and the manner in which it would be incorporated, it was decided to concentrate all the new generation capacity directly on to the 500kV busbars at the Bruce Complex. The intent was to avoid introducing unintentional circuit loading issues on the 230kV system that could indirectly influence the results.

9.1. Study Results

With a new 500kV line between the Bruce Complex and Milton TS and with additional generating capacity incorporated via the 500kV busbars at the Bruce Complex

9.1.1 Power-Voltage Analysis

PV-analysis was performed for the arrangement shown in Diagrams 5 & 6 to determine its voltage stability limit, following the loss of the existing 500kV double-circuit line, B560V & B561M. The FABC* transfer was increased by adjusting the output of the two fictitious generators that were added at the Bruce Complex; with one unit connected to the 500kV busbar at the A station and the other unit to the 500kV busbar at the B station.

Diagram 13 shows the resulting voltage curves together with a curve showing the available reactive power from the generating units in south-western Ontario.

The FABC* Transfer at which the study terminated was 7821MW and this corresponded to the situation where the generating units within the GTA (at Pickering GS, Darlington GS and the Sithe-Goreway facility) reached their maximum MVAr outputs.

Applying a 5% margin to this transfer would therefore give a voltage instability limit of **7430MW** for the FABC* Transfer with the new 500kV line in-service.

This would allow approximately **870MW** of additional generating capacity (7430MW - the FABC transfer for the existing 8 units at the Bruce Complex of 6560MW) to be incorporated.

9.1.2 Load Flow Analysis

Pre-contingency

Diagram 14 shows the results of the pre-contingency analysis for the condition with the new 500kV line in-service and with the additional 870MW of generating capacity incorporated via the 500kV busbars at the Bruce Complex.

This shows an increase of 57MW (1292.9MW - 1236.3MW from Diagram 5) in the system losses as a result of incorporating the additional 870MW of generating capacity. In addition, the reactive power output from the synchronous condensers at Nanticoke GS is shown to have increased to 475MVAr; once again confirming the need for at least one 250MVAr shunt capacitor bank at Nanticoke SS.

The following Table shows the changes recorded in the circuit flows resulting from the addition of 870MW of new generating capacity at the Bruce Complex.

This shows that approximately 75% of the output from the new generating facilities would appear as increased flows on the four 500kV circuits from the Bruce Complex to Milton TS and Claireville TS. A further 16% would appear as increased flows on the two 500kV circuits from the Bruce Complex to Longwood, while the majority of the remainder (8%) would appear as increased flows on the 230kV circuits to Orangeville TS and Detweiler TS.

With such a high proportion of the output from the Bruce Complex flowing directly over the Bruce-to-Milton corridor, these results clearly demonstrate the benefit of installing a new transmission line into Milton TS from the Bruce Complex.

Changes in the Flow Distribution arising from the 870MW of New Generating Capacity at the Bruce Complex						
			New Generation Capacity			
Circuit			None Diagram No. 5	870MW Diagram No. 14	*Increase*	
500kV	B560V	Bruce x Claireville	1228.1MW	1396.1MW	167.7MW	19.2%
	B561M	Bruce x Milton	1267.2MW	1427.9MW	160.7MW	18.5%
	New BxM Circuit from the 'A' station		1244.0MW	1403.1MW	159.1MW	18.3%
	New BxM Circuit from the 'B' station		1264.1MW	1424.6MW	160.5MW	18.4%
	B562L	Bruce x Longwood	324.3MW	394.8MW	70.5MW	8.1%
	B563L	Bruce x Longwood	270.9MW	342.9MW	72.0MW	8.3%
230kV	B4V & B5V	Bruce x Orangeville	590.5MW	634.2MW	43.7MW	5.0%
	B22D & B23D	Bruce x Detweiler	505.5MW	531.7MW	26.2MW	3.0%
115kV	S2S Owen	Sound x Stayner	66.9MW	75.3MW	8.4MW	1.0%
				Total	*868.8MW*	*99.8%*

Analysis was also performed to determine the effect that each of the same contingency conditions that were examined previously for the scenario with no additional generating capacity incorporated, would have.

Post-contingency Results: *for the case with 8 Bruce units, together with an additional 870MW of new generation capacity as well as all of the committed wind-projects, and with the new 500kV Bruce-to Milton line in-service*

i. For a contingency involving the existing 500kV double-circuit line from the Bruce Complex to Milton TS & Claireville TS

Diagram 15 shows the load flow results following a double-circuit contingency involving the loss of circuits B560V & B561M. This shows a combined output from the synchronous condensers at Nanticoke GS of 751.6MVAr; representing an increase over their pre-contingency output of 277MVAr. The increase in transmission system losses between the pre- and post-contingency conditions is shown to total 152MW (1444.8MW - 1292.9MW).

The post-contingency flows on the 500kV & 230kV circuits are all shown to remain well within their long-term-emergency ratings.

This is also true with respect to the 115kV line between Owen Sound TS and Stayner TS. The post-contingency flow on the section into Stayner TS is shown as 558A which would be well within its LTE rating of 770A. Consequently, automatic cross-tripping of this circuit, as recommended in the Assessment Report for the Bruce series compensation, would not be required with this amount of new generating capacity incorporated.

ii. For a double-circuit contingency involving the existing 500kV double-circuit line between Milton TS & Claireville TS: circuits B560V & M571V

The results from this study have been summarised in Diagram 16. These show that as a result of incorporating the additional generating capacity, the post-contingency flow on the remaining 500kV Milton-to-Claireville circuit would increase to 3210A (from 2815A). However, this would still be within its long-term emergency rating of 3660A.

iii. *For a breaker failure condition that would result in the simultaneous loss of a 500kV Bruce x Milton circuit & a 500kV Milton x Claireville circuit*

The results from this study, as summarised in Diagram 17, show that although the incorporation of the new generating capacity at the Bruce Complex would result in increased post-contingency flows, all of the flows, including those on the 230kV circuits from the Bruce Complex, would remain within their *continuous* ratings.

iv. *For a breaker failure condition that would result in the simultaneous loss of a 500kV Milton x Claireville circuit & a 500kV Milton x Trafalgar circuit*

Diagram 18 shows the results from this study. These show a post-contingency transfer of approximately 1160MVA through the remaining 500/230kV auto-transformer at Trafalgar TS, which would exceed its 10-day limited-time-rating of 1090MVA.

Furthermore, as discussed in Section 8.2 iv. for the same contingency condition but with no additional generating capacity incorporated at the Bruce Complex, the transfer through the remaining auto-transformer would be expected to increase in response to lower transfers across the QFW and/or Negative-BLIP Interfaces than were assumed in this analysis.

The recommendation to review the proposed layout of the 500kV busbar at Milton TS so as to avoid the simultaneous loss of the 500kV circuit M573T and either of the 500kV Milton-to-Claireville circuits due to a breaker-failure condition involving either of the 500kV breakers L70L73 or HL573, would therefore be even more relevant with the added generation capacity.

Outage Conditions involving the 500kV Milton x Claireville circuits

Diagram 19 shows the flows with one of the Milton TS to Claireville TS circuits (M571V) out-of-service, either for maintenance or because of a fault.

In this Diagram, the transfer through each of the 500kV auto-transformers at Trafalgar TS is shown to be approximately 910MVA, which would be within their 10-day limited-time-rating (~1090MVA). However, as before, these transfers would be expected to increase with lower transfers across the QFW and/or Negative-BLIP Interfaces, and could therefore exceed the emergency ratings of the auto-transformers.

Diagram 20 shows the corresponding flows should the companion circuit (M570V) suffer a contingency. This would result in transfers of approximately 1370MVA through each of the 500/230kV auto-transformers at Trafalgar TS, and these would be well in excess of their 10-day limited-time ratings.

These results show that with additional generation capacity incorporated via the 500kV busbars at the Bruce Complex, outages involving the transmission facilities that form the Milton-to-Claireville corridor would be especially challenging operationally. This corridor would therefore benefit from the implementation of measures that would limit the severity of the critical outage conditions.

9.2 Transient Stability Analysis

A transient stability study was performed for the arrangement with the new 500kV line in-service to confirm that the corresponding transient stability limit would be less restrictive than the voltage stability limit that has been determined from the PV-analysis.

For this study, rather than attempting to establish an actual transient stability limit for the FABC* Transfer, it was considered sufficient to demonstrate that the system would remain stable at an FABC* Transfer (after applying the required 10% margin) that was higher by an appropriate margin than the voltage stability limit determined from the PV-analysis.

Since the voltage stability limit for this condition (after applying the 5% margin) corresponded to an FABC* Transfer of 7430MW, then the transient stability analysis would need to demonstrate that the generating units would remain stable for an FABC* Transfer of *at least* 8173MW (7430MW x 1.1) in order to provide the required margin of 10% as stipulated in the IESO's criteria.

Diagram 20 shows the results obtained with an FABC Transfer of 8610MW. This shows that the units remain stable with an initial angular swing of less than 30^o. It is therefore expected that the FABC Transfer at which stability would be lost would be substantially higher.

After applying the required 10% margin, this FABC Transfer would be equivalent to a 'limit' of 7827MW. However, since this Transfer corresponds to the actual flows and not the net output of the generating units at the Bruce Complex, this 'limit' would therefore correspond to an FABC* Transfer at least 100MW higher, or approximately 7930MW. This would therefore be 500MW or at least 6.7% higher than the corresponding voltage stability limit of 7430MW.

This study therefore confirms that the voltage stability limit for the FABC* Transfers would be more restrictive than the transient stability limit.

10. Summary of the studies for the new 500kV line between the Bruce Complex and Milton TS

The studies have shown that, under the following operating conditions,

- With a transfer of 2500MW across the Flow-South Interface
- With a transfer of 1500MW across the Negative-BLIP Interface, and
- With a primary demand of 28400MW

and with *a new 500kV double-circuit line between the Bruce Complex and Milton TS,* the amount of new generating capacity that could be incorporated into the system via the 500kV busbars at the Bruce Complex, in addition to the following generating facilities,

- All eight units at the Bruce Complex, and
- All 725MW of the committed wind-turbine Projects

would be limited to a maximum of **870MW** to avoid the onset of voltage instability at the busbars within the GTA.

11. Reactive Compensation Requirements

This Assessment has confirmed that apart from the four synchronous condensers that were assumed to be in-service at Nanticoke GS, all of the following reactive compensation facilities will be required to be in-service once the new line is completed.

Detweiler TS	A 2nd 250MVAr shunt capacitor bank
Orangeville TS	Two 125MVAr shunt capacitor banks
Buchanan TS	A 3rd 170MVAr shunt capacitor bank
Middleport TS	Two 400MVAr shunt capacitor banks

The reactive power requirements at Nanticoke GS, *with all transmission elements in-service*, have been summarised in Table 3. This shows that, with no additional generating capacity incorporated, at least one 250MVAr shunt capacitor bank will be required at Nanticoke SS to limit the amount of dynamic reactive support that would need to be installed.

TABLE 3	***Reactive Power Requirements at Nanticoke SS with a new 500kV line to Milton TS***				
Additional Generating Capacity Incorporated at the Bruce Complex	***Diagram No.***	***System Condition***	***Reactive Power Output from the Synchronous Condensers***		
			Recorded Value	***Increase***	***Effective Output with shunt capacitor banks at Nanticoke***
None	5	*Pre-contingency*	379.6MVAr		*129.6MVAr + 1 x 250MVAr*
	6	*Post-contingency*	587.8MVAr	*208.2MVAr*	*337.8MVAr + 1 x 250MVAr*
870MW	8	*Pre-contingency*	498.0MVAr		*-2.0MVAr + 2 x 250MVAr*
	9	*Post-contingency*	682.8MVAr	*184.8MVAr*	*182.8MVAr + 2 x 250MVAr*

The above Table shows that with no additional generating capacity incorporated, approximately 600MVAr of reactive support would be required at Nanticoke SS to maintain acceptable post-contingency voltages. This is shown to increase to approximately 700MVAr for the condition with 870MW of new generation capacity incorporated into the system via the 500kV busbars at the Bruce Complex. However, the portion of these requirements that would need to be provided by dynamic reactive power devices could be reduced by placing shunt capacitor banks in-service at Nanticoke SS pre-contingency.

The final column of the above Table shows that with one 250MVAr capacitor bank in-service pre-contingency, the amount of dynamic reactive support that would be required post-contingency to maintain acceptable voltages for the condition with no additional generating capacity incorporated would be approximately 340MVAr.

Similarly, for the condition with 870MW of additional generating capacity in-service, placing two 250MVAr shunt capacitor banks in-service pre-contingency would reduce the amount of dynamic reactive support that would be required post-contingency to approximately 185MVAr.

However, with lesser amounts than the 870MW of additional generating capacity that has been assessed, the devices that provide the dynamic reactive power would need to have a VAr absorption capability to allow the second 250MVAr shunt capacitor bank to be placed in-service pre-contingency.

It is therefore recommended that with the new 500kV line to Milton TS in-service, the *minimum* amount of reactive compensation that will be required at Nanticoke SS to allow up to 870MW of additional generating capacity to be incorporated will be as follows:

- Two 250MVAr shunt capacitor banks, and
- Dynamic reactive power device(s) with a reactive power capability range of at least +350MVAr and -120MVAr

It should also be stressed that with any transmission facilities out-of-service that result in increased post-contingency transfers via those facilities between Longwood TS/Buchanan TS and Nanticoke SS/Middleport TS, the reactive power requirements in the Nanticoke area will increase beyond those shown in Table 3.

Operation during the interim period once seven units are in-service at the Bruce Complex

Although this is considered to be outside the scope of this Assessment, analysis has shown that the reactive power requirements at Nanticoke SS during this period prior to the new 500kV line being completed when seven units are in-service at the Bruce Complex will be significantly greater than those summarised in Table 3.

It is therefore assumed that the reactive compensation requirements detailed above will be met through a separate Hydro One initiative with an earlier in-service date than that for the new 500kV line.

Furthermore, on the assumption that the reactive power facilities that will be installed at Nanticoke SS to limit the extent of any operational constraints that might need to be imposed during the interim period,will exceed the requirements detailed above, it is recommended that consideration be given to retaining at least some of these additional facilities in-service once the new line becomes available. With additional reactive support available at Nanticoke SS, the extent of any operational restrictions that will be required during periods when transmission facilities are out-of-service following the completion of the new 500kV line could be limited.

12. Bruce Special Protection System

Although the analysis has shown that all of the committed generating facilities as well as further new generating capacity could be incorporated without having to initiate generation rejection in response to a contingency while all transmission elements are in-service, generation rejection will still be required whenever transmission elements are out-of-service.

It will therefore be necessary to enhance the Bruce SPS to expand the number of contingency conditions to which it can respond.

13. Customer Impact Assessment

Hydro One Networks Inc. has completed a Customer Impact Assessment for this Project and concluded that the proposed facilities will have no adverse impact on any of their customers.

14. Notification of Approval of the Connection Proposal

This Assessment has concluded that, subject to all of the following facilities being in-service prior to the completion of the new 500kV line, this proposal will have no materially adverse effect on the IESO-controlled grid:

- The installation of the following reactive compensation, in addition to the shunt capacitor banks that have already been committed for installation at Detweiler TS and Orangeville TS:

    - Buchanan TS — A 3rd 170MVAr shunt capacitor bank
    - Middleport TS — Two 400MVAr shunt capacitor banks
    - Nanticoke SS — At least one 250MVAr shunt capacitor bank
    - Nanticoke SS — Dynamic compensation with a capacity of at least +350/-120MVAr

    However, while the facilities listed above must be available once the new 500kV line is in-service to avoid the need to implement generation rejection in response to any recognised system contingencies, it is expected that they will be installed prior to the new line being placed in-service to mitigate the operational issues that will arise once seven units are in-service at the Bruce Complex starting in 2009.

    This requirement is therefore expected to be met through separate Hydro One initiatives with earlier in-service dates than that of the new 500kV line.

- The enhancement of the Bruce Special Protection System

It is therefore recommended that a Notification of Conditional Approval to Connect be issued for this Project.

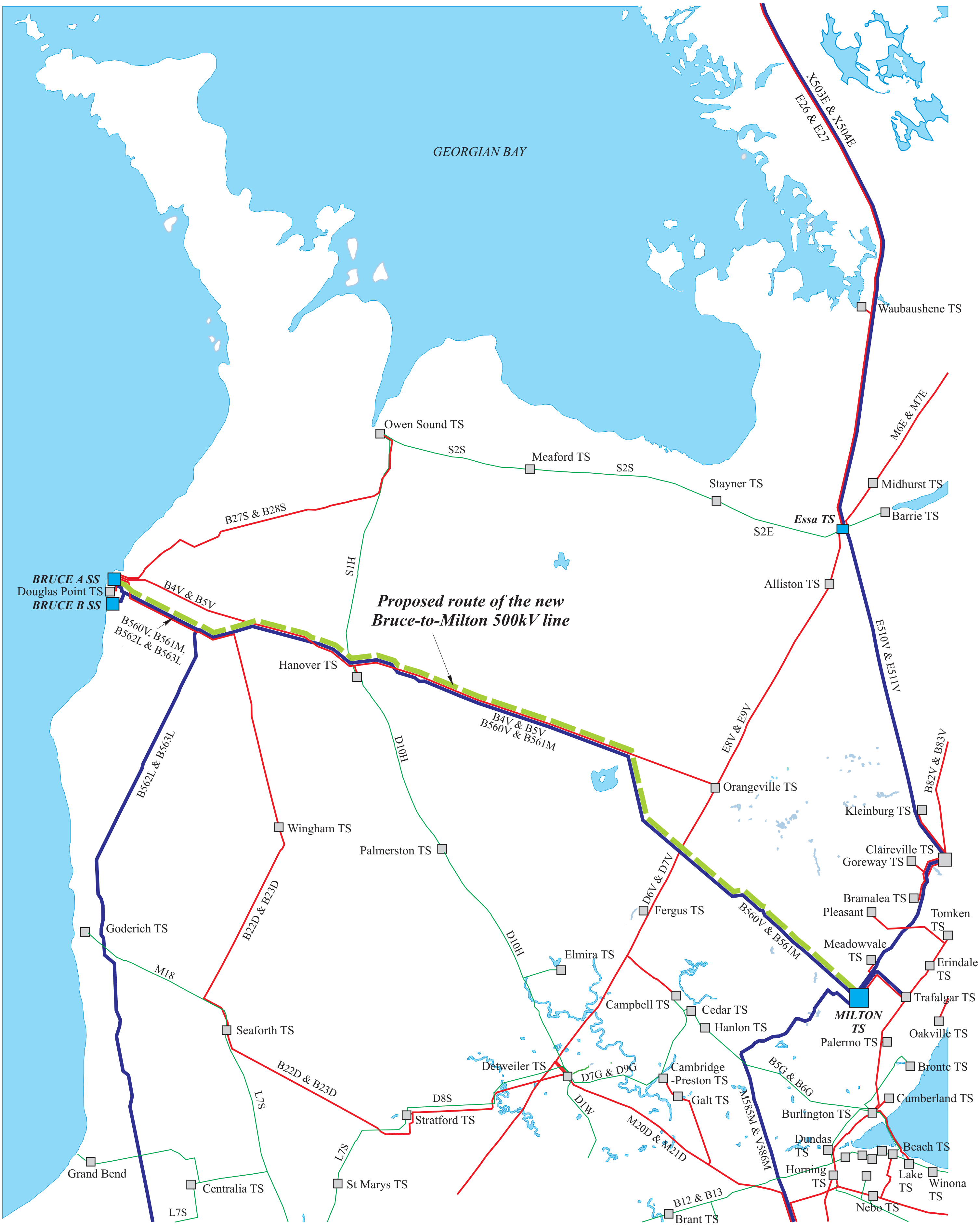
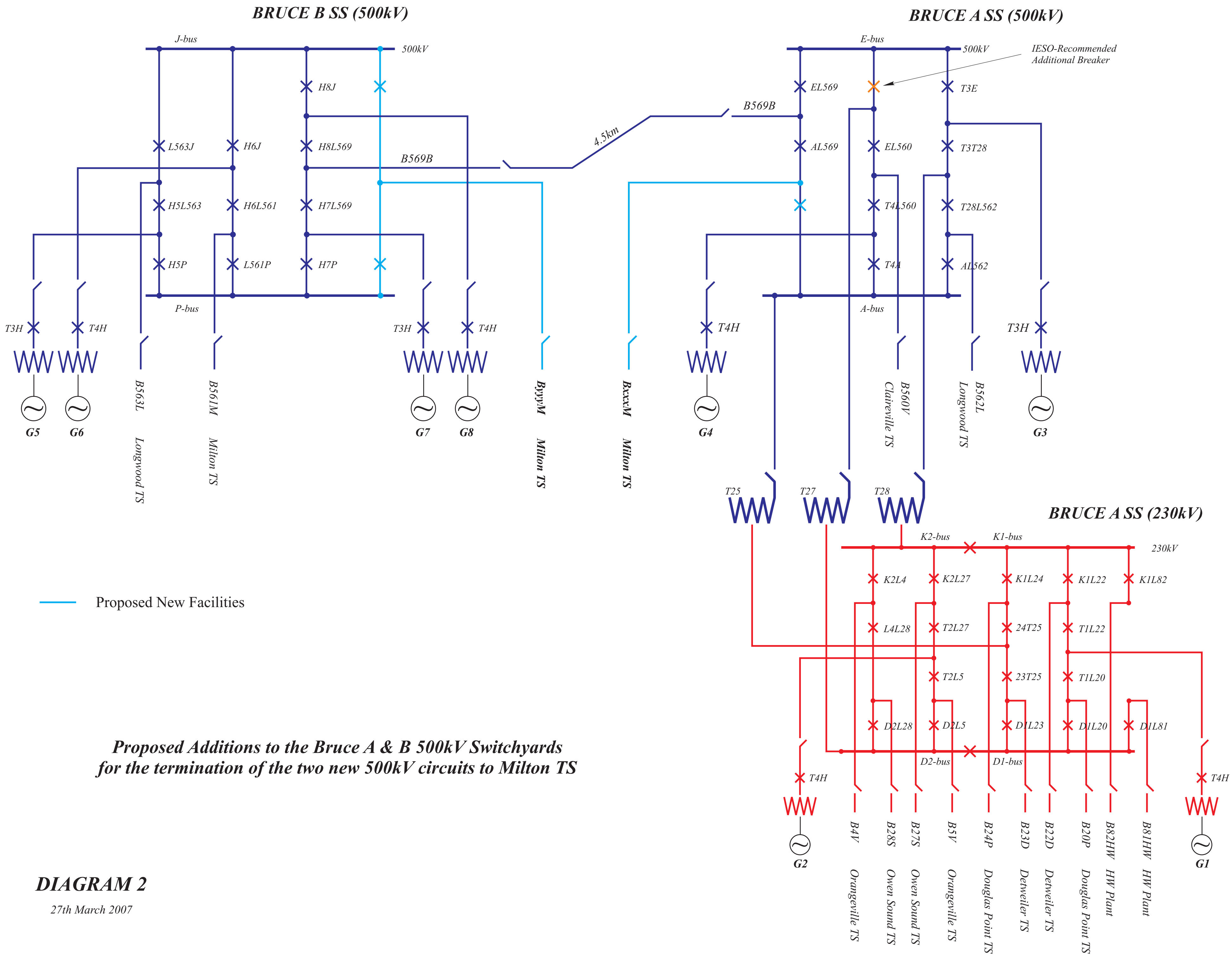


DIAGRAM 1

2nd February 2007

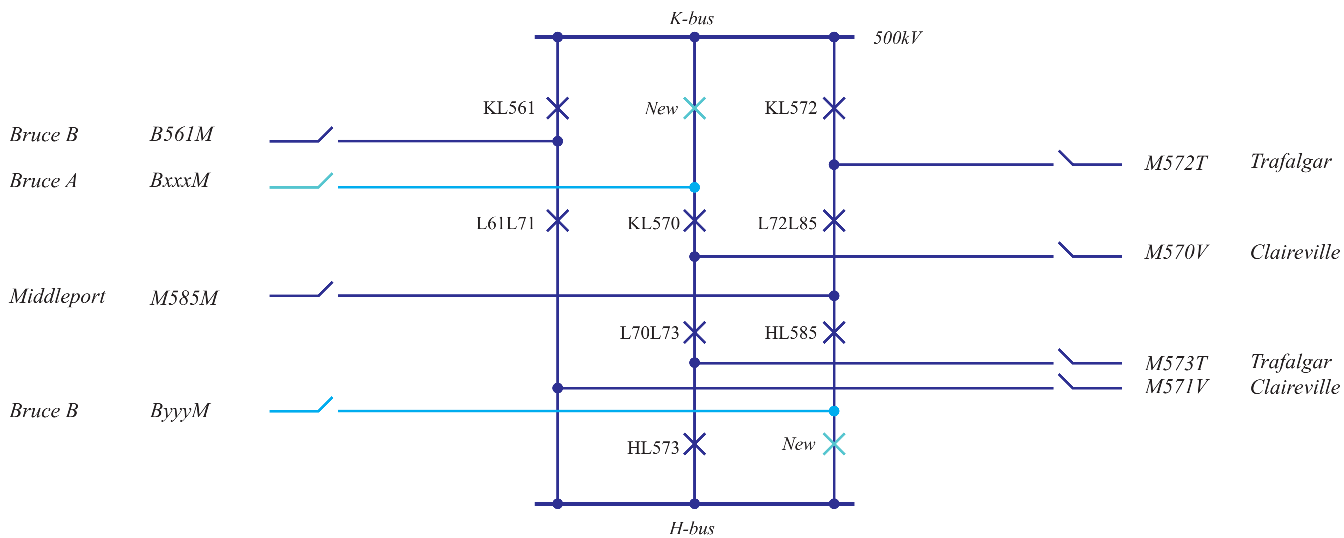


Proposed Additions to the Bruce A & B 500kV Switchyards for the termination of the two new 500kV circuits to Milton TS

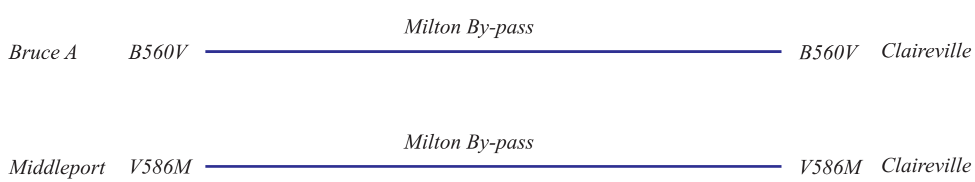
DIAGRAM 2

27th March 2007

MILTON TS (500kV)



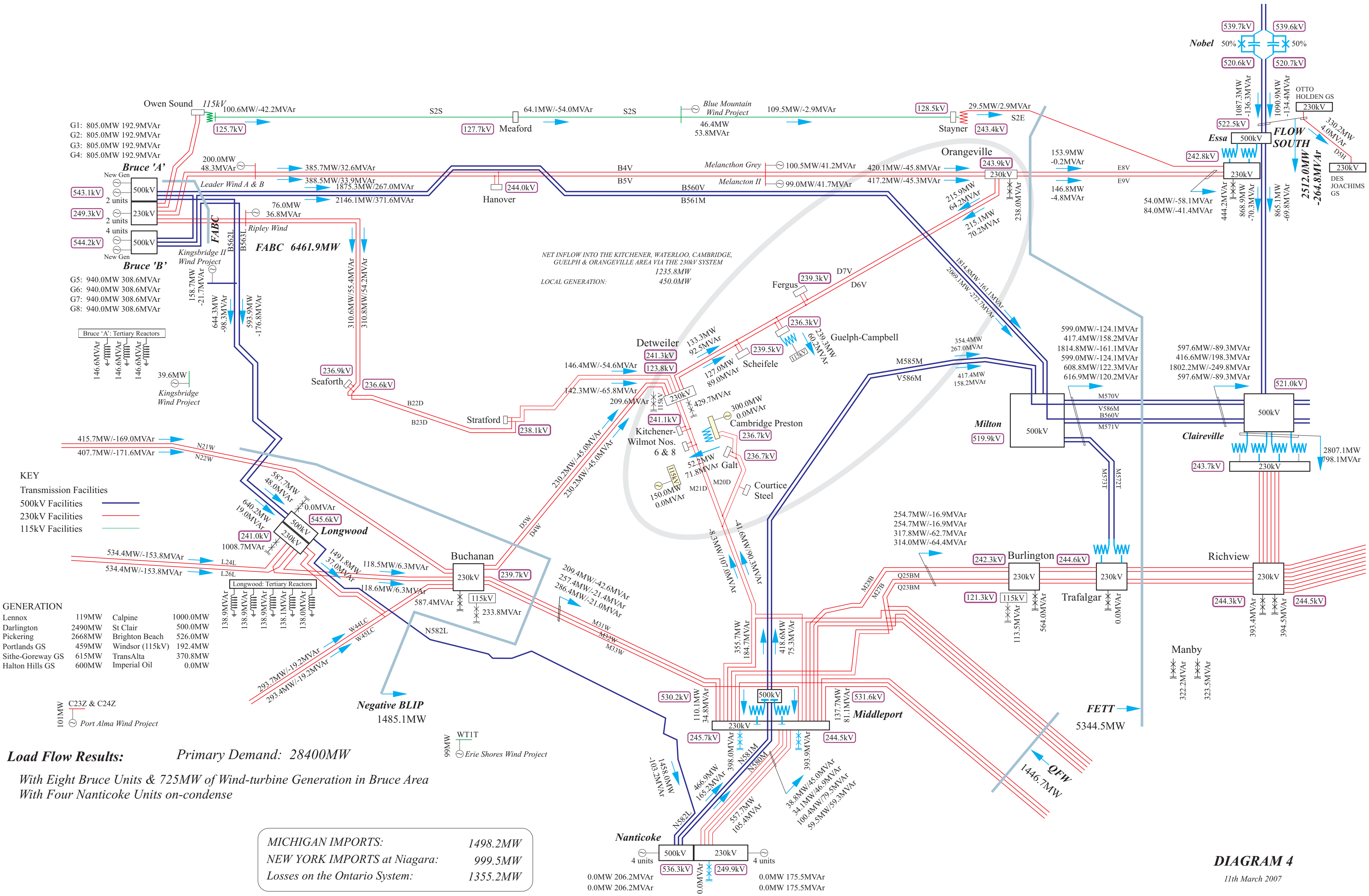
Proposed New Facilities



Proposed Additions to the Milton 500kV Switchyard for the termination of the two new 500kV circuits to the Bruce Complex

DIAGRAM 3

10th March 2007



Load Flow Results: *Primary Demand: 28400MW*

With Eight Bruce Units & 725MW of Wind-turbine Generation in Bruce Area
With Four Nanticoke Units on-condense

MICHIGAN IMPORTS:	*1498.2MW*
NEW YORK IMPORTS at Niagara:	*999.5MW*
Losses on the Ontario System:	*1355.2MW*

DIAGRAM 4

11th March 2007

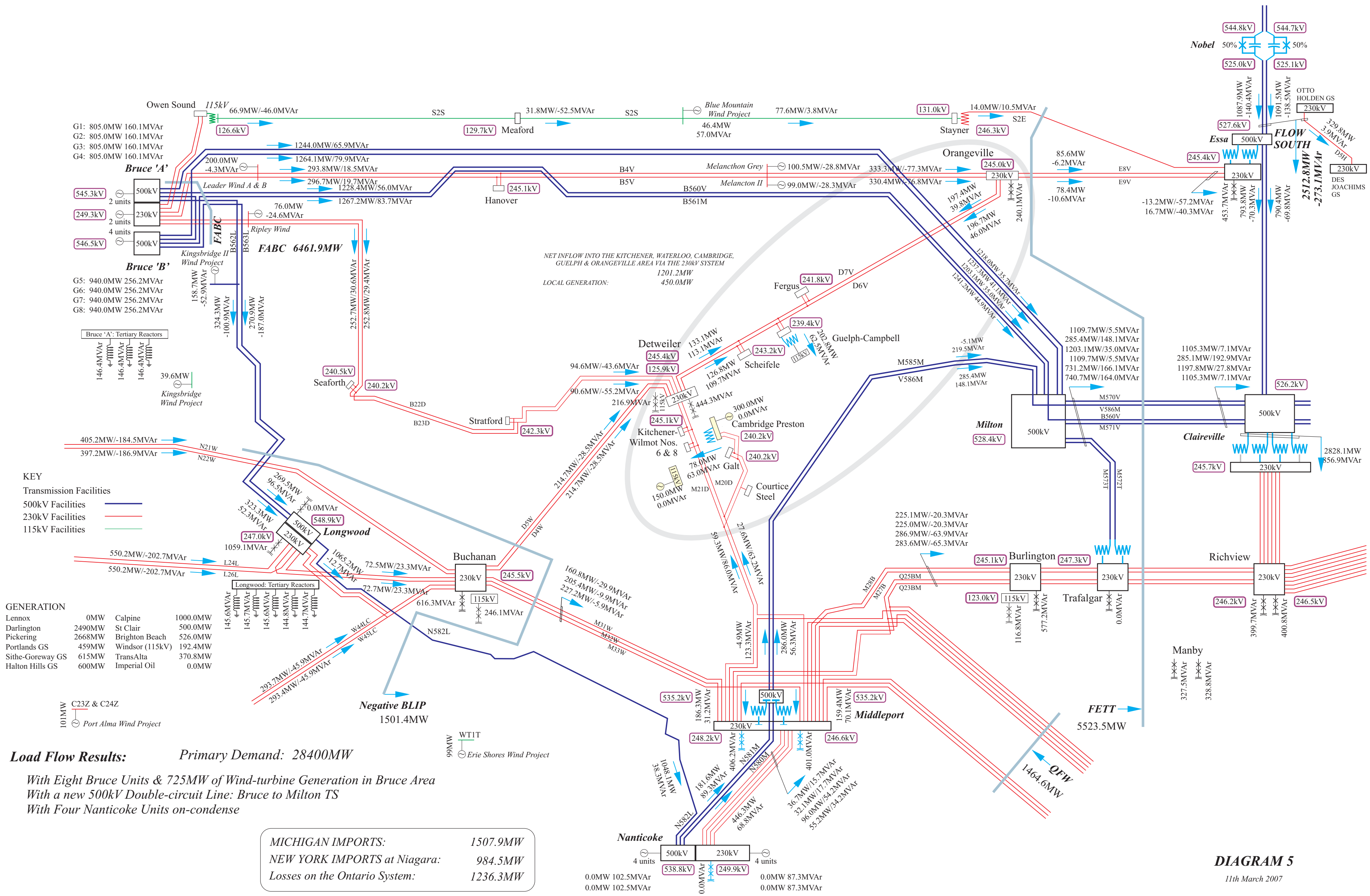
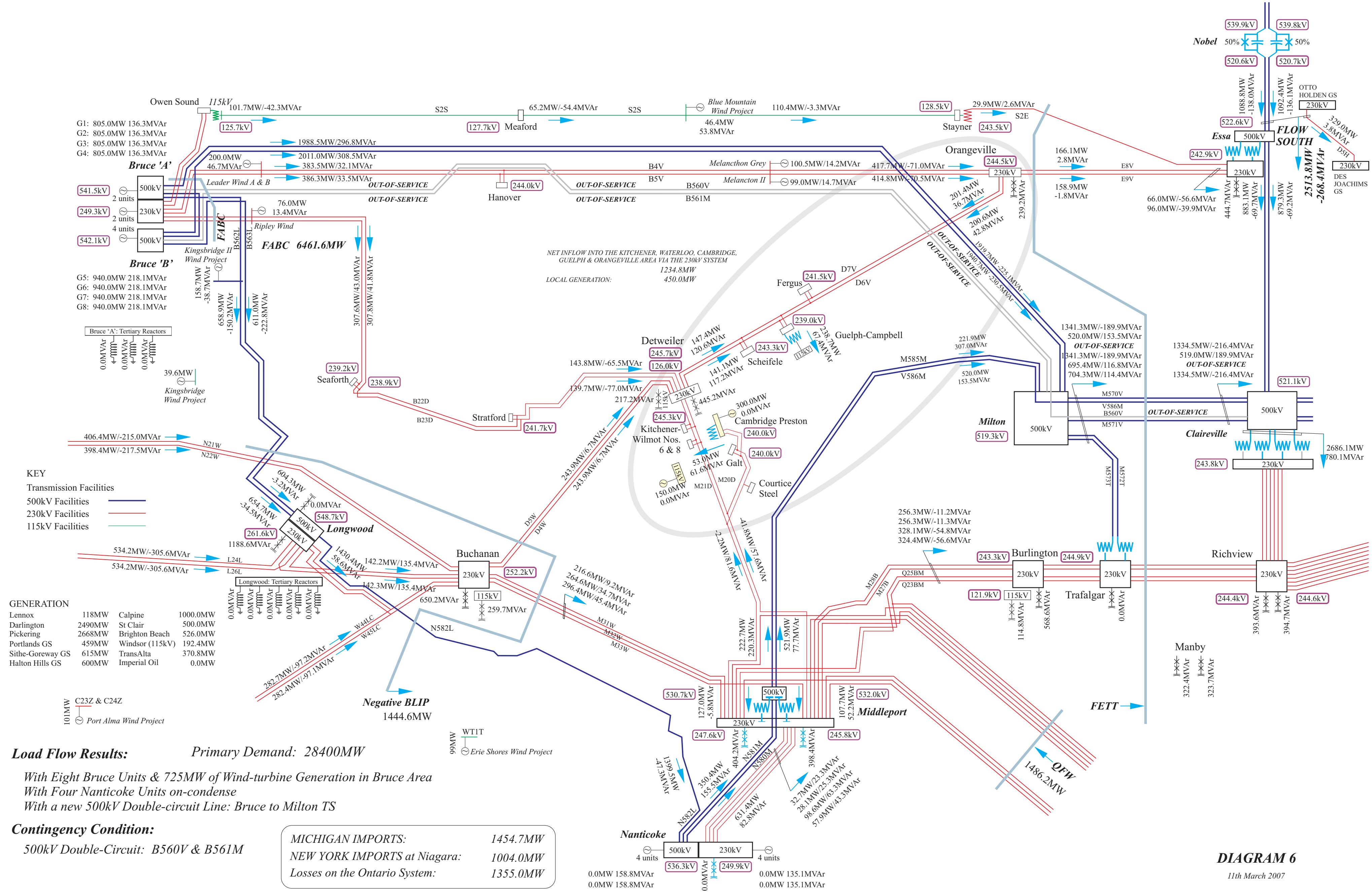
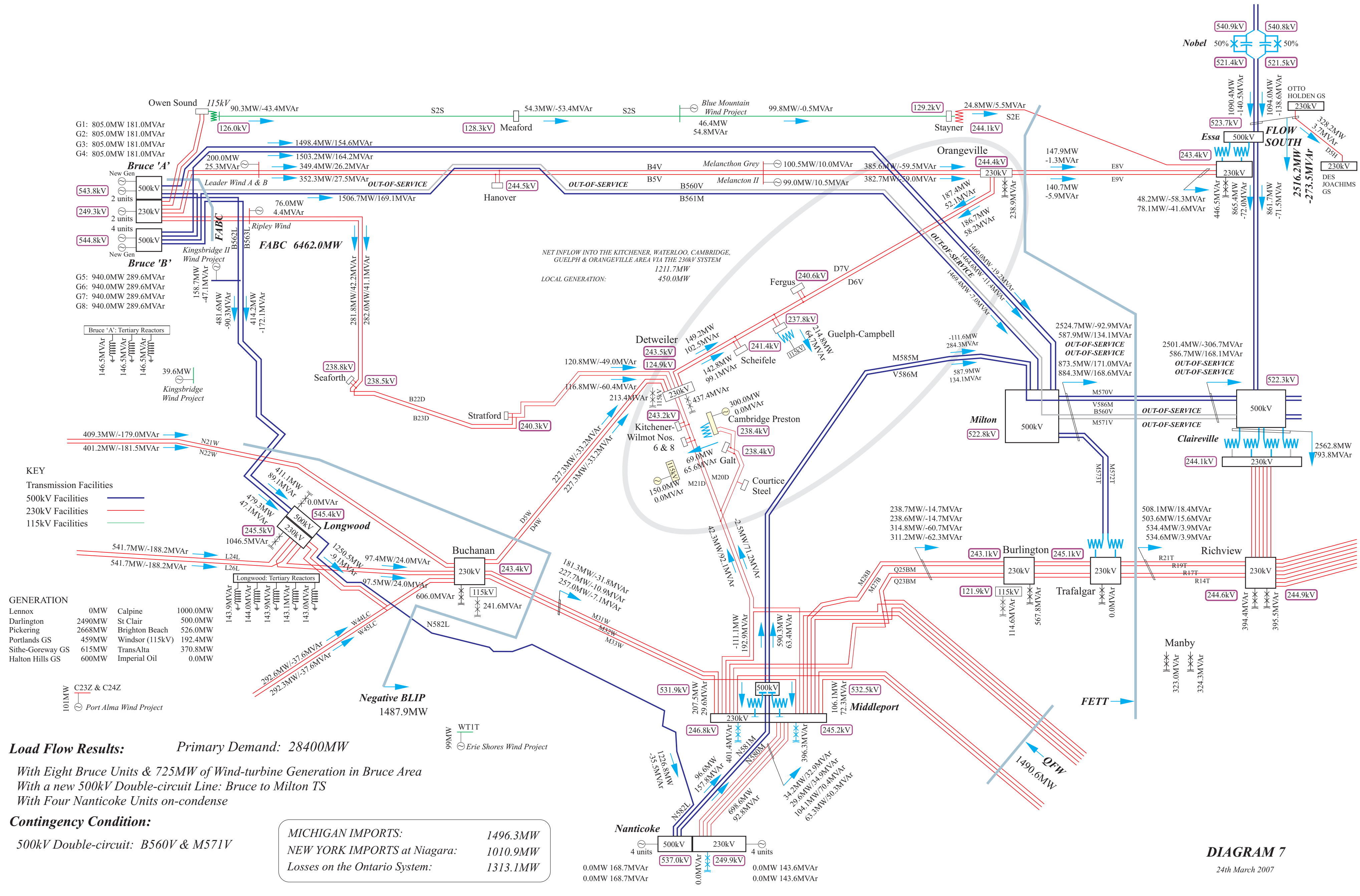


DIAGRAM 5

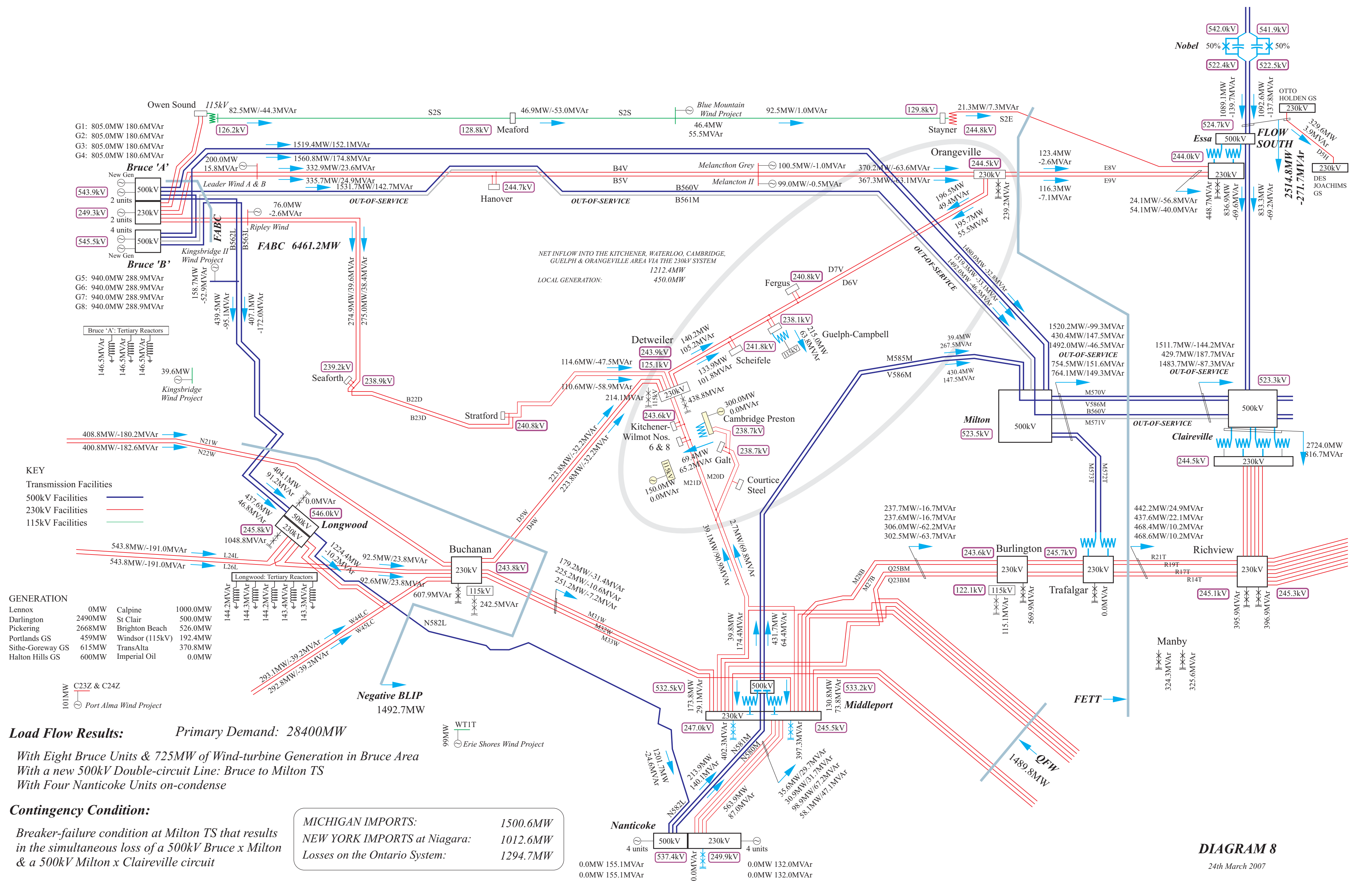
11th March 2007



Owen Sound
115kV
101.7MW/-42.3MVAr
125.7kV
S2S
65.2MW/-54.4MVAr
127.7kV
Meaford
Blue Mountain Wind Project
46.4MW
53.8MVAr
110.4MW/-3.3MVAr
128.5kV
Stayner
243.5kV
29.9MW/2.6MVAr
S2E
G1: 805.0MW 136.3MVAr
G2: 805.0MW 136.3MVAr
G3: 805.0MW 136.3MVAr
G4: 805.0MW 136.3MVAr
Bruce 'A'
1988.5MW/296.8MVAr
2011.0MW/308.5MVAr
200.0MW
46.7MVAr
383.5MW/32.1MVAr
386.3MW/33.5MVAr
Leader Wind A & B
OUT-OF-SERVICE
OUT-OF-SERVICE
Hanover
244.0kV
B4V
B5V
B560V
B561M
Melancthon Grey
100.5MW/14.2MVAr
Melancthon II
99.0MW/14.7MVAr
417.7MW/-71.0MVAr
414.8MW/-70.5MVAr
Orangeville
244.5kV
230kV
166.1MW
2.8MVAr
158.9MW
-1.8MVAr
E8V
E9V
541.5kV
249.3kV
542.1kV
2 units
4 units
500kV
230kV
76.0MW
13.4MVAr
Ripley Wind
FABC
FABC 6461.6MW
Kingsbridge II Wind Project
Bruce 'B'
G5: 940.0MW 218.1MVAr
G6: 940.0MW 218.1MVAr
G7: 940.0MW 218.1MVAr
G8: 940.0MW 218.1MVAr
B562L
B563L
158.7MW
-38.7MVAr
658.9MW
-150.2MVAr
611.0MW
-222.8MVAr
307.6MW/43.0MVAr
307.8MW/41.8MVAr
Bruce 'A': Tertiary Reactors
39.6MW
Kingsbridge Wind Project
NET INFLOW INTO THE KITCHENER, WATERLOO, CAMBRIDGE, GUELPH & ORANGEVILLE AREA VIA THE 230kV SYSTEM
1234.8MW
LOCAL GENERATION:
450.0MW
Nobel
539.9kV
539.8kV
520.6kV
520.7kV
50%
1088.8MW
-138.0MVAr
1092.4MW
-136.1MVAr
OTTO HOLDEN GS
522.6kV
Essa
FLOW SOUTH
2513.8MW
-268.4MVAr
329.0MW
3.8MVAr
D5H
DES JOACHIMS GS
242.9kV
66.0MW/-56.6MVAr
96.0MW/-39.9MVAr
444.7MVAr
883.1MW
-69.7MVAr
879.3MW
-69.2MVAr
201.4MW
36.7MVAr
200.6MW
42.8MVAr
239.2MVAr
1919.7MW -225.1MVAr
1940.7MW -230.5MVAr
Fergus
241.5kV
D7V
D6V
239.0kV
Guelph-Campbell
238.7MW
67.4MVAr
243.3kV
Scheifele
Detweiler
245.7kV
126.0kV
147.4MW
120.6MVAr
141.1MW
117.2MVAr
143.8MW/-65.5MVAr
139.7MW/-77.0MVAr
217.2MVAr
445.2MVAr
300.0MW
0.0MVAr
Cambridge Preston
240.0kV
245.3kV
Kitchener-Wilmot Nos. 6 & 8
240.0kV
Galt
53.0MW
61.6MVAr
150.0MW
0.0MVAr
M21D
M20D
Courtice Steel
239.2kV
Seaforth
238.9kV
B22D
B23D
Stratford
241.7kV
M585M
V586M
221.9MW
307.0MVAr
520.0MW
153.5MVAr
Milton
519.3kV
500kV
1341.3MW/-189.9MVAr
520.0MW/153.5MVAr
OUT-OF-SERVICE
1341.3MW/-189.9MVAr
695.4MW/116.8MVAr
704.3MW/114.4MVAr
1334.5MW/-216.4MVAr
519.0MW/189.9MVAr
OUT-OF-SERVICE
1334.5MW/-216.4MVAr
521.1kV
M570V
V586M
B560V
M571V
OUT-OF-SERVICE
Claireville
2686.1MW
780.1MVAr
243.8kV
M573T
M572T
406.4MW/-215.0MVAr
398.4MW/-217.5MVAr
N21W
N22W
604.3MW
-3.2MVAr
654.7MW
-34.5MVAr
0.0MVAr
548.7kV
Longwood
261.6kV
1188.6MVAr
534.2MW/-305.6MVAr
534.2MW/-305.6MVAr
L24L
L26L
Longwood: Tertiary Reactors
1430.4MW
58.6MVAr
142.2MW/135.4MVAr
142.3MW/135.4MVAr
650.2MVAr
Buchanan
252.2kV
115kV
259.7MVAr
D5W
D4W
243.9MW/6.7MVAr
243.9MW/6.7MVAr
216.6MW/9.2MVAr
264.6MW/34.7MVAr
296.4MW/45.4MVAr
M31W
M32W
M33W
W44LC
W45LC
282.7MW/-97.2MVAr
282.4MW/-97.1MVAr
N582L
Negative BLIP
1444.6MW
KEY
Transmission Facilities
500kV Facilities
230kV Facilities
115kV Facilities
GENERATION
Lennox 118MW
Darlington 2490MW
Pickering 2668MW
Portlands GS 459MW
Sithe-Goreway GS 615MW
Halton Hills GS 600MW
Calpine 1000.0MW
St Clair 500.0MW
Brighton Beach 526.0MW
Windsor (115kV) 192.4MW
TransAlta 370.8MW
Imperial Oil 0.0MW
101MW
C23Z & C24Z
Port Alma Wind Project
99MW
WT1T
Erie Shores Wind Project
-2.2MW/81.6MVAr
-41.8MW/57.6MVAr
256.3MW/-11.2MVAr
256.3MW/-11.3MVAr
328.1MW/-54.8MVAr
324.4MW/-56.6MVAr
243.3kV
Burlington
244.9kV
Q25BM
Q23BM
M28B
M27B
121.9kV
115kV
114.8MVAr
568.6MVAr
Trafalgar
0.0MVAr
Richview
244.4kV
244.6kV
393.6MVAr
394.7MVAr
Manby
322.4MVAr
323.7MVAr
222.7MW
220.3MVAr
521.9MW
77.7MVAr
530.7kV
127.0MW
-5.8MVAr
107.7MW
52.2MVAr
532.0kV
Middleport
247.6kV
245.8kV
404.2MVAr
398.4MVAr
N581M
N580M
FETT
QFW
1486.2MW
1399.5MW
-47.3MVAr
350.4MW
155.5MVAr
631.4MW
82.8MVAr
32.7MW/23.3MVAr
28.1MW/25.3MVAr
98.6MW/63.3MVAr
57.9MW/43.3MVAr
N582L
Nanticoke
536.3kV
249.9kV
0.0MVAr
0.0MW 158.8MVAr
0.0MW 158.8MVAr
0.0MW 135.1MVAr
0.0MW 135.1MVAr
Load Flow Results:
Primary Demand: 28400MW
With Eight Bruce Units & 725MW of Wind-turbine Generation in Bruce Area
With Four Nanticoke Units on-condense
With a new 500kV Double-circuit Line: Bruce to Milton TS
Contingency Condition:
500kV Double-Circuit: B560V & B561M
MICHIGAN IMPORTS: 1454.7MW
NEW YORK IMPORTS at Niagara: 1004.0MW
Losses on the Ontario System: 1355.0MW
DIAGRAM 6
11th March 2007



Load Flow Results:
Primary Demand: 28400MW
With Eight Bruce Units & 725MW of Wind-turbine Generation in Bruce Area
With a new 500kV Double-circuit Line: Bruce to Milton TS
With Four Nanticoke Units on-condense
Contingency Condition:
500kV Double-circuit: B560V & M571V
MICHIGAN IMPORTS: 1496.3MW
NEW YORK IMPORTS at Niagara: 1010.9MW
Losses on the Ontario System: 1313.1MW
DIAGRAM 7
24th March 2007
KEY
Transmission Facilities
500kV Facilities
230kV Facilities
115kV Facilities
GENERATION
Lennox 0MW
Darlington 2490MW
Pickering 2668MW
Portlands GS 459MW
Sithe-Goreway GS 615MW
Halton Hills GS 600MW
Calpine 1000.0MW
St Clair 500.0MW
Brighton Beach 526.0MW
Windsor (115kV) 192.4MW
TransAlta 370.8MW
Imperial Oil 0.0MW
G1: 805.0MW 181.0MVAr
G2: 805.0MW 181.0MVAr
G3: 805.0MW 181.0MVAr
G4: 805.0MW 181.0MVAr
Bruce 'A'
Bruce 'B'
G5: 940.0MW 289.6MVAr
G6: 940.0MW 289.6MVAr
G7: 940.0MW 289.6MVAr
G8: 940.0MW 289.6MVAr
FABC 6462.0MW
NET INFLOW INTO THE KITCHENER, WATERLOO, CAMBRIDGE, GUELPH & ORANGEVILLE AREA VIA THE 230kV SYSTEM 1211.7MW
LOCAL GENERATION: 450.0MW
FLOW SOUTH 2516.2MW -273.5MVAr
Negative BLIP 1487.9MW
QFW 1490.6MW
FETT
Owen Sound
Meaford
Stayner
Blue Mountain Wind Project
Nobel
Essa
OTTO HOLDEN GS
DES JOACHIMS GS
Orangeville
Hanover
Melancthon Grey
Melancton II
Leader Wind A & B
Ripley Wind
Kingsbridge II Wind Project
Kingsbridge Wind Project
Seaforth
Stratford
Detweiler
Fergus
Guelph-Campbell
Scheifele
Cambridge Preston
Kitchener-Wilmot Nos. 6 & 8
Galt
Courtice Steel
Milton
Claireville
Longwood
Buchanan
Burlington
Trafalgar
Richview
Manby
Middleport
Nanticoke
Port Alma Wind Project
Erie Shores Wind Project
Bruce 'A': Tertiary Reactors
Longwood: Tertiary Reactors
OUT-OF-SERVICE



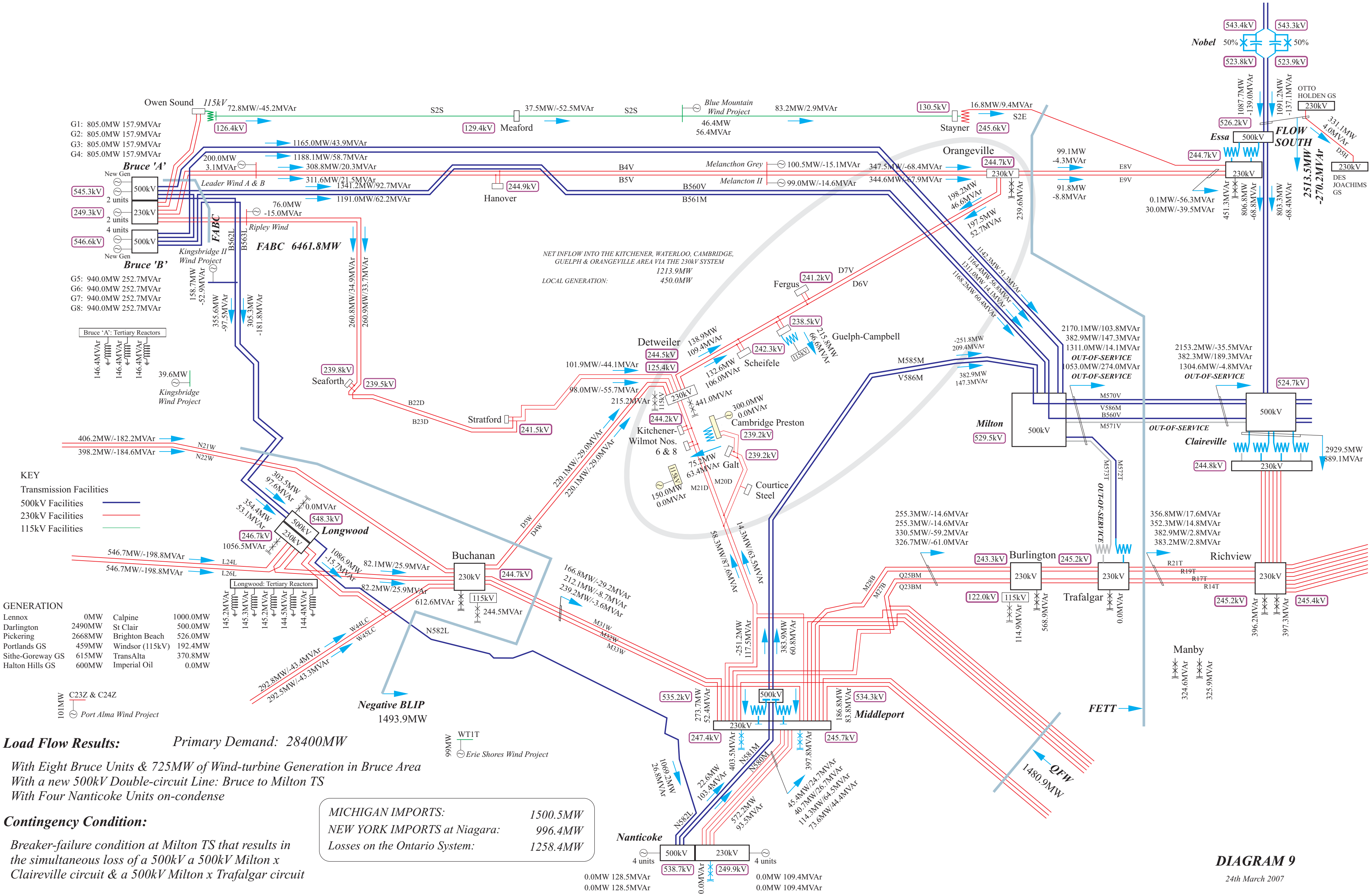
Load Flow Results: *Primary Demand: 28400MW*

With Eight Bruce Units & 725MW of Wind-turbine Generation in Bruce Area
With a new 500kV Double-circuit Line: Bruce to Milton TS
With Four Nanticoke Units on-condense

Contingency Condition:

Breaker-failure condition at Milton TS that results in the simultaneous loss of a 500kV Bruce x Milton & a 500kV Milton x Claireville circuit

MICHIGAN IMPORTS:	1500.6MW
NEW YORK IMPORTS at Niagara:	1012.6MW
Losses on the Ontario System:	1294.7MW



Load Flow Results: *Primary Demand: 28400MW*

With Eight Bruce Units & 725MW of Wind-turbine Generation in Bruce Area
With a new 500kV Double-circuit Line: Bruce to Milton TS
With Four Nanticoke Units on-condense

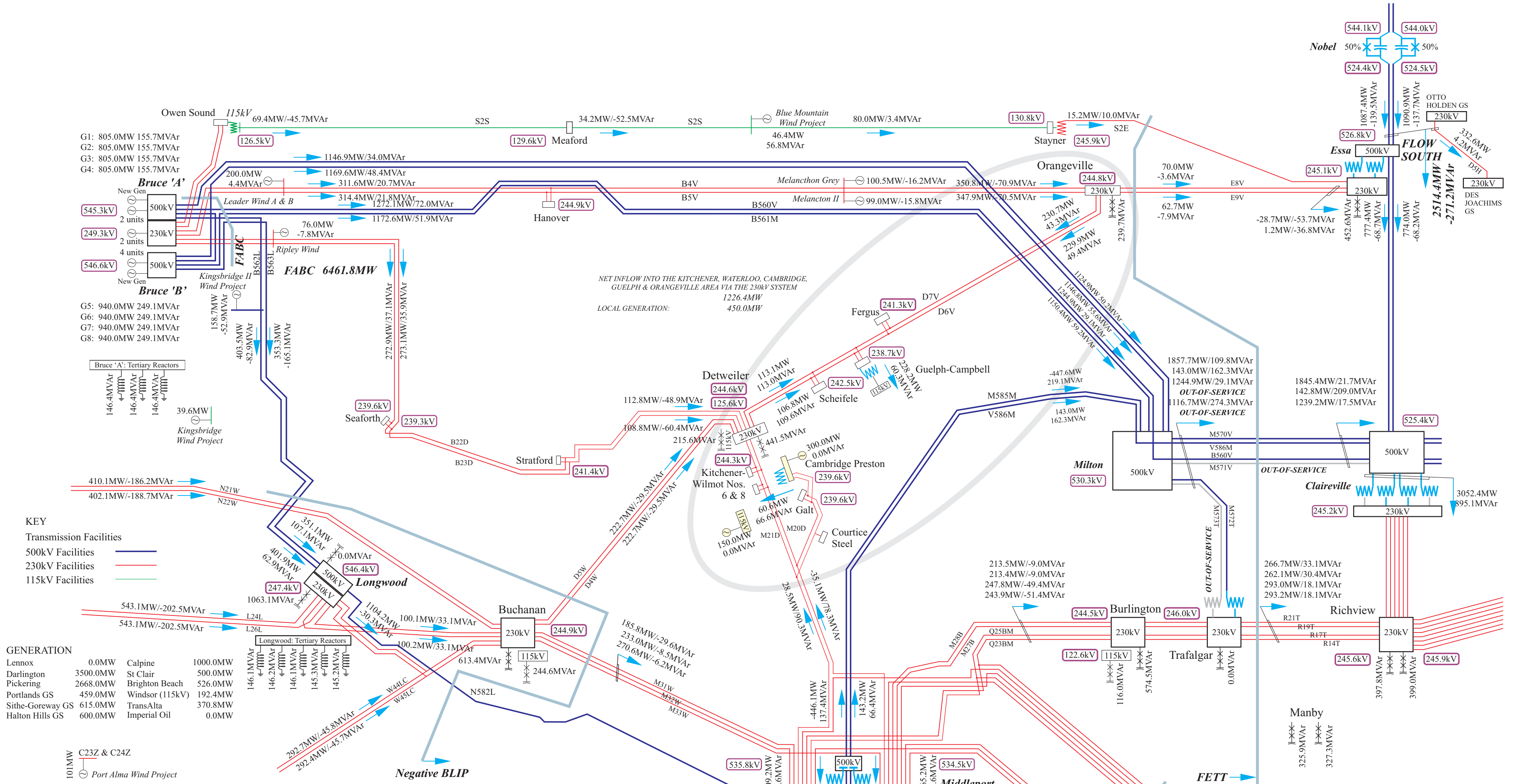
Contingency Condition:

Breaker-failure condition at Milton TS that results in the simultaneous loss of a 500kV a 500kV Milton x Claireville circuit & a 500kV Milton x Trafalgar circuit

MICHIGAN IMPORTS:	*1500.5MW*
NEW YORK IMPORTS at Niagara:	*996.4MW*
Losses on the Ontario System:	*1258.4MW*

DIAGRAM 9

24th March 2007



Load Flow Results:

Primary Demand: 28400MW

With Eight Bruce Units & 725MW of Wind-turbine Generation in Bruce Area
With a new 500kV Double-circuit Line: Bruce to Milton TS
With Four Nanticoke Units on-condense
With a reduced QFW transfer

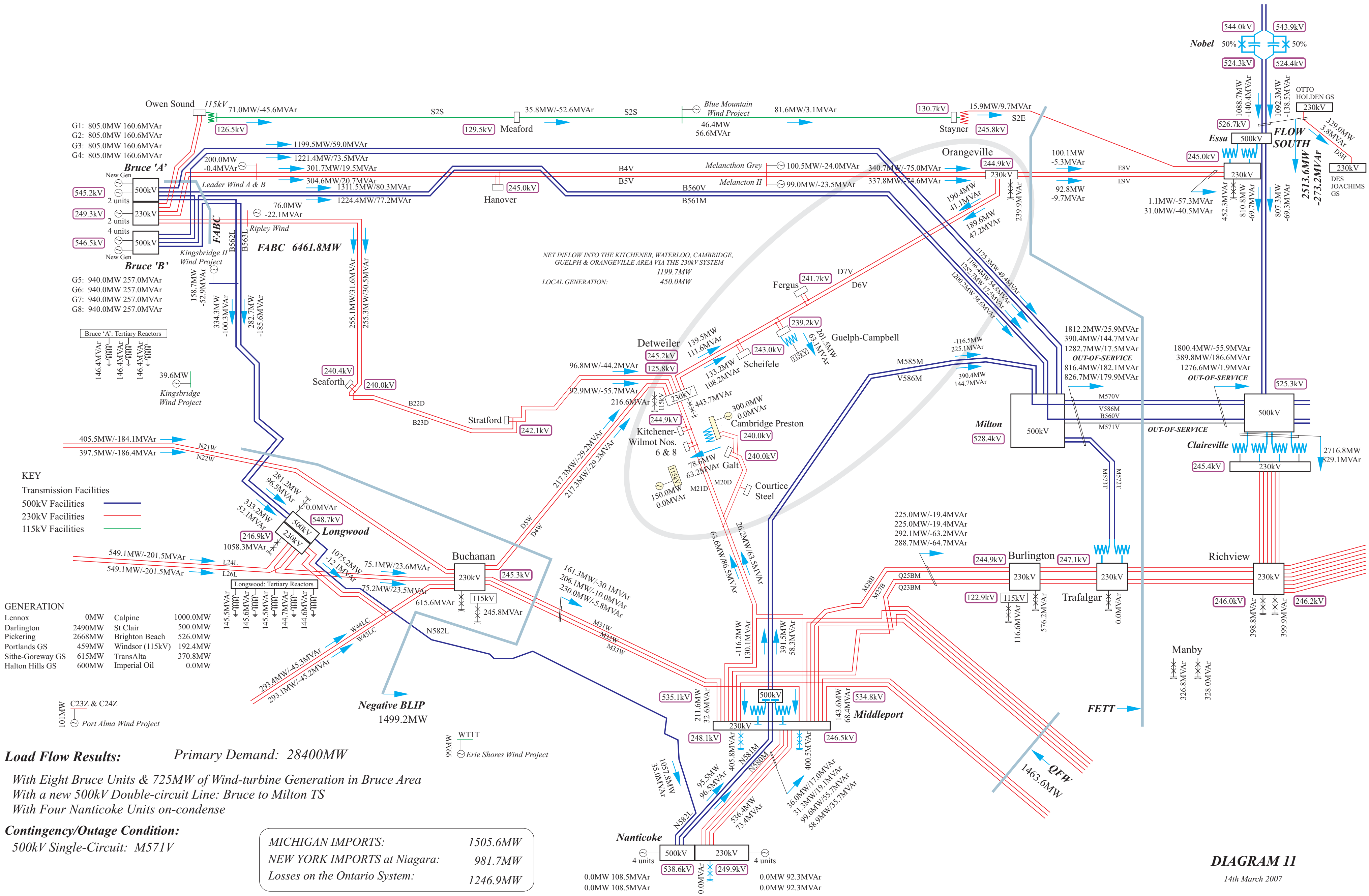
Contingency Condition:

Breaker-failure condition at Milton TS that results in the simultaneous loss of a 500kV a 500kV Milton x Claireville circuit & a 500kV Milton x Trafalgar circuit

MICHIGAN IMPORTS:	*1501.5MW*
NEW YORK IMPORTS at Niagara:	*-4.3MW*
Losses on the Ontario System:	*1223.8MW*

DIAGRAM 10

26th March 2007



Load Flow Results: *Primary Demand: 28400MW*

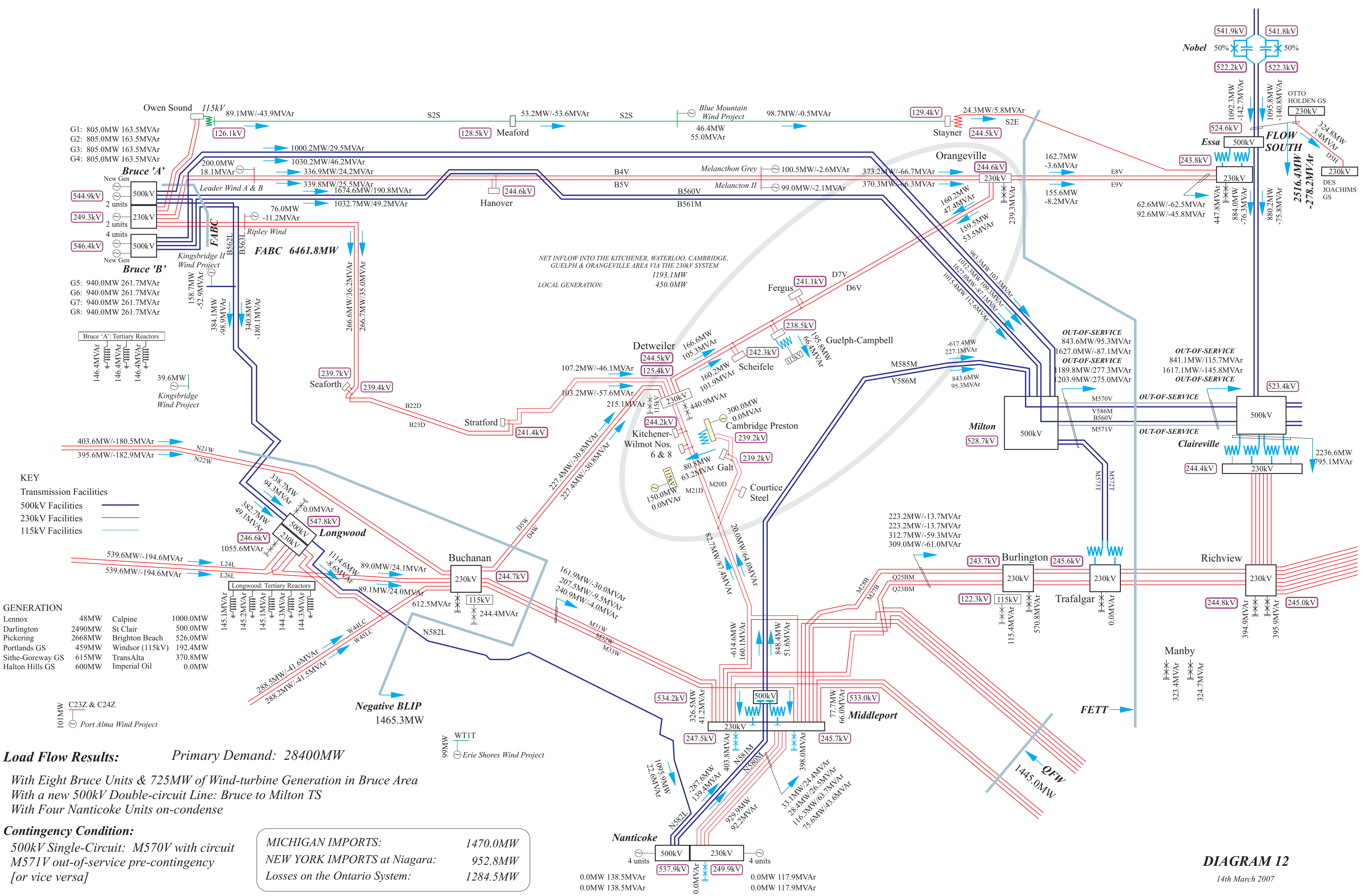
With Eight Bruce Units & 725MW of Wind-turbine Generation in Bruce Area
With a new 500kV Double-circuit Line: Bruce to Milton TS
With Four Nanticoke Units on-condense

Contingency/Outage Condition:
500kV Single-Circuit: M571V

MICHIGAN IMPORTS:	1505.6MW
NEW YORK IMPORTS at Niagara:	981.7MW
Losses on the Ontario System:	1246.9MW

DIAGRAM 11

14th March 2007



GENERATION

Lennox	48MW	Calpine	1000.0MW
Darlington	2490MW	St Clair	500.0MW
Pickering	2668MW	Brighton Beach	526.0MW
Portlands GS	459MW	Windsor (115kV)	192.4MW
Sithe-Goreway GS	615MW	TransAlta	370.8MW
Halton Hills GS	600MW	Imperial Oil	0.0MW

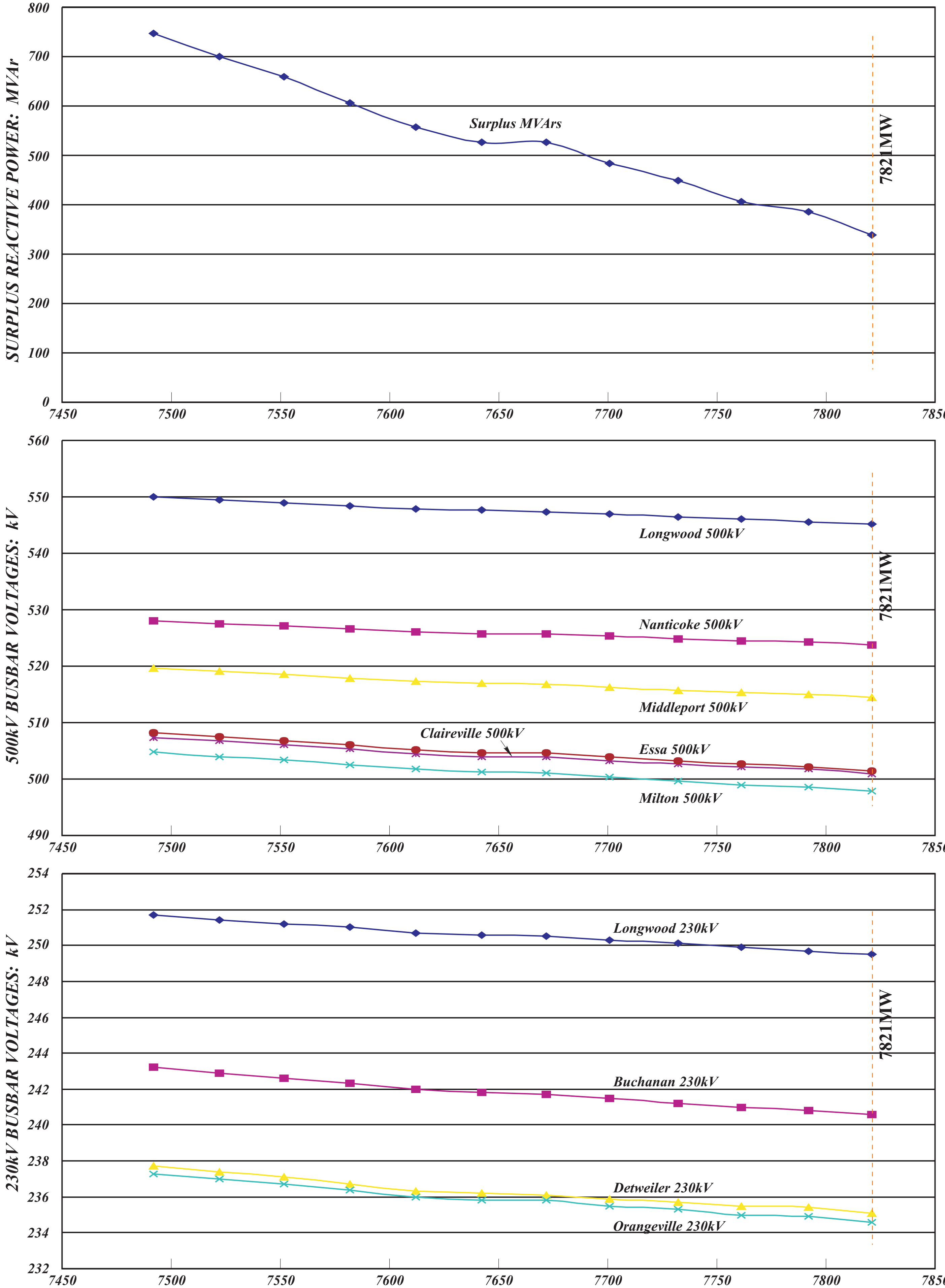
Load Flow Results: *Primary Demand: 28400MW*

With Eight Bruce Units & 725MW of Wind-turbine Generation in Bruce Area
With a new 500kV Double-circuit Line: Bruce to Milton TS
With Four Nanticoke Units on-condense

Contingency Condition:

500kV Single-Circuit: M570V with circuit M571V out-of-service pre-contingency [or vice versa]

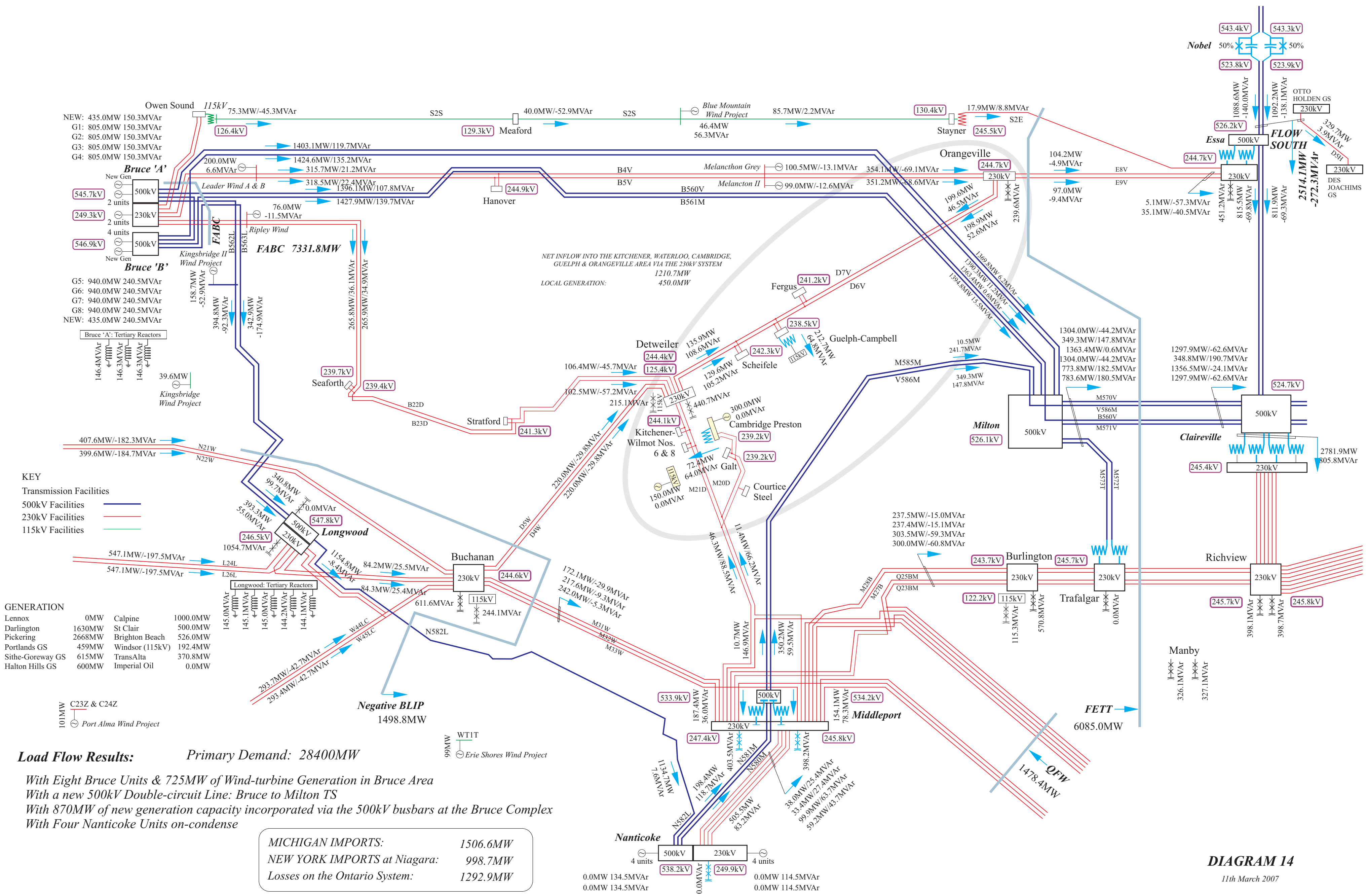
MICHIGAN IMPORTS:	1470.0MW
NEW YORK IMPORTS at Niagara:	952.8MW
Losses on the Ontario System:	1284.5MW



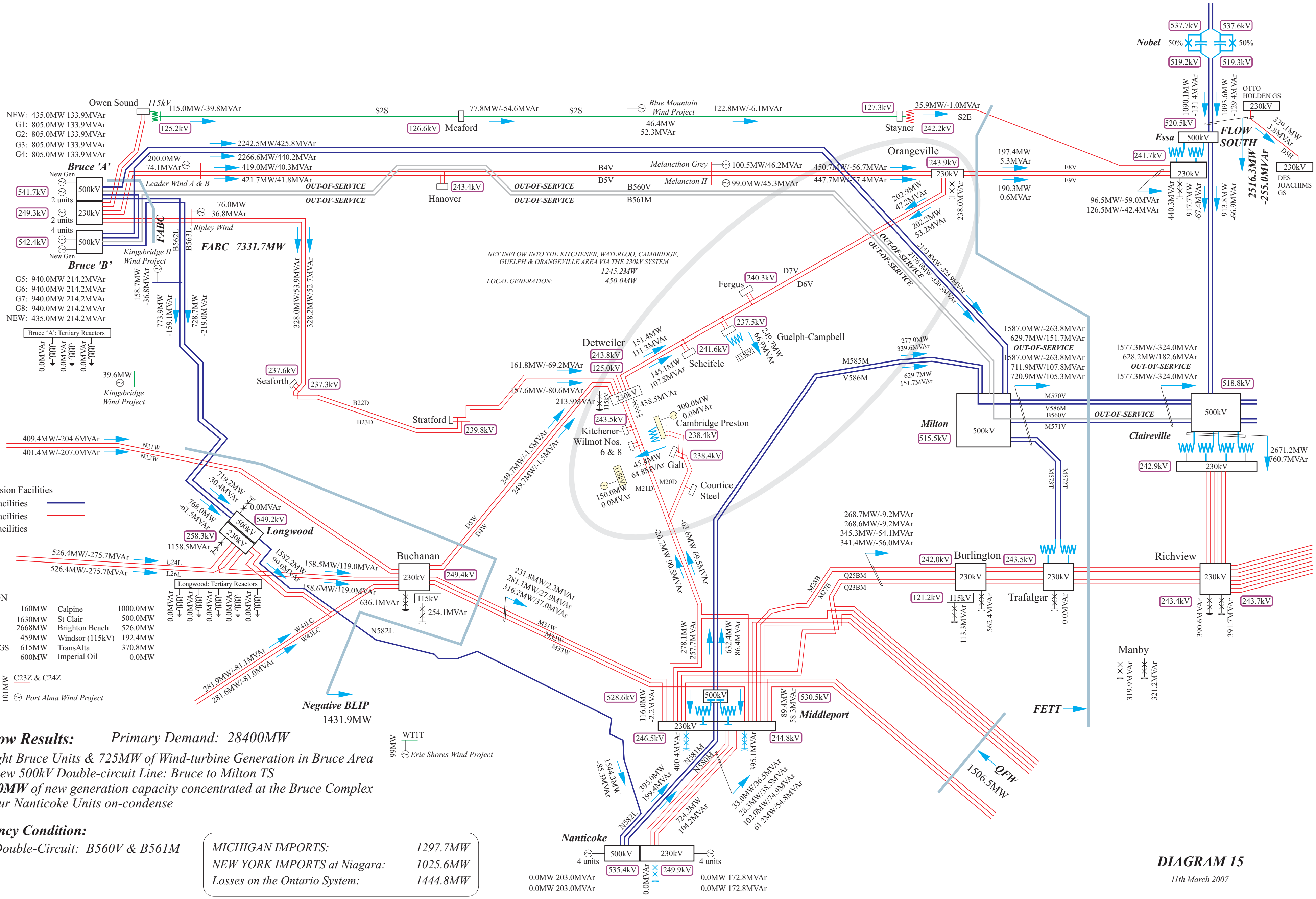
PV-Curves for the arrangement with a new 500kV line to Milton TS

DIAGRAM 13

11th March 2007



Load Flow Results:
Primary Demand: 28400MW
With Eight Bruce Units & 725MW of Wind-turbine Generation in Bruce Area
With a new 500kV Double-circuit Line: Bruce to Milton TS
With 870MW of new generation capacity incorporated via the 500kV busbars at the Bruce Complex
With Four Nanticoke Units on-condense
MICHIGAN IMPORTS: 1506.6MW
NEW YORK IMPORTS at Niagara: 998.7MW
Losses on the Ontario System: 1292.9MW
DIAGRAM 14
11th March 2007
KEY
Transmission Facilities
500kV Facilities
230kV Facilities
115kV Facilities
GENERATION
Lennox 0MW
Darlington 1630MW
Pickering 2668MW
Portlands GS 459MW
Sithe-Goreway GS 615MW
Halton Hills GS 600MW
Calpine 1000.0MW
St Clair 500.0MW
Brighton Beach 526.0MW
Windsor (115kV) 192.4MW
TransAlta 370.8MW
Imperial Oil 0.0MW
NEW: 435.0MW 150.3MVAr
G1: 805.0MW 150.3MVAr
G2: 805.0MW 150.3MVAr
G3: 805.0MW 150.3MVAr
G4: 805.0MW 150.3MVAr
Bruce 'A'
Bruce 'B'
G5: 940.0MW 240.5MVAr
G6: 940.0MW 240.5MVAr
G7: 940.0MW 240.5MVAr
G8: 940.0MW 240.5MVAr
NEW: 435.0MW 240.5MVAr
Bruce 'A': Tertiary Reactors
FABC 7331.8MW
NET INFLOW INTO THE KITCHENER, WATERLOO, CAMBRIDGE, GUELPH & ORANGEVILLE AREA VIA THE 230kV SYSTEM 1210.7MW
LOCAL GENERATION: 450.0MW
Negative BLIP 1498.8MW
FETT 6085.0MW
QFW 1478.4MW
FLOW SOUTH 2514.1MW -272.3MVAr
Owen Sound
Meaford
Stayner
Blue Mountain Wind Project
Hanover
Orangeville
Essa
Nobel
OTTO HOLDEN GS
DES JOACHIMS GS
Melancthon Grey
Melancthon II
Leader Wind A & B
Ripley Wind
Kingsbridge II Wind Project
Kingsbridge Wind Project
Seaforth
Stratford
Detweiler
Fergus
Guelph-Campbell
Scheifele
Cambridge Preston
Kitchener-Wilmot Nos. 6 & 8
Galt
Courtice Steel
Milton
Claireville
Longwood
Longwood: Tertiary Reactors
Buchanan
Burlington
Trafalgar
Richview
Manby
Middleport
Nanticoke
Port Alma Wind Project
Erie Shores Wind Project



Load Flow Results: *Primary Demand: 28400MW*

With Eight Bruce Units & 725MW of Wind-turbine Generation in Bruce Area
With a new 500kV Double-circuit Line: Bruce to Milton TS
*With **870MW** of new generation capacity concentrated at the Bruce Complex*
With Four Nanticoke Units on-condense

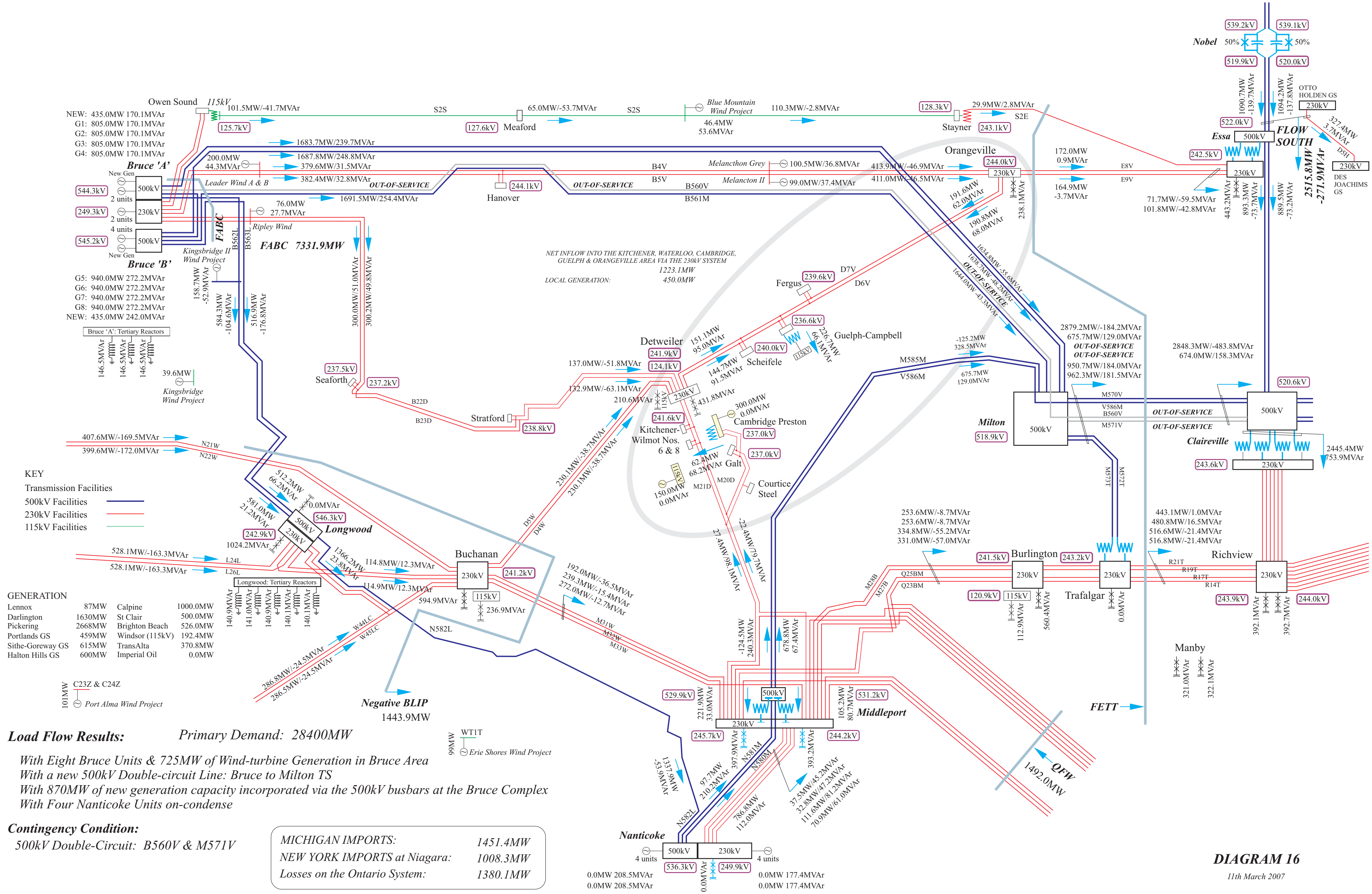
Contingency Condition:

500kV Double-Circuit: B560V & B561M

MICHIGAN IMPORTS:	*1297.7MW*
NEW YORK IMPORTS at Niagara:	*1025.6MW*
Losses on the Ontario System:	*1444.8MW*

DIAGRAM 15

11th March 2007



Load Flow Results: Primary Demand: 28400MW

With Eight Bruce Units & 725MW of Wind-turbine Generation in Bruce Area
With a new 500kV Double-circuit Line: Bruce to Milton TS
With 870MW of new generation capacity incorporated via the 500kV busbars at the Bruce Complex
With Four Nanticoke Units on-condense

Contingency Condition:

500kV Double-Circuit: B560V & M571V

MICHIGAN IMPORTS:	1451.4MW
NEW YORK IMPORTS at Niagara:	1008.3MW
Losses on the Ontario System:	1380.1MW

DIAGRAM 16

11th March 2007

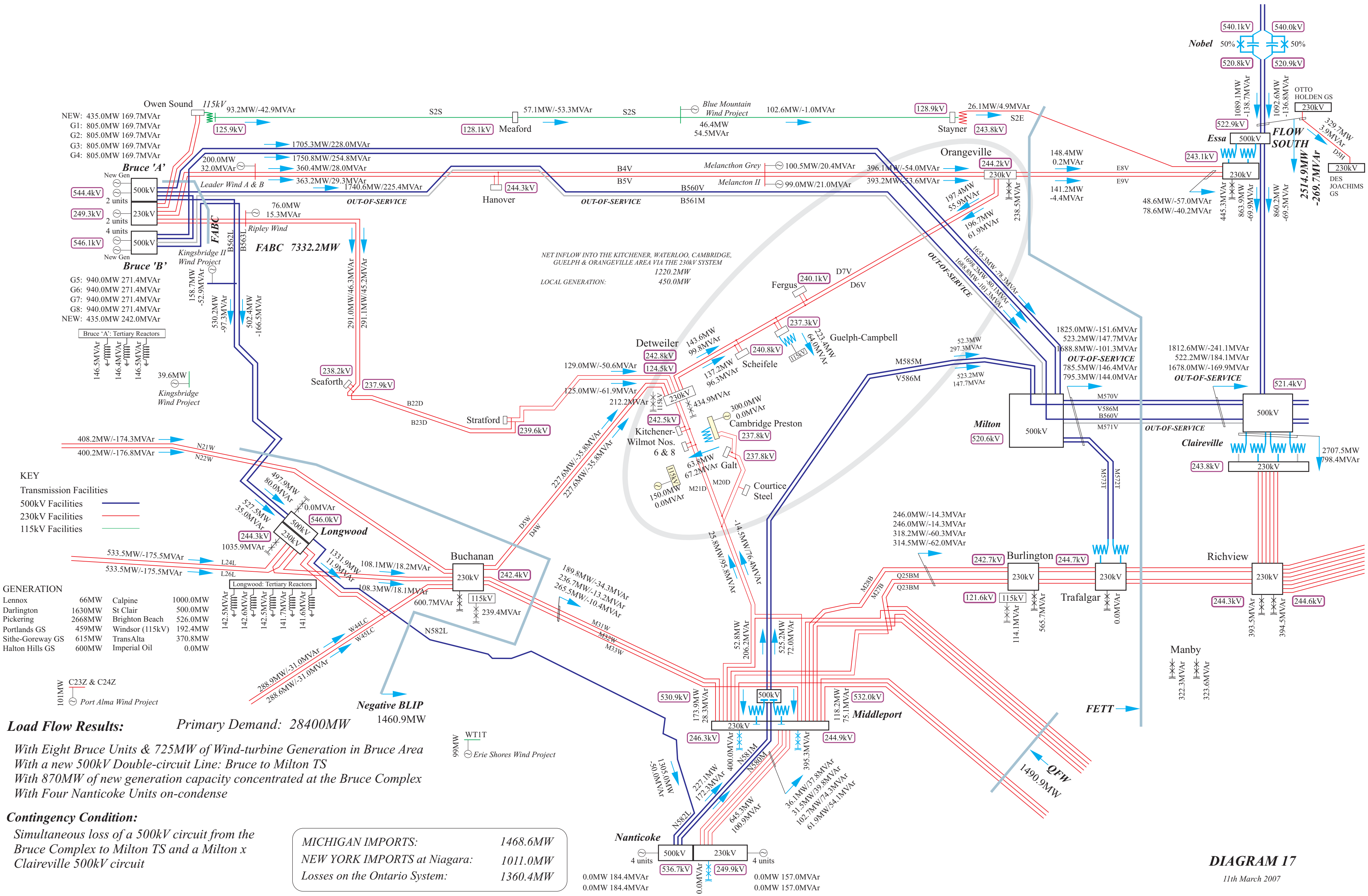
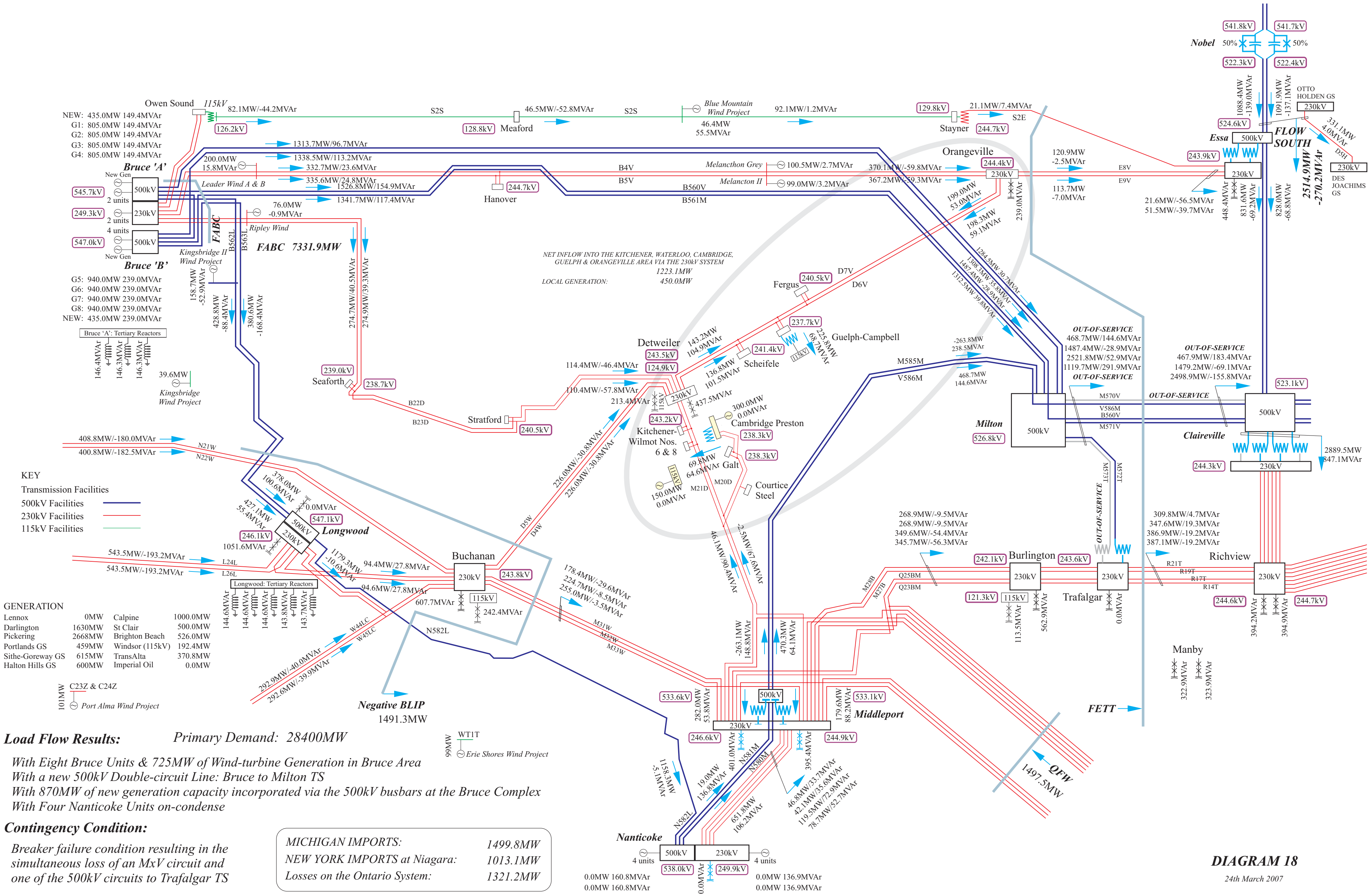
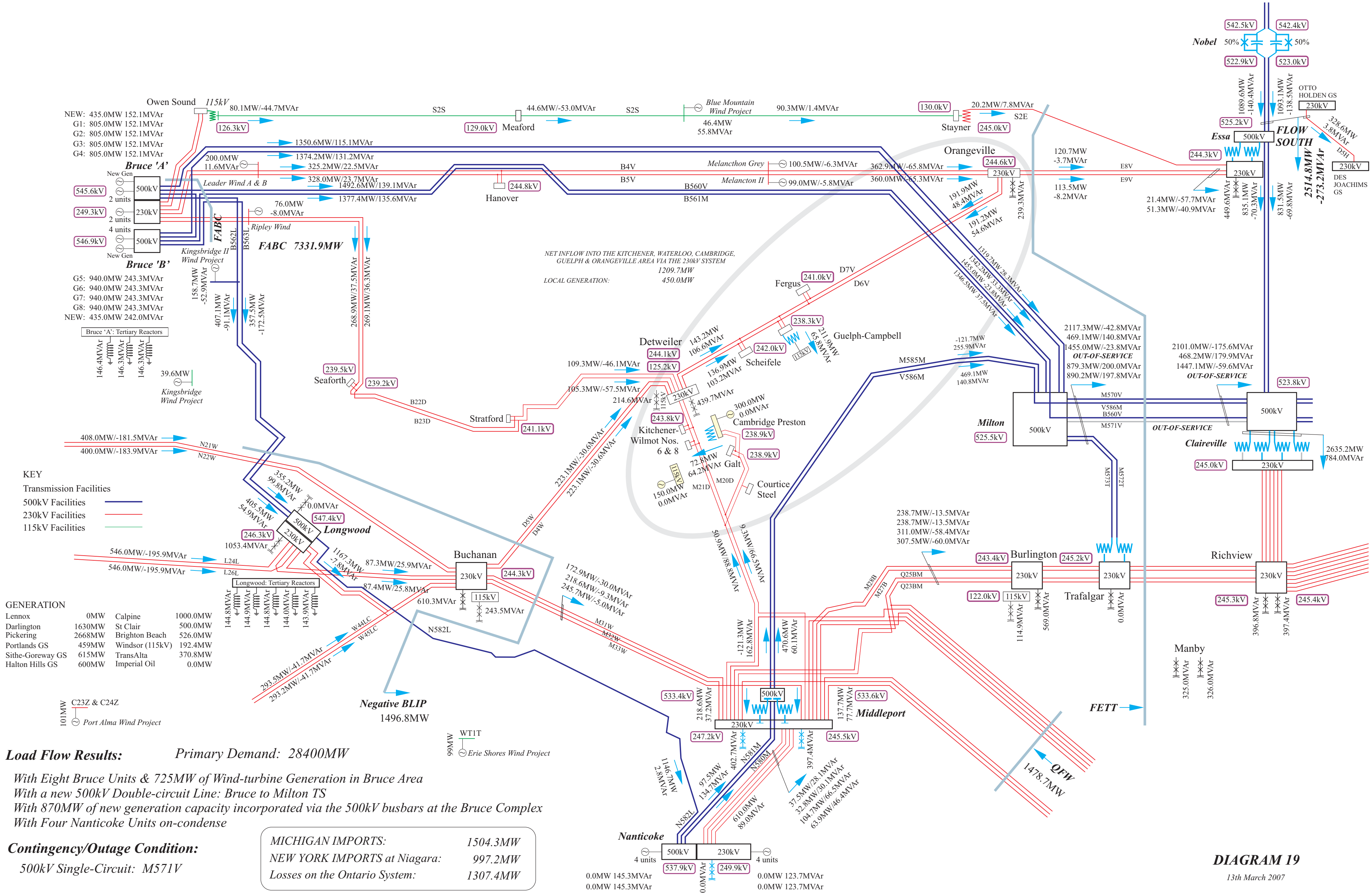


DIAGRAM 17
11th March 2007



Owen Sound
115kV
82.1MW/-44.2MVAr
126.2kV
S2S
46.5MW/-52.8MVAr
128.8kV
Meaford
S2S
Blue Mountain Wind Project
46.4MW 55.5MVAr
92.1MW/1.2MVAr
129.8kV
21.1MW/7.4MVAr
S2E
Stayner
244.7kV
NEW: 435.0MW 149.4MVAr
G1: 805.0MW 149.4MVAr
G2: 805.0MW 149.4MVAr
G3: 805.0MW 149.4MVAr
G4: 805.0MW 149.4MVAr
Bruce 'A'
New Gen
545.7kV
500kV
2 units
249.3kV
230kV
2 units
4 units
547.0kV
500kV
New Gen
Bruce 'B'
G5: 940.0MW 239.0MVAr
G6: 940.0MW 239.0MVAr
G7: 940.0MW 239.0MVAr
G8: 940.0MW 239.0MVAr
NEW: 435.0MW 239.0MVAr
Bruce 'A': Tertiary Reactors
146.4MVAr
146.3MVAr
146.3MVAr
1313.7MW/96.7MVAr
1338.5MW/113.2MVAr
200.0MW 15.8MVAr
332.7MW/23.6MVAr
335.6MW/24.8MVAr
1526.8MW/154.9MVAr
Leader Wind A & B
1341.7MW/117.4MVAr
76.0MW -0.9MVAr
Ripley Wind
FABC
FABC 7331.9MW
B562L
B563L
Kingsbridge II Wind Project
158.7MW -52.9MVAr
428.8MW -88.4MVAr
380.6MW -168.4MVAr
274.7MW/40.5MVAr
274.9MW/39.3MVAr
39.6MW
Kingsbridge Wind Project
244.7kV
Hanover
B4V
B5V
B560V
B561M
Melancthon Grey
100.5MW/2.7MVAr
Melancton II
99.0MW/3.2MVAr
Orangeville
370.1MW/-59.8MVAr
367.2MW/-59.3MVAr
244.4kV
230kV
199.0MW 53.0MVAr
198.3MW 59.1MVAr
239.0MVAr
120.9MW -2.5MVAr
113.7MW -7.0MVAr
E8V
E9V
21.6MW/-56.5MVAr
51.5MW/-39.7MVAr
541.8kV
541.7kV
Nobel
50%
50%
522.3kV
522.4kV
1088.4MW -139.0MVAr
1091.9MW -137.1MVAr
OTTO HOLDEN GS
230kV
331.1MW 4.0MVAr
D5H
230kV
DES JOACHIMS GS
524.6kV
Essa
500kV
FLOW SOUTH
2514.9MW -270.2MVAr
243.9kV
230kV
448.4MVAr
831.6MW -69.2MVAr
828.0MW -68.8MVAr
NET INFLOW INTO THE KITCHENER, WATERLOO, CAMBRIDGE, GUELPH & ORANGEVILLE AREA VIA THE 230kV SYSTEM
1223.1MW
LOCAL GENERATION: 450.0MW
Fergus
240.5kV
D7V
D6V
237.7kV
Guelph-Campbell
225.8MW 68.7MVAr
115kV
Detweiler
243.5kV
124.9kV
143.2MW 104.9MVAr
241.4kV
Scheifele
136.8MW 101.5MVAr
114.4MW/-46.4MVAr
110.4MW/-57.8MVAr
213.4MVAr
230kV
115kV
437.5MVAr
300.0MW 0.0MVAr
Cambridge Preston
238.3kV
Kitchener-Wilmot Nos. 6 & 8
243.2kV
238.3kV
Galt
69.8MW 64.6MVAr
150.0MW 0.0MVAr
115kV
M21D
M20D
Courtice Steel
239.0kV
Seaforth
238.7kV
B22D
B23D
Stratford
240.5kV
226.0MW/-30.8MVAr
226.0MW/-30.8MVAr
D5W
D4W
1284.5MW 30.7MVAr
1308.3MW 35.8MVAr
1487.4MW -28.9MVAr
1312.5MW 39.8MVAr
-263.8MW 238.5MVAr
M585M
V586M
468.7MW 144.6MVAr
OUT-OF-SERVICE
468.7MW/144.6MVAr
1487.4MW/-28.9MVAr
2521.8MW/52.9MVAr
1119.7MW/291.9MVAr
OUT-OF-SERVICE
OUT-OF-SERVICE
467.9MW/183.4MVAr
1479.2MW/-69.1MVAr
2498.9MW/-155.8MVAr
523.1kV
M570V
OUT-OF-SERVICE
V586M
B560V
M571V
Milton
500kV
526.8kV
500kV
Claireville
2889.5MW 347.1MVAr
244.3kV
230kV
M573T
M572T
OUT-OF-SERVICE
408.8MW/-180.0MVAr
400.8MW/-182.5MVAr
N21W
N22W
378.0MW 100.6MVAr
427.1MW 55.4MVAr
0.0MVAr
547.1kV
500kV
230kV
Longwood
246.1kV
1051.6MVAr
543.5MW/-193.2MVAr
543.5MW/-193.2MVAr
L24L
L26L
1179.3MW -10.6MVAr
94.4MW/27.8MVAr
94.6MW/27.8MVAr
Longwood: Tertiary Reactors
144.6MVAr
144.6MVAr
144.6MVAr
143.8MVAr
143.7MVAr
Buchanan
230kV
243.8kV
115kV
607.7MVAr
242.4MVAr
N582L
178.4MW/-29.6MVAr
224.7MW/-8.5MVAr
255.0MW/-3.5MVAr
M31W
M32W
M33W
W44LC
W45LC
292.9MW/-40.0MVAr
292.6MW/-39.9MVAr
Negative BLIP
1491.3MW
KEY
Transmission Facilities
500kV Facilities
230kV Facilities
115kV Facilities
GENERATION
Lennox 0MW
Darlington 1630MW
Pickering 2668MW
Portlands GS 459MW
Sithe-Goreway GS 615MW
Halton Hills GS 600MW
Calpine 1000.0MW
St Clair 500.0MW
Brighton Beach 526.0MW
Windsor (115kV) 192.4MW
TransAlta 370.8MW
Imperial Oil 0.0MW
101MW
C23Z & C24Z
Port Alma Wind Project
99MW
WT1T
Erie Shores Wind Project
46.1MW/90.4MVAr
2.5MW/67.0MVAr
268.9MW/-9.5MVAr
268.9MW/-9.5MVAr
349.6MW/-54.4MVAr
345.7MW/-56.3MVAr
M28B
M27B
Q25BM
Q23BM
242.1kV
Burlington
230kV
243.6kV
230kV
121.3kV
115kV
113.5MVAr
562.9MVAr
Trafalgar
0.0MVAr
309.8MW/4.7MVAr
347.6MW/19.3MVAr
386.9MW/-19.2MVAr
387.1MW/-19.2MVAr
R21T
R19T
R17T
R14T
Richview
230kV
244.6kV
244.7kV
394.2MVAr
394.9MVAr
Manby
322.9MVAr
323.9MVAr
FETT
-263.1MW 148.8MVAr
470.3MW 64.1MVAr
533.6kV
500kV
533.1kV
282.0MW 53.8MVAr
179.6MW 88.2MVAr
Middleport
230kV
246.6kV
244.9kV
401.0MVAr
395.4MVAr
N581M
N580M
46.8MW/33.7MVAr
42.1MW/35.6MVAr
119.5MW/72.9MVAr
78.7MW/52.7MVAr
QFW
1497.5MW
1158.3MW -5.1MVAr
19.0MW 136.8MVAr
651.8MW 106.2MVAr
N582L
Nanticoke
500kV
230kV
4 units
4 units
538.0kV
249.9kV
0.0MVAr
0.0MW 160.8MVAr
0.0MW 160.8MVAr
0.0MW 136.9MVAr
0.0MW 136.9MVAr
Load Flow Results:
Primary Demand: 28400MW
With Eight Bruce Units & 725MW of Wind-turbine Generation in Bruce Area
With a new 500kV Double-circuit Line: Bruce to Milton TS
With 870MW of new generation capacity incorporated via the 500kV busbars at the Bruce Complex
With Four Nanticoke Units on-condense
Contingency Condition:
Breaker failure condition resulting in the simultaneous loss of an MxV circuit and one of the 500kV circuits to Trafalgar TS
MICHIGAN IMPORTS: 1499.8MW
NEW YORK IMPORTS at Niagara: 1013.1MW
Losses on the Ontario System: 1321.2MW
DIAGRAM 18
24th March 2007



Load Flow Results: *Primary Demand: 28400MW*

With Eight Bruce Units & 725MW of Wind-turbine Generation in Bruce Area
With a new 500kV Double-circuit Line: Bruce to Milton TS
With 870MW of new generation capacity incorporated via the 500kV busbars at the Bruce Complex
With Four Nanticoke Units on-condense

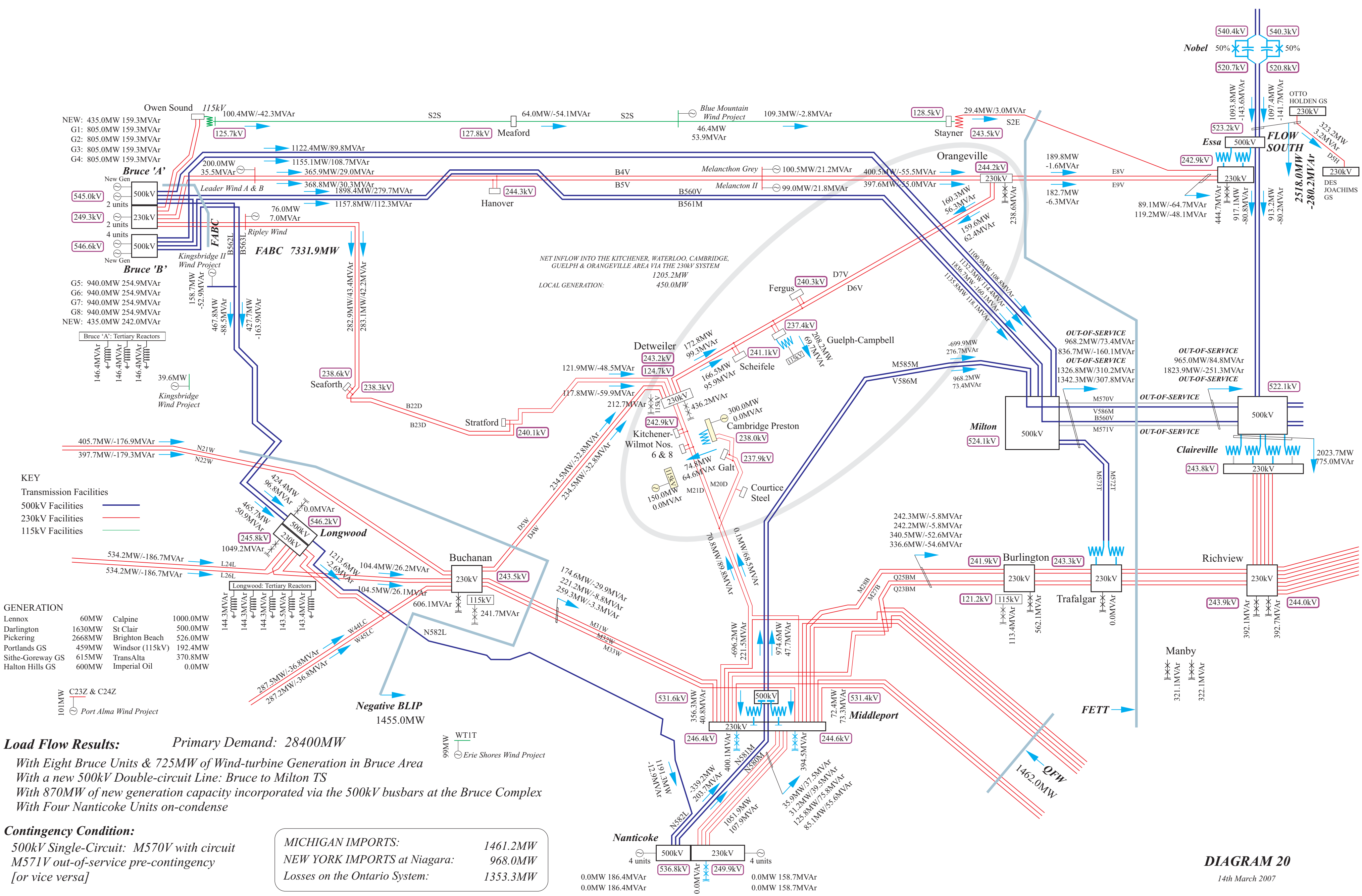
Contingency/Outage Condition:

500kV Single-Circuit: M571V

MICHIGAN IMPORTS:	1504.3MW
NEW YORK IMPORTS at Niagara:	997.2MW
Losses on the Ontario System:	1307.4MW

DIAGRAM 19

13th March 2007



Load Flow Results:

Primary Demand: 28400MW

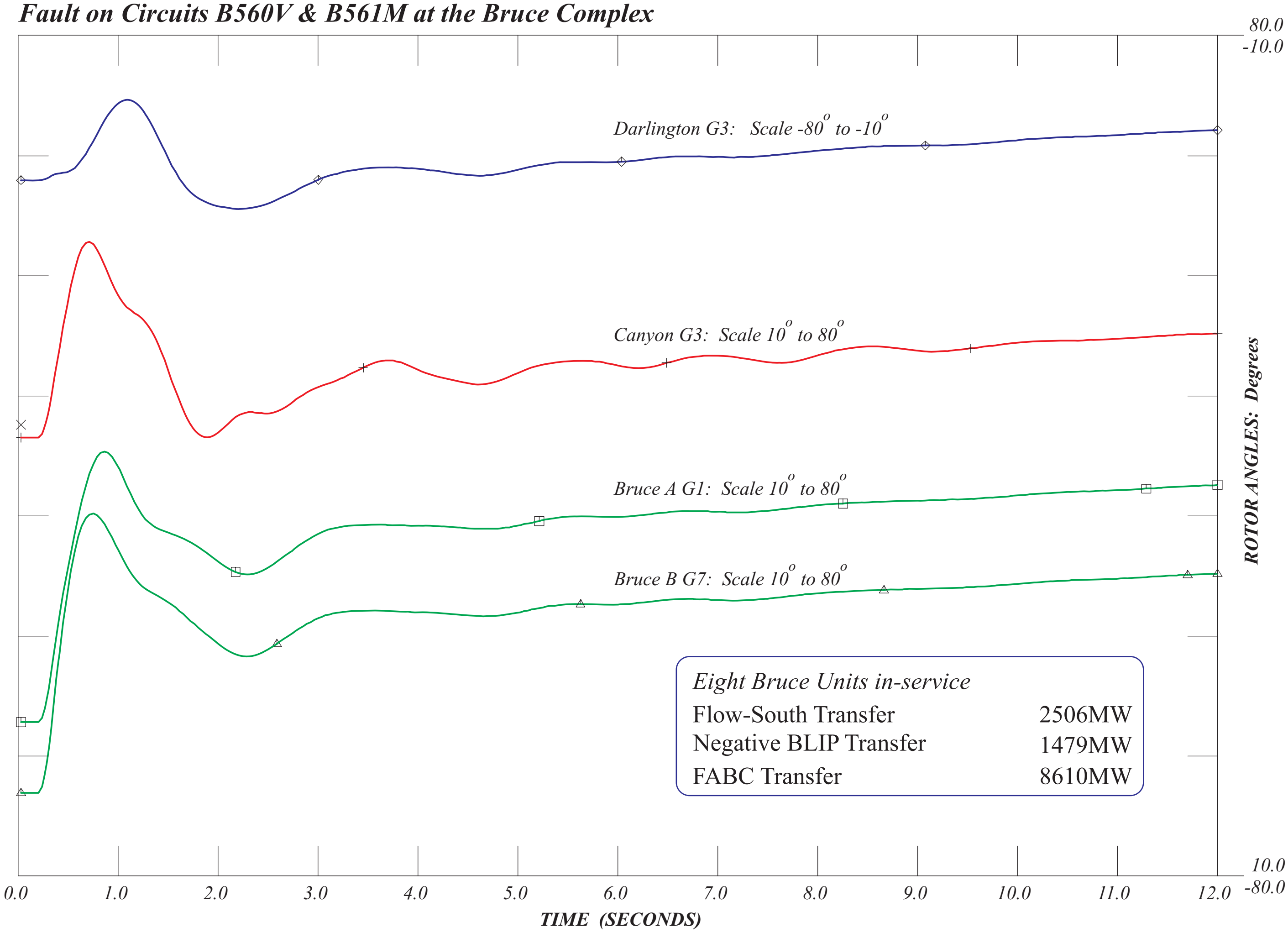
With Eight Bruce Units & 725MW of Wind-turbine Generation in Bruce Area
With a new 500kV Double-circuit Line: Bruce to Milton TS
With 870MW of new generation capacity incorporated via the 500kV busbars at the Bruce Complex
With Four Nanticoke Units on-condense

Contingency Condition:

500kV Single-Circuit: M570V with circuit M571V out-of-service pre-contingency [or vice versa]

MICHIGAN IMPORTS:	*1461.2MW*
NEW YORK IMPORTS at Niagara:	*968.0MW*
Losses on the Ontario System:	*1353.3MW*

Generator Rotor Angle Responses to a Line-Line-Ground Fault on Circuits B560V & B561M at the Bruce Complex



Busbar Voltages in Response to a Line-Line-Ground Fault on Circuits B560V & B561M at the Bruce Complex

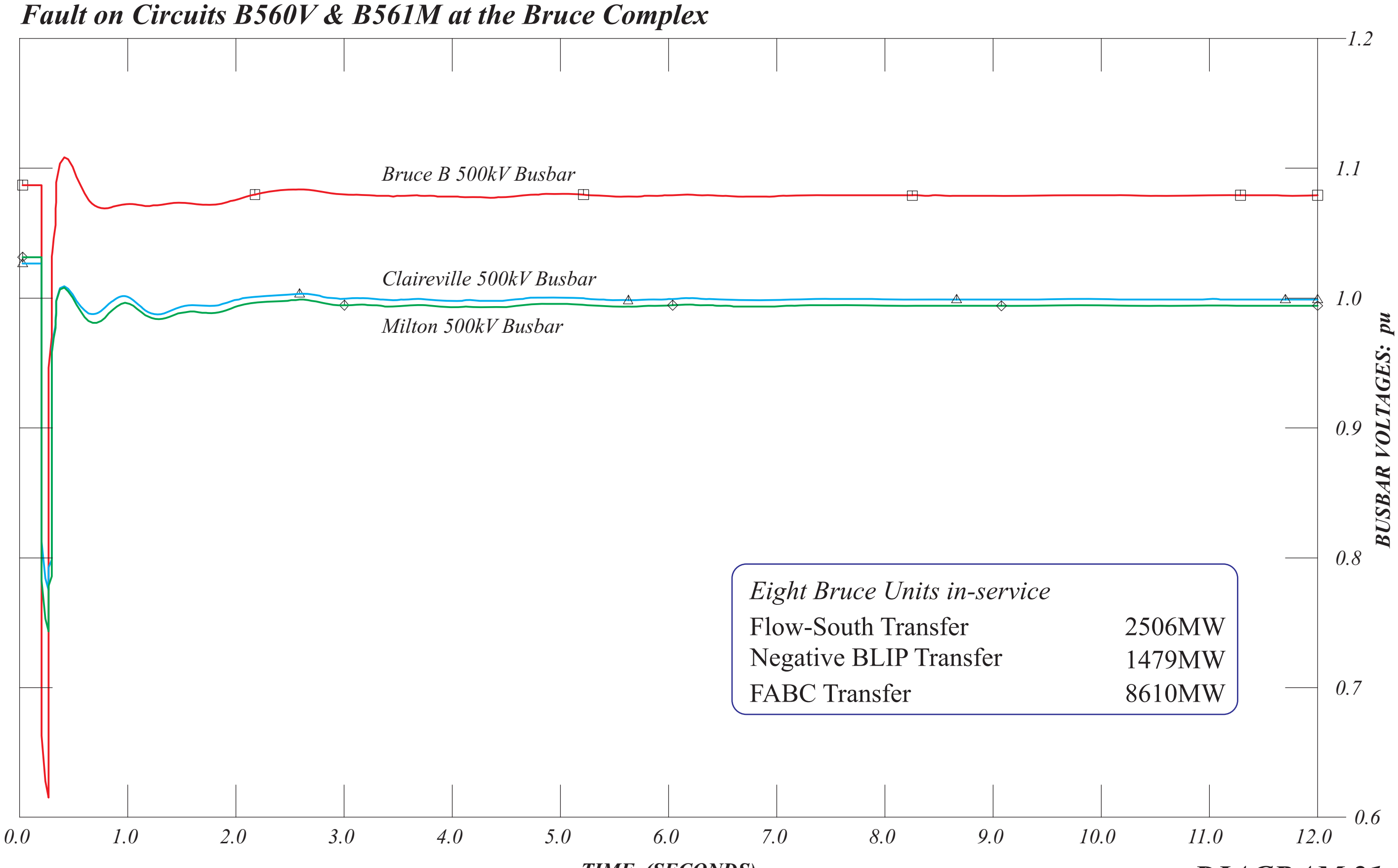


DIAGRAM 21

24th March 2007

CUSTOMER IMPACT ASSESSMENT

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

CUSTOMER IMPACT ASSESSMENT

BRUCE X MILTON NEW 500 kV DOUBLE CIRCUIT LINE

Revision: Final

Date: March 6, 2007

Issued by: **System Investment Division**
Hydro One Networks Inc.

Prepared by:

M. Stelmach

Magdalena Stelmach
Transmission System Development
Hydro One Networks Inc.

Reviewed by:

John Sabiston
Transmission Plans Manager - West
Transmission System Development
Hydro One Networks Inc.

Disclaimer

This Customer Impact Assessment was prepared based on information available about the connection of the proposed 500 kV double circuit transmission line. It is intended to highlight significant impacts, if any, to affected transmission customers early in the project development process and thus allow an opportunity for these parties to bring forward any concerns that they may have. Subsequent changes to the required modifications or the implementation plan may affect the impacts of the proposed connection identified in Customer Impact Assessment. The results of this Customer Impact Assessment are also subject to change to accommodate the requirements of the IESO and other regulatory or municipal authority requirements.

Hydro One shall not be liable to any third party which uses the results of the Customer Impact Assessment under any circumstances whatsoever for any indirect or consequential damages, loss of profit or revenues, business interruption losses, loss of contract or loss of goodwill, special damages, punitive or exemplary damages, whether any of the said liability, loss or damages arises in contract, tort or otherwise.

CUSTOMER IMPACT ASSESSMENT
BRUCE X MILTON NEW 500 kV DOUBLE CIRCUIT LINE

1.0 INTRODUCTION

1.1 Background

Hydro One Networks has been working with stakeholders to explore options to increase the transmission capacity of its network throughout southwestern Ontario. The goal is to accommodate the restart of Bruce Power's units #1 and #2 (1500 MW total) and 725 MW of wind generation in the Bruce area. These wind generators have signed contracts with the Ontario Power Authority (OPA).

This transmission capacity is needed by the end of 2011 and will be provided by building a new double circuit 500 kV line between the Bruce complex and Milton SS. Hydro One is to carry out Customer Impact Assessment (CIA) studies to assess the impact of the proposed transmission circuits on the customers. This is in accordance with the Market Rules (Chapter 4, Section 6) and IESO's CAA process.

1.2 Bruce x Milton 500 kV Double Circuit Line and Terminations

The proposed line is a 2-km single-circuit 500 kV line from Bruce A TS to Bruce Junction and a 3-km single-circuit 500 kV line from Bruce B SS to Bruce Junction on existing multi-line corridors within the Bruce complex. From Bruce Junction to Milton SS, the proposed 173 km 500 kV double-circuit would be adjacent to the existing right-of-way for 500 kV lines. A schematic is shown in Figure 1.

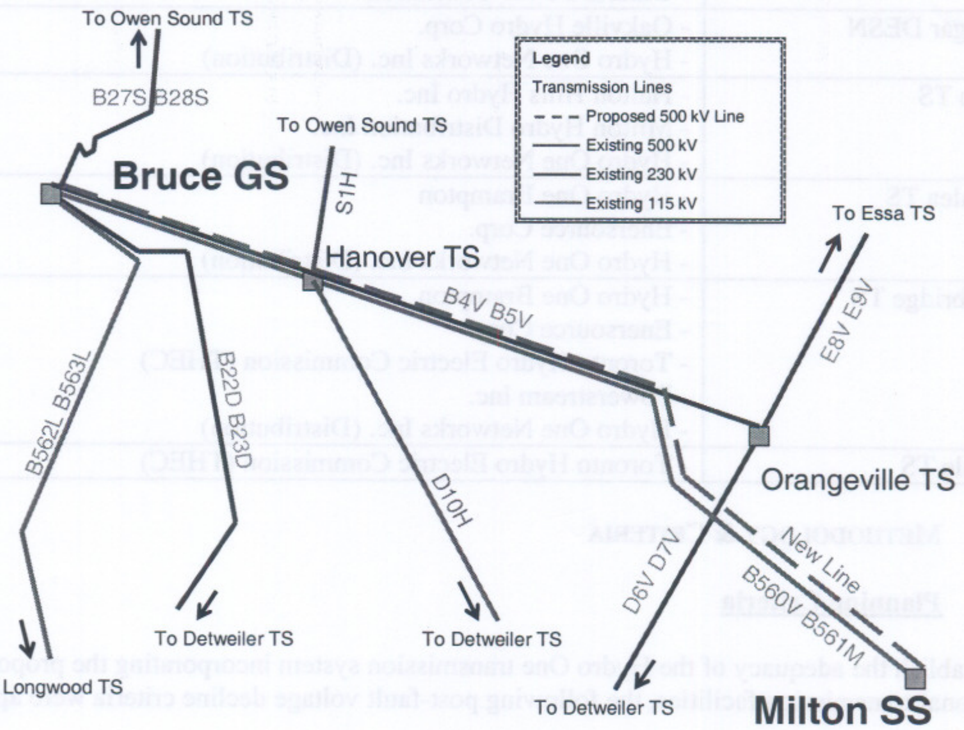


Figure 1: Proposed Facilities with New 500 kV Double Circuit Line

There will be an addition of two new circuit breakers at Milton TS, one new breaker at Bruce A TS and two new breakers at Bruce B SS. Work at all stations will require bus modifications, line terminal equipment, modifications to telecommunications, and modifications and additions to protection and control facilities.

1.3 Customer Connections

The purpose of this CIA is to assess the potential impacts on customers affected by the addition of the new line. In theory, all transmission customers in the GTA and southwestern Ontario are affected. However, this CIA will only study customers connected to stations near the terminals of the new line since they will be most affected by the addition of the line. For the Bruce end, these would be customers at Bruce A TS, Bruce B SS and Douglas Point TS. For the Milton end, the stations that will be studied are Trafalgar DESN, Halton TS, Bramalea TS, Woodbridge TS and Rexdale TS. Table 1 summarizes the customers connected at each station:

Table 1: Customers Connected to Stations Affected by New Circuit

Station	Customers
Bruce A TS	- Bruce Power Inc.
Bruce B SS	- Bruce Power Inc.
Douglas Point TS	- Westario Power Inc. - Bruce Power Inc. - Hydro One Networks Inc. (Distribution) - Huron Wind Limited Partnership - Ontario Power Generation
Trafalgar DESN	- Oakville Hydro Corp. - Hydro One Networks Inc. (Distribution)
Halton TS	- Halton Hills Hydro Inc. - Milton Hydro Distribution Inc. - Hydro One Networks Inc. (Distribution)
Bramalea TS	- Hydro One Brampton - Enersource Corp. - Hydro One Networks Inc. (Distribution)
Woodbridge TS	- Hydro One Brampton - Enersource Corp. - Toronto Hydro Electric Commission (THEC) - Powerstream Inc. - Hydro One Networks Inc. (Distribution)
Rexdale TS	- Toronto Hydro Electric Commission (THEC)

2.0 METHODOLOGY & CRITERIA

2.1 Planning Criteria

To establish the adequacy of the Hydro One transmission system incorporating the proposed additional transmission facilities, the following post-fault voltage decline criteria were applied:

- The loss of a single transmission circuit should not result in a voltage decline greater than 10% for pre- transformer tap-changer action (including station loads) and 10% post-transformer tap-changer action (5% for station loads) ;

- The loss of a double transmission circuit should not result in a voltage decline greater than 10% for pre- transformer tap-changer action (including station loads) and 10% post- transformer tap-changer action (5% for station loads) ;
- Voltages below 50 kV shall be maintained in accordance with CSA 235.

2.2 Study Assumptions

- The following proposed generators are modeled in the basecase used for power flow voltage analysis:
  - St. Clair Energy Centre is connected to L25N and L27N (570 MW)
  - Greenfield Energy Centre is connected to Lambton 230 kV bus (1005 MW)
  - Sithe Goreway Gas is connected to V72R and V73R (1139 MW)
  - Portlands Energy Centre is connected to Hearn 115 kV bus (550 MW)
  - Kingsbridge I Wind Farm is connected to LV bus at Goderich TS (39.6MW)
  - Kingsbridge II Phase I Wind Farm is connected to B562L (160MW)
  - Amaranth (Melancthon) I and II Wind Farm is connected to B4V and B5V (199MW)
  - Kruger Wind Farm is connected to C23J and C24J (100MW)
  - Ripley Wind Farm is connected to B22D and B23D (76MW)
  - Enbridge Leader Wind Farm is connected to B4V and B5V
- Lambton GS is assumed out-of-service. Nanticoke GS is used as synchronous condenser only. Total of 6 Pickering GS units and 8 Bruce GS units are assumed in-service.
- All loads are modeled as constant MVA loads.

2.3 Power System Analysis

Power system analysis is an integral part of the transmission and distribution planning process. It is used by Hydro One to evaluate the capability of the existing network to deliver power and energy from generating stations to provide a reliable supply to customers. Two types of studies are used:

a. Short-Circuit Studies: Short circuit studies are used to determine the impact of the Bruce and Milton area customers at their points of connection to Hydro One.

b. Load Flow Studies: The PTI PSS/E AC load flow program was used to set up detailed base cases with the new 500 kV double circuit line.

3.0 ASSESSMENT OF HYDRO ONE NETWORKS SHORT CIRCUIT LEVELS AT CUSTOMER CONNECTION

Short-circuit studies were carried out to assess the fault contribution when the new Bruce x Milton line is connected. The study area encompasses 500 kV and 230 kV stations near the terminals of the new double circuit line. The following are study assumptions used for short circuit studies:

- Base case assumes existing & committed generating facilities in-service.
- Pre-fault voltage of 550.00 kV at 500 kV stations is assumed.
- Pre-fault voltage of 250.00 kV at 220 kV stations is assumed.
- Pre-fault voltage of 46.00 kV at 44 kV stations is assumed.
- Pre-fault voltage of 29.00 kV at 27.6 kV stations is assumed.

The study results are summarized in Table 2 and Table 3 below and show both symmetric and asymmetric (3-cycle) fault currents and percentage increase after adding the new line. The study also assumes maximum contribution from all the planned generation additions.

Table 2: Symmetrical Fault Levels

Bus	3-Phase Fault Levels (kA)			L-G Fault Levels (kA)		
	Without New Line	With New Line	% Change	Without New Line	With New Line	% Change
Bruce A TS 500 kV	30.3	34.6	**14.2**	35.9	40.1	**11.7**
Bruce B TS 500 kV	30.5	34.8	**14.1**	35.9	40	**11.4**
Bruce A TS 230 kV	32.8	34.2	**4.3**	42	43.6	**3.8**
Bramalea TS 44 kV (EZ Bus)	21.5	21.5	**0.0**	7.9	7.9	**0.0**
Bramalea TS 44 kV (JQ Bus)	17.1	17.1	**0.0**	7.5	7.5	**0.0**
Douglas Point TS 44 kV	12.7	12.8	**0.8**	17.5	17.6	**0.6**
Woodbridge TS 44 kV	12.8	12.8	**0.0**	5.4	5.4	**0.0**
Bramalea TS 27.6 kV	12.8	12.8	**0.0**	10.1	10.1	**0.0**
Halton TS 27.6 kV	12.9	12.9	**0.0**	10.1	10.1	**0.0**
Rexdale TS 27.6 kV (BY Bus)	13.6	13.6	**0.0**	10.4	10.4	**0.0**
Rexdale TS 27.6 kV (JQ Bus)	13.7	13.7	**0.0**	10.4	10.5	**1.0**
Trafalgar DESN 27.6 kV	16.6	16.6	**0.0**	11.5	11.5	**0.0**
Woodbridge TS 27.6 kV	16.3	16.3	**0.0**	11.7	11.7	**0.0**

Table 3: Asymmetrical Fault Levels

Bus	3-Phase Fault Levels (kA)			L-G Fault Levels (kA)		
	Without New Line	With New Line	% Change	Without New Line	With New Line	% Change
Bruce A TS 500 kV	41.6	46.6	**12.2**	49.3	54.6	**10.7**
Bruce B TS 500 kV	41.6	47.0	**13.0**	49.1	54.3	**10.8**
Bruce A TS 230 kV	45.9	48.0	**4.7**	60.2	62.5	**3.8**
Bramalea TS 44 kV (EZ Bus)	28.3	28.4	**0.4**	9.9	9.9	**0.0**
Bramalea TS 44 kV (JQ Bus)	22.4	22.4	**0.0**	9.6	9.6	**0.0**
Douglas Point TS 44 kV	14.5	14.5	**0.0**	22.2	22.4	**0.9**
Woodbridge TS 44 kV	17.0	17.0	**0.0**	7.6	7.6	**0.0**
Bramalea TS 27.6 kV	16.9	16.9	**0.0**	14.0	14.0	**0.0**
Halton TS 27.6 kV	17.2	17.3	**0.6**	14.2	14.2	**0.0**
Rexdale TS 27.6 kV (BY Bus)	16.2	16.2	**0.0**	13.4	13.4	**0.0**
Rexdale TS 27.6 kV (JQ Bus)	16.3	16.3	**0.0**	13.4	13.4	**0.0**
Trafalgar DESN 27.6 kV	22.2	22.2	**0.0**	16.1	16.2	**0.7**
Woodbridge TS 27.6 kV	19.3	19.3	**0.0**	15.0	15.0	**0.0**

Fault levels meet maximum symmetrical three-phase and single line-to-ground faults (kA) for 500 kV, 230 kV and 27.6 kV criteria for all equipment connected to Hydro One transmission system as set out in Appendix 2 of the *Transmission System Code* (TSC). The maximum symmetrical three-phase and single line-to-ground faults given in the TSC may be summarized as follows:

Nominal Voltage (kV)	*Max. 3-Phase Fault (kA)*	*Max. SLG Fault (kA)*
500	80	80
230	63	80
44	20	19
27.6	17	12 (4 wire)/ 0.45 (3 wire)
13.8 and under	21	10

The short circuit level on the 44 kV bus EZ at Bramalea TS (shown shaded) exceeds the TSC criteria. Solutions are under investigation and will be implemented before the in-service date of the new line. However, the new Bruce x Milton line does not impact the short circuit level at Bramalea TS.

As a result of the new line, the maximum symmetrical short circuit increase was 14.2% at Bruce A TS and the maximum asymmetrical short circuit increase was 13.0% at Bruce B SS. The new levels are well within the capabilities of the equipment. There is very limited increase in short circuit levels at 230 kV, 44 kV and 27.7 kV stations and these levels are also well within the capabilities of the equipment.

4.0 ASSESSMENT OF HYDRO ONE NETWORKS VOLTAGE PERFORMANCE AT CUSTOMER CONNECTION

Load flow studies were carried out for the incorporation of the new transmission circuit. These studies reviewed the voltage performance on the local 500 kV system and customer stations in the vicinity. The area under study encompasses Bruce A TS, Bruce B SS, Douglas Point TS, Trafalgar DESN, Halton TS, Bramalea TS, Woodbridge TS and Rexdale TS.

Local voltage impact was assessed using post-contingency load flows. Tests for the voltage impact were conducted using the following contingencies:

a) A single contingency loss of B560V from Bruce A TS to Claireville TS
b) A double contingency loss of B560V and B561M from Bruce A TS to Claireville TS and Bruce B SS to Milton SS, respectively. For the double contingency, reactors at Longwood TS and Bruce A TS were switched off for both the immediate post-contingency and steady-state post contingency studies.

Tests were only conducted with the new circuits in service since the circuits are necessary to achieve the required transfer capacity out of Bruce. Results for tests are shown in Tables 4-5 and summarized below:

- Table 4: Maximum voltage decline is 1.2% at the 27.6 kV Halton buses and Trafalgar DESN following tap-changer movement after the contingency.

- Table 5: Maximum voltage decline is 1.3% at the Halton TS 27.6 kV Q bus and the Douglas Point 44 kV bus immediately following the contingency.

Following the worst contingency with the new circuits in place, the voltage changes are well within the voltage decline guideline for customer buses of less than 10% and 5% voltage drop before and after transformer tap-changer operation.

Table 4: Loss of B560V

	Pre-C Voltage	Before ULTC Post-C Voltage		After ULTC Post-C Voltage	
		Voltage	% Change	Voltage	% Change
Bruce A TS 500 kV	544.6	541.3	-0.6%	541.9	-0.5%
Bruce B TS 500 kV	545.0	541.6	-0.6%	542.2	-0.5%
Bruce A TS 230 kV	248.2	246.7	-0.6%	247.0	-0.5%
Bramalea TS 44 kV (T3/T4)	44.9	44.9	0.0%	44.9	0.0%
Bramalea TS 44 kV (T5/T6)	44.6	44.6	0.0%	44.6	0.0%
Douglas Point TS 44 kV (T3/T4)	45.0	44.7	-0.6%	44.7	-0.5%
Woodbridge TS 44 kV (T3/T5)	44.9	44.6	-0.8%	44.5	-0.8%
Bramalea TS 27.6 kV (T1/T2 B Bus)	28.5	28.2	-0.9%	28.2	-1.0%
Bramalea TS 27.6 kV (T1/T2 Y Bus)	28.7	28.5	-0.9%	28.5	-1.0%
Halton TS 27.6 kV (T3/T4 J Bus)	28.7	28.4	-1.1%	28.4	-1.2%
Halton TS 27.6 kV (T3/T4 Q Bus)	28.4	28.0	-1.1%	28.0	-1.2%
Rexdale TS 27.6 kV (T1/T2 BY Bus)	28.4	28.1	-1.0%	28.1	-1.0%
Rexdale TS 27.6 kV (T1/T2 JQ Bus)	27.8	27.5	-0.9%	27.5	-1.0%
Trafalgar DESN 27.6 kV (T1/T2)	28.3	28.0	-1.1%	27.9	-1.2%
Woodbridge TS 27.6 kV (T3/T5)	28.3	28.0	-1.0%	28.0	-1.0%

Table 5: Loss of B560V/561M (Reactors Switched Off)

	Pre-C Voltage	Before ULTC Post-C Voltage		After ULTC Post-C Voltage	
		Voltage	% Change	Voltage	% Change
Bruce A TS 500 kV	544.6	543.8	-0.1%	544.4	0.0%
Bruce B TS 500 kV	545.0	544.1	-0.2%	544.5	-0.1%
Bruce A TS 230 kV	248.2	251.2	1.2%	248.6	0.2%
Bramalea TS 44 kV (T3/T4)	44.9	44.9	0.0%	44.9	0.0%
Bramalea TS 44 kV (T5/T6)	44.6	44.6	0.0%	44.6	0.0%
Douglas Point TS 44 kV (T3/T4)	45.0	45.5	1.3%	45.0	0.2%
Woodbridge TS 44 kV (T3/T5)	44.9	44.5	-1.0%	44.5	-0.8%
Bramalea TS 27.6 kV (T1/T2 B Bus)	28.5	28.2	-1.1%	28.2	-0.9%
Bramalea TS 27.6 kV (T1/T2 Y Bus)	28.7	28.4	-1.1%	28.5	-0.9%
Halton TS 27.6 kV (T3/T4 J Bus)	28.7	28.4	-1.2%	28.5	-0.9%
Halton TS 27.6 kV (T3/T4 Q Bus)	28.4	28.0	-1.3%	28.1	-0.9%
Rexdale TS 27.6 kV (T1/T2 BY Bus)	28.4	28.1	-1.2%	28.1	-1.0%
Rexdale TS 27.6 kV (T1/T2 JQ Bus)	27.8	27.5	-1.2%	27.5	-1.0%
Trafalgar DESN 27.6 kV (T1/T2)	28.3	27.9	-1.2%	28.0	-0.9%
Woodbridge TS 27.6 kV (T3/T5)	28.3	28.0	-1.2%	28.0	-1.0%

The maximum and minimum phase-to-phase voltages given in the IESO's Transmission Assessment Criteria and Canadian Standard Association document CAN-3-C235-83 are as follows:

Nominal Voltage (kV)	*Maximum Voltage (kV)*	*Minimum Voltage (kV)*
500	550	490
230	250*	220
44	+6% nominal = 46.64	-6% nominal = 41.51
27.6	+6% nominal = 29.26	-6% nominal = 26.04

*Certain buses can be assigned specific maximum and minimum voltages as required for operations. In northern Ontario, the maximum continuous voltage for the 230 systems can be as high as 260kV. *[from IESO document IMO_REQ_0041 Issue 2.0]*

5.0 PRELIMINARY OUTAGE IMPACT ASSESSMENT

Outages associated with the construction work to connect the new double circuit 500 kV line will be identified when a detailed construction schedule is established in the engineering phases of project development.

6.0 CONCLUSIONS AND RECOMMENDATIONS

This Customer Impact Assessment (CIA) presents results of short-circuit and voltage performance study analyses. The report has confirmed that the new double circuit line can be incorporated without any adverse impacts on southwestern Ontario customers.

ONTARIO RELIABILITY OUTLOOK – MARCH 2007

THE ONTARIO RELIABILITY OUTLOOK

MARCH
2007
VOLUME 2 ISSUE 1

ieso
Power to Ontario. On Demand.

ABOVE: IESO Control Room

COVER: Melancthon Wind Project, one of Ontario's new commercial wind farms.

CONTENTS

Transmission towers at sunset. Image courtesy of Hydro One.

EXECUTIVE SUMMARY

The province's future electricity reliability picture has improved significantly as a result of decisions and actions taken since the release of the previous Ontario Reliability Outlook by the Independent Electricity System Operator (IESO) in June, 2006.

About 7,000 megawatts (MW) of new or refurbished generation has been contracted to come into service by 2011. The new supply will address previously identified concerns in specific areas such as Toronto and the western part of the Greater Toronto Area (GTA) and will contribute to overall improved resource adequacy for the province.

The decision to have the Ontario Power Authority (OPA) and the IESO jointly develop a coal transition plan to meet the government's directive to achieve the phase-out of coal while maintaining electricity supply reliability has addressed concerns identified by the IESO last June. This change will help ensure reliability and address any unforeseen delays in either the completion of planned supply facilities or in meeting conservation and demand management (CDM) targets.

The IESO also implemented a number of new market mechanisms designed to address reliability issues that had surfaced in the summer of 2005. These included the Day Ahead Commitment Process (DACP), intertie failure charges and the Emergency Load Reduction Program (ELRP). Overall, these initiatives resulted in greater certainty of generator availability, fewer transaction failures and additional flexibility for the IESO in managing the reliability of the system.

Consultation is underway with a number of stakeholders related to overall system and local reliability needs. The IESO remains concerned about the uncertainty around the length of approvals processes affecting generation and transmission projects. These approval processes may impact the nature and timing of the implementation of certain transmission and renewable generation projects. The situation is particularly troublesome in the case of new transmission. While some changes have been made, until the approvals process is demonstrated to produce timely decisions, there will continue to be a risk that transmission will not be available when it is required.

Through regular issues of the Ontario Reliability Outlook, the IESO reports on progress of the inter-related generation, transmission and demand management projects underway to meet future reliability requirements. As project commitments are made by the OPA, or included in the Integrated Power System Plan (IPSP), the Ontario Reliability Outlook will monitor and report on the progress of infrastructure developments and their impact on future reliability.

New Supply Being Introduced

Ontario's electricity sector is in the early stages of the biggest infrastructure change in its history. Over the next decade, a number of aging and existing generating facilities will near or reach the end of their planned operating life, and refurbishments to extend reliable operation or replacement of these aging facilities will be necessary.

Increasing climate change concerns will continue to point to the need to reduce the use of coal-fired generating facilities, which are planned to be shut down as soon as reliability allows. In 2006, generation from coal-fired facilities was down three per cent from the previous year with a corresponding reduction in emissions. The deferral of the planned shutdown of Ontario's four coal-fired generating stations has largely addressed the concern over future supply needs, identified by the IESO last June. As new facilities come into service and CDM activities progress, reliance on coal to meet demand in Ontario can continue to decline.

More than 3,000 MW of new or refurbished generation has come on-line in Ontario in the past four years, including 700 MW in the past 12 months. Generator performance has also continued to improve over that period. Forced outage rates have declined continuously since 2003 while nuclear capability factors have increased from 78 per cent in 2003 to almost 83 per cent in 2006.[1]

Included in the planned new generation is the Portlands Energy Centre in Toronto which will begin to address the reliability concerns that the IESO had raised about supply to central Toronto. Phase One of the Portlands project, with a contract capacity of 250 MW, is scheduled to be ready to meet demands in the summer of 2008, with Phase Two (288 MW) scheduled to come into service before the summer of 2009.

The almost 1,500 MW of new generation slated to come in service in the western region of the GTA will address the previously identified concerns in that area. Phase One of the Goreway gas-fired generating project is targeted to be in service by this summer and provide 485 MW of new supply. An additional 375 MW from Phase Two of the Goreway project is scheduled for operation in the summer of 2008. The 600 MW Halton Hills gas-fired generating station is scheduled to be brought on-line in 2010.

Wind is making an increased contribution to meeting Ontario's electricity needs. More than 400 MW of wind is currently installed at four locations around the province with approximately 850 MW planned before the end of 2008. For capacity planning purposes, it is assumed that wind generation has a dependable capacity contribution of 10 per cent.

The IESO has been actively addressing wind integration in Ontario and has created a wind power working group comprised of wind generators and other stakeholders to address the various aspects related to the increasing contribution of wind in the Ontario power sector.

More generally, the IESO continues to identify a need to ensure that the future supply and demand response mix has sufficient generation that can be dispatched up or down to match changes in the level of demand. These load following requirements are critical during early morning hours, when demand climbs quickly and in the evening when demand begins to decline.

[1] Source: Canadian Nuclear Association

Over half of Ontario's installed capacity, including nuclear, co-generation, some hydroelectric and wind generating assets are baseload or non-manoeuvrable generation, meaning they cannot routinely be dispatched up and down as demand rises and falls. This type of capacity is expected to grow over the next few years with the addition of 1,500 MW of Bruce A generation and significant amounts of new wind generation.

Baseload and non-manoeuvrable generation must be consumed when it is made available. During certain periods, particularly overnight in the spring and fall, this type of generation can exceed the amount required to meet the demand, resulting in the need to shut down generation. While this can result in wasting available wind or water or in the case of nuclear units, can result in up to a 72 hour shut down, it can also impact reliability if demand rises quickly.

The IESO has undertaken a study to establish a quantifiable measure of load following requirement based on historical demand and market data.

Transmission

New transmission facilities, particularly in southwestern Ontario, remain a priority for the IESO over the next decade. Major transmission projects are required to deliver additional electricity from the Bruce area, to enable the planned expansion of hydroelectric capability in the northeast and to increase the capability to supply Toronto load. Without new transmission facilities, the IESO will eventually be forced to operate existing facilities near their maximum capabilities, with little margin for unexpected events and requiring complex arrangements to do routine maintenance on critical facilities.

A new 500 kV line out of the Bruce area is required as soon as possible to accommodate additional generation expected from new projects and refurbished Bruce nuclear units. Some short-term solutions are available to minimize potential congestion that could begin with the planned restart of Bruce Unit 2 in 2009.

Hydro One has proposed to address the need for short-term transmission enhancements in the northeastern part of the Ontario grid to allow the delivery of planned generation in the area to the southern Ontario load.

Hydro One and TransÉnergie are building a 1,250 MW interconnection which consists of a 230 kV line and back-to-back high-voltage direct-current (HVdc) converters. The new interconnection is scheduled to be brought into service in 2009.

Conservation and Demand Management

The Ontario government has set aggressive CDM targets for the near future.

The OPA and local distribution companies (LDC) have introduced a number of programs, which encourage electricity customers to adopt energy efficiency measures and engage in demand response activities. Targeted CDM savings totalling more than 1,000 MW are being pursued by a number of market participants, including the OPA. It will take some time before the results of the various CDM programs and initiatives can be verified and as such there is a risk in the short-term of relying on the associated contributions to capacity for operational planning.

Reducing peak demand will help contribute to the reliability of the system. Ontario's improved supply situation will help address any delays in achieving CDM savings. As CDM results are confirmed, the IESO will closely monitor their contribution during peak demand and tight supply events in order to reliably and efficiently schedule resources and operate the system.

Sithe Global,
Goreway Station

SUPPLY

A number of the IESO concerns related to supply needs in both the short-term and beyond are being addressed.

The new supply includes three gas-fired generating facilities that will make important contributions to maintaining reliability in and around the GTA. Phase One of the Goreway gas-fired station (485 MW) in Brampton is targeted to come into service before the summer of 2007, and Phase One of the Portlands Energy Centre (250 MW) in Toronto is planned to come into service before the summer of 2008, with Phase Two (288 MW) scheduled to come into service before the summer of 2009. Phase Two of the Goreway station (375 MW) is planned to come into service in the fall of 2008. In addition, the Greenfield South gas-fired generating station (280 MW) is scheduled to come into service in the fall of 2008, although municipal and environmental approvals issues may delay this.

An additional 5,400 MW has been contracted or planned to come into service in the longer term including 1,500 MW of refurbished nuclear generation from the Bruce nuclear facility, 471 MW of hydroelectric generation from the projects on the Mattagami River, 1,575 MW of gas-fired generation in the Sarnia area and approximately 850 MW of additional wind generation.

Trans Canada's new 600 MW Halton Hills Generating Station is expected to come into service in 2010 to help meet increasing demands for electricity in Halton Region and the City of Mississauga.

A number of Combined Heat and Power (CHP) projects totalling more than 400 MW are scheduled to be installed over the next four years.

Required Flexibility

While there are significant supply additions planned, there is a need to ensure that some of that future generation has the ability to rapidly increase or decrease its output to meet demands that can change quickly. The ability to react to changing demands, known as load-following capability, is found in certain types of supply such as coal-fired or gas-fired generators and some hydroelectric generation. Load following requirements are highest during early morning when demand quickly rises and in the evening when demand quickly drops off.

Coal-fired generators are characterized by relatively high ramp rates and low minimum loading points, which translates into timely load following capability over a large range of output levels. Gas-fired generators can also have higher ramp rates and provide operational flexibility if appropriately designed. Many hydroelectric generators can ramp to their full output capability within a matter of minutes. However, during certain periods such as the spring when the snow is melting, they may be unavailable to ramp due to water conditions and regulatory requirements. Dynamic conditions such as these must be carefully considered when determining potential supply mixes for the future.

The IESO continues to be concerned with the future management of the province's water resources as they relate to electricity production. Preserving the operating flexibility of existing hydroelectric facilities and recognizing the capability of new resources should be an important consideration in the development of water management plans.

Over half of Ontario's installed capacity is baseload or non-manoeuvrable, types of supply that include nuclear, run-of-the-river hydro, co-generation and wind. This type of generation has to be used when it is available and does not have the flexibility to be dispatched up or down to meet the demand. While it has limited ability to increase output, it can also become problematic when this type of baseload generation exceeds the amount required to meet the demand. This can happen in the over-night periods during spring or fall resulting in the need to remove that generation from service. In the case of nuclear units where the unit could be shut down for up to 72 hours, it could impact reliability if demand rises quickly.

The IESO is currently studying the potential impact of proposed changes to the supply mix on the load following capability of and requirements for dispatchable generation and load in Ontario.

The IESO has undertaken a study to establish a quantifiable measure of load following requirement based on historical demand and market data. The results of this study will outline typical hourly requirements for load following over the course of a historical year.

The next steps will be to determine how Ontario's existing supply mix satisfies the identified load following requirements; and simulate how well potential supply mixes in the future will meet these requirements. This will likely include a detailed analysis of the amount of load following provided by generation technology type; and will address the potential impact of replacing coal-fired generation with other types of generation.

Wind

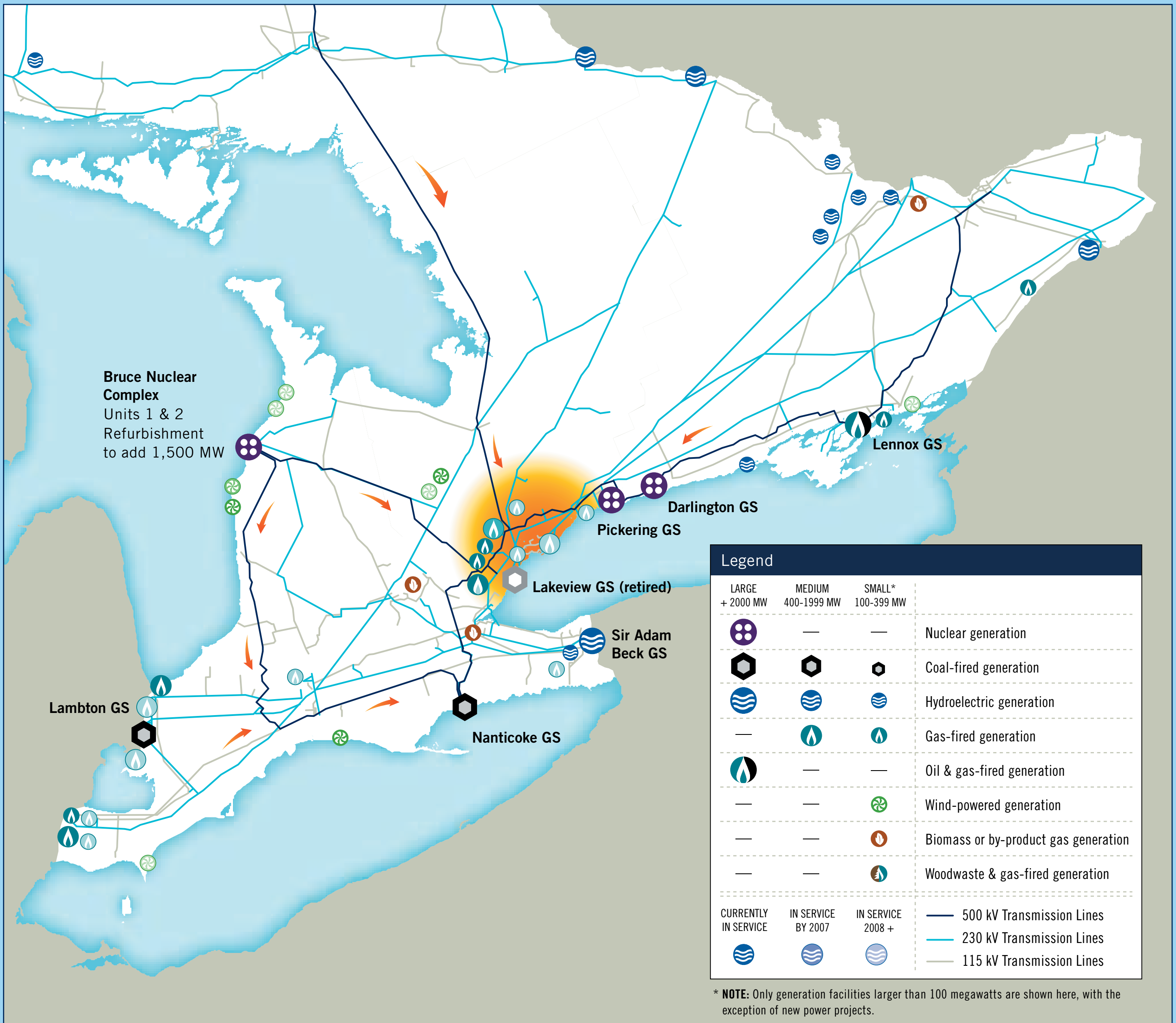
The IESO has been actively addressing wind integration in Ontario. Since the previous Ontario Reliability Outlook was released in June, 2006, the IESO has received the results of a study it co-sponsored on the potential contribution of wind to meeting the province's future power needs. This study, together with a growing body of experience with operational wind farms in Ontario and further study underway will form the basis for necessary changes to operational processes to integrate new facilities.

Approximately 400 MW of wind is currently installed at four locations around the province. Although wind power represents a small portion of the province's total supply mix, it nevertheless has demonstrated a positive contribution. For example over the relatively short period of production experienced with the operational wind farms connected to the grid, the annual energy capacity factor for these wind farms for the period March 2006 through February 2007 averaged 25 per cent. The monthly average capacity factor for the entire wind fleet in the month of December 2006 was 37 per cent.

Several wind projects are under development and are expected to be completed within the next couple of years. Approximately 850 MW of wind power is planned before the end of 2008.

A wind power stakeholdering working group has been created consisting of a variety of members in Ontario that have a special interest and focus on wind generation. The group is actively engaged in obtaining stakeholder feedback to address wind integration issues, to better understand the challenges wind power proponents face in becoming operational in the Ontario market, and to assist in reducing any barriers to participation in the Ontario market.

SOUTHERN ONTARIO ELECTRICITY SYSTEM AT A GLANCE



* **NOTE:** Only generation facilities larger than 100 megawatts are shown here, with the exception of new power projects.

To download a copy of the full map, please visit www.ieso.ca/supply.

A map of Northern Ontario is available on page 10 of this report.

TABLE 1: GENERATION PROJECTS PLANNED OR UNDERWAY IN ONTARIO

SOURCE OF PROJECT	GENERATION PROJECTS PLANNED OR UNDERWAY	INSTALLED CAPACITY (MW)	PLANNED IN-SERVICE DATES
Renewables I RFP – Hydroelectric generation project	Umbata Falls Hydroelectric Project	23	Q2 2008
Government directive for Western GTA – Gas-fired generation projects	Goreway Station – Phase 1	485	Q2 2007
	Goreway Station – Phase 2	375	Q3 2008
GTA West RFP	Halton Hills Generation Station	600	Q2 2010
Government directive for Central Toronto – Gas-fired generation projects	Portlands Energy Centre – Phase I Simple Cycle	250	Q2 2008
	Portlands Energy Centre – Phase II Combined Cycle	288	Q2 2009
Clean Energy Supply RFP – Gas generation projects	Greenfield Energy Centre	1,005	Q4 2008
	Greenfield South Power Plant	280	Q4 2008
	St. Clair Energy Centre	570	Q1 2009
Renewables II RFP* – Wind generation projects	Wolfe Island Wind Project	198*	Q4 2008
	Leader A Wind Power Project	99*	Q4 2008
	Leader B Wind Power Project	101*	Q4 2008
	Kingsbridge II Wind Power Project	159*	Under review
	Ripley Wind Power Project	76*	Q4 2007
	Kruger Energy Port Alma Wind Power Project	101*	Q4 2008
	Melancthon II Wind Project	132*	Q2 2008
Renewables II RFP – Hydroelectric generation project	Island Falls Hydroelectric Project	20	Q4 2009
Nuclear generation projects underway with Bruce Power	Bruce Power Unit 1 Refurbishment	750	Q1 2010
	Bruce Power Unit 2 Refurbishment	750	Q3 2009
Hydroelectric generation project under development with Ontario Power Generation	Little Long, Harmon, Kipling and Smoky Falls	450	Unit in-service dates ranging from 2009 to 2011
	Lower Sturgeon, Sandy Falls and Wawaitin	16	
	Mattagami Lake Dam	5	
Combined Heat and Power (CHP) RFP – Co-generation projects	Great Northern Tri-Gen Facility	12	Q1 2008
	East Windsor Cogeneration Centre	84	Q2 2009
	Durham College District Energy Project	2	Q2 2008
	Thorold Cogeneration Project	236	Q2 2010
	Countryside London Cogeneration Facility	12	Q2 2008
	Algoma Energy Cogeneration Facility	63	Q2 2009
	Warden Energy Centre	5	Q2 2008

* For capacity planning purposes, wind generation has a dependable capacity contribution of 10 per cent of the listed installed capacity of the project.

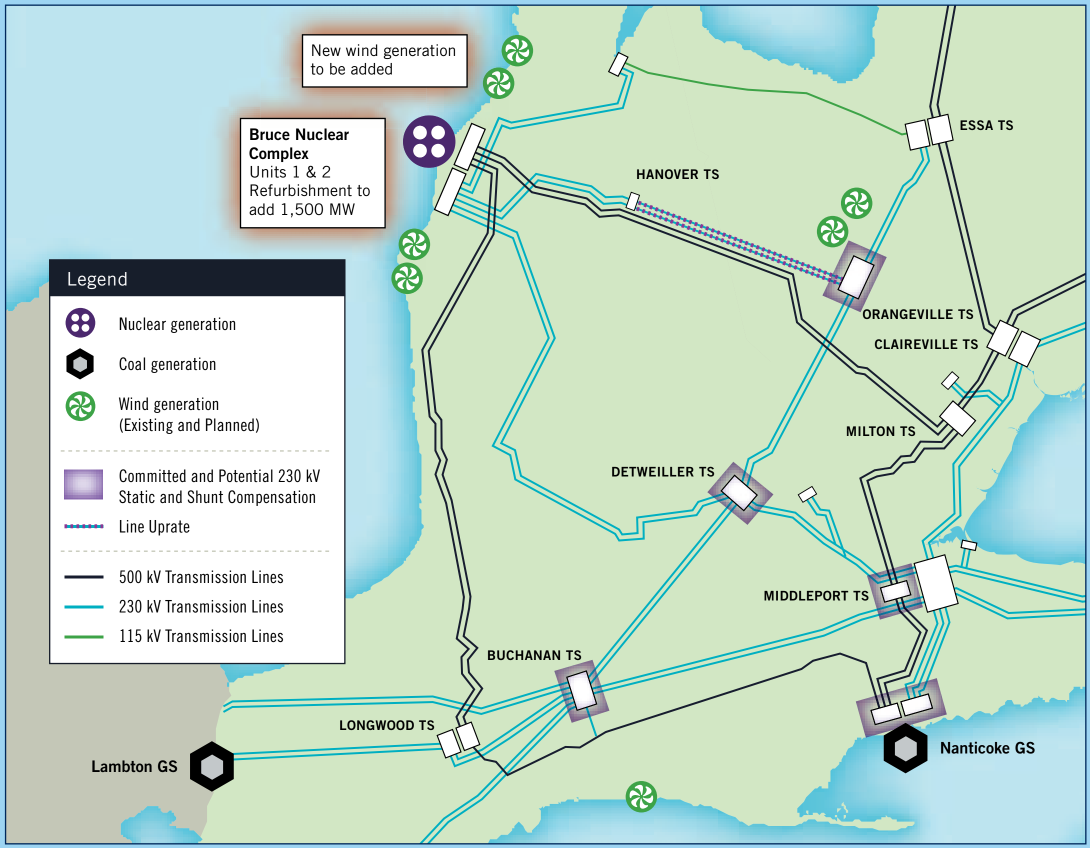
TABLE 2: EXPECTED CONSERVATION AND DEMAND MANAGEMENT SAVINGS

MW SAVINGS	2007	2008	2009	2010
Conservation	40-50	15	30	60
Energy Efficiency		199	463	777
Demand Management	225-250	92	231	370
Fuel Switching		18	46	81
Self-Generation		17	43	69

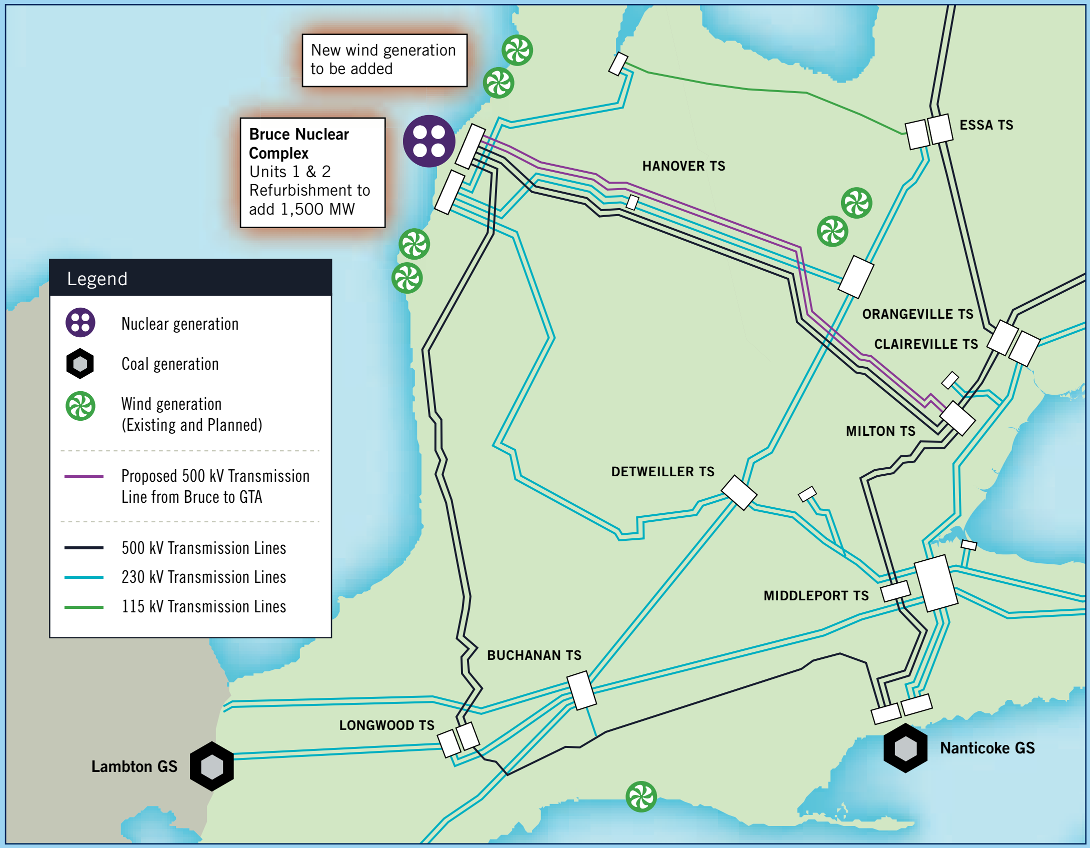
Source: Ontario Power Authority

SOUTHWESTERN ONTARIO

PLANNED NEAR-TERM REINFORCEMENTS



PLANNED LONG-TERM SOLUTIONS



TRANSMISSION

Over the next decade, the need for transmission enhancements is particularly evident in three areas of the province:

- In southwestern Ontario to deliver additional nuclear and wind supply from the Bruce area;
- In the northeast to enable the planned expansion of hydroelectric capability, and;
- In the Toronto region in order to improve reliability to Canada's largest city.

Without new transmission facilities, the IESO will be forced to operate existing facilities near their maximum capabilities, with little margin for unexpected events and requiring complex arrangements to do routine maintenance on critical facilities. A number of local transmission or generation initiatives are also needed in areas throughout Ontario. Hydro One has started work on all the transmission projects that are required in the near-term and the majority are already under construction. The IESO believes that work on local generation procurement in areas such as York Region needs to start expeditiously.

Southwestern Ontario

Enhancing the transmission system in southwestern Ontario, in particular to deliver the planned and future increases in generating capability in and around the Bruce peninsula, continues to be a high priority.

Currently, there is inadequate transmission out of the Bruce area to accommodate both the expected wind developments in that area and the expanded capacity of the Bruce nuclear station resulting from planned refurbishments. Some near-term reinforcements include the up-rating of the Hanover to Orangeville 230 kilovolt (kV) circuits, and the installation of additional voltage support facilities at various transmission stations in southwestern Ontario. These will increase the transfer capability out of Bruce in the short-term. A proposed new 500 kV double-circuit line from Bruce toward the GTA will provide the required transmission capability over the long-term to deliver the full capability of the Bruce refurbishment and both planned and potential new renewable resources in the Bruce area.

The new 500 kV line out of the Bruce area is required as soon as possible to accommodate the additional generation from both new wind projects and refurbished Bruce nuclear units. To minimize potential congestion costs, interim measures, that could begin as early as 2009, are being assessed. These measures include the use of generation rejection of Bruce units and wind turbines, 30 per cent series compensation of the existing 500 kV lines between Bruce, Longwood and Nanticoke, and restricting further generation development in the Bruce area, in addition to the near-term reinforcements described above. These measures are not substitutes for a new line, as they will not eliminate congestion and will increase the operational complexity of this part of the transmission system, and will stretch its design capability. However these measures are expected to reduce the amount of congestion until a new line is built.

Additional transfer capability may also be needed between Sarnia and London to facilitate imports from Michigan and energy from the new natural gas-fired generators in this area. The phase-out of the Lambton coal-fired generation station will alleviate this need. As the Nanticoke coal-fired station is phased out over the next decade, additional voltage support in southwestern Ontario will be required, as reported in previous Ontario Reliability Outlooks.

Additional transmission capacity is needed as a result of growing load in a number of cities in southwestern Ontario and transmission reinforcements are required to facilitate the development of generation from renewable resources, including wind generation on parts of Lake Huron and Lake Erie.

North – South

Hydro One has proposed to address the need for transmission enhancements in the northeastern part of the Ontario grid to allow the delivery of planned generation in northeastern Ontario to southern Ontario.

The System Impact Assessment Report for Hydro One's application to make certain transmission system modifications to allow the delivery of generation from the northeastern part of the grid is nearing completion. The results are expected to confirm the need for series capacitors at Nobel Transmission Station (TS), a static var compensator (SVC) at Porcupine TS and a further SVC at Kirkland Lake TS.

This work will address concerns previously identified regarding the need for transmission enhancements to address existing congestion and achieve full availability of additional output from the expansion of the four existing hydroelectric stations on the Lower Mattagami River and other committed renewable energy developments in northeastern Ontario.

Toronto and Surrounding Area

Concerns identified in late 2005 about supply to the central Toronto area are being alleviated with the construction of the Portlands Energy Centre. Phase One, representing 250 MW, is expected to be implemented in time to help meet demands during the summer of 2008.

The central Toronto area is currently served through two transmission paths into the area. The IESO continues to raise the need for a third path in the next decade in order to maintain long-term reliability and to provide a diversity of supply paths into the city.

In the York Region, the transformer station capacity has been exceeded due to the rapidly growing loads in the Newmarket and Aurora area. There is an immediate need for a new transformer station in the area. Hydro One plans to have a new transformer station in service before the end of 2008 to address the immediate needs. Longer term, transmission constraints are expected to occur as early as 2011. Local generation proposed by the OPA is expected to alleviate these constraints but work to procure this generation must begin soon.

Ontario – Quebec Interconnection

Hydro One and TransÉnergie are building a 1,250 MW interconnection between Hawthorne TS in Ontario and Outouais station in Quebec consisting of a 230 kV line and back-to-back HVdc converters. Work to accommodate the tie, scheduled to be in service in 2009, will also include improvements to the supply to stations in the Ottawa area.

For a more complete listing of the transmission requirements throughout the province and the projects proposed to meet them, please see Table 3 on page 11.

NORTHERN ONTARIO ELECTRICITY SYSTEM AT A GLANCE

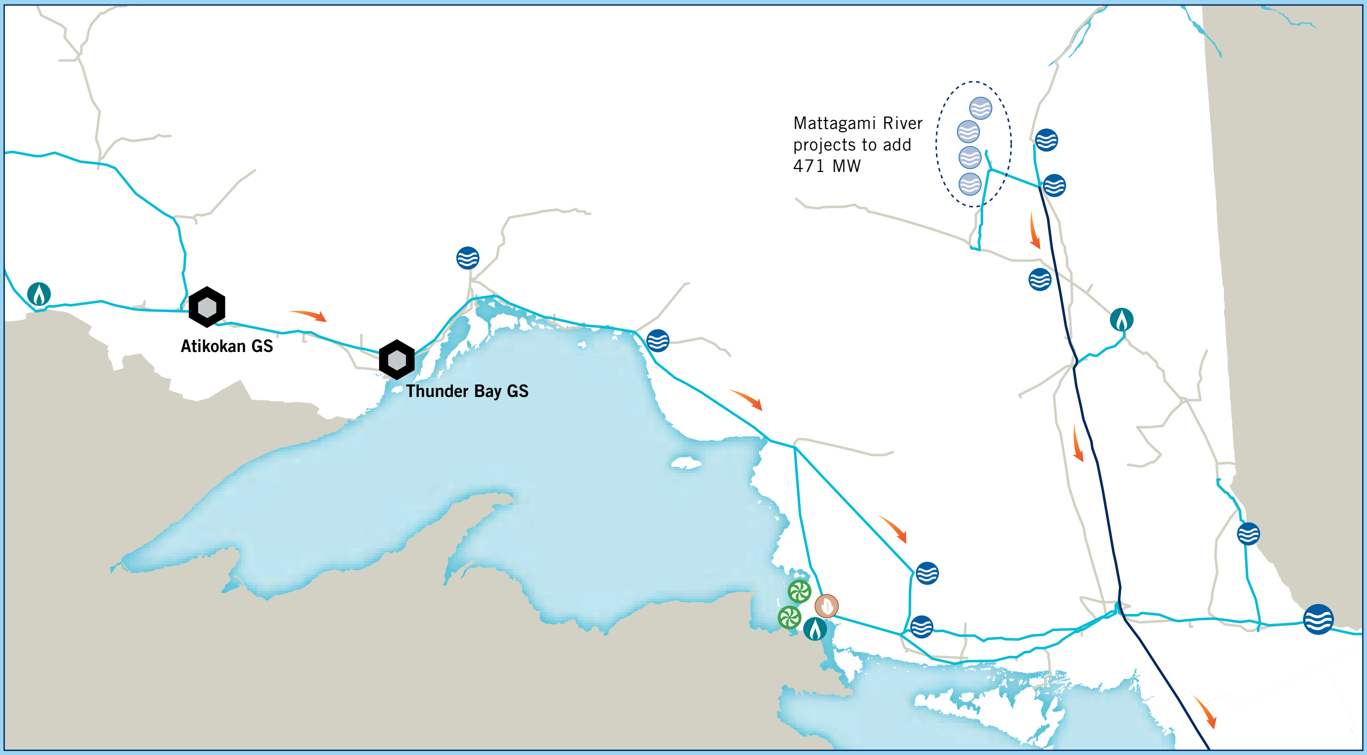


TABLE 3: REGIONAL REQUIREMENTS – PROJECTS CURRENTLY UNDER STUDY OR PROPOSED

AREA	RELIABILITY NEEDS IN THE AREA	EXPECTED/ REQUIRED BY	PROJECT(S) PROPOSED TO FULFILL REQUIREMENT
Central Toronto	Reduce transmission loading toward Central Toronto, and enhance supply to downtown	Summer 2008	Portlands Energy Centre
		Winter 2007-2008	John-Esplanade link
		Spring 2008	Interchange terminations of circuits C3L and C17L at Leaside Transformer Station (TS)
		Spring 2010	Build new 115 kilovolt (kV) circuit between Leaside and Birch Junction and reconfigure existing transmission
		Spring 2012	Build new TS and connect to John-Esplanade link
		Under review	Uprate transmission between Richview and Manby
		2011 to 2015	Install a third supply to downtown Toronto
GTA-West-GTA	Accommodate higher short circuit levels at Claireville TS to allow increased West GTA generation	Fall 2009	Replace 230 kV breakers, and reconfigure line terminations to allow split bus operation
			Terminate V75R at Richview TS
	Improve supply for Vaughan and Richmond Hill loads and allow additional stations	Under review	Install breakers in Claireville to Parkway corridor on circuits V71RP and V75P
	Improve voltage control in the west GTA	Spring 2007	Install additional shunt capacitors at Halton, Meadowvale TS
		Under review	Investigate effectiveness and feasibility of capacitor at Hamilton Beach TS
	Improve the reliability of Cherrywood TS	Winter 2009-2010	A new 500 kV breaker and diameter positions at Cherrywood and Claireville
			Re-arrange 500 kV line termination at Cherrywood
	Improve supply to north Mississauga and Brampton loads	Spring 2009	Establish Hurontario Switching Station (SS) on circuits R19T and R21T and extend and connect circuits V72R and V73R from Cardiff TS
			Install new underground cables line from Hurontario SS to Jim Yarrow
		2008	Build new transformer station next to Pleasant TS
		Spring 2013	Uprate 230 kV line between Hurontario SS and Pleasant TS
York Region: Newmarket-Aurora Area	Load growth exceeding the local transformer station capability	2006-2008	Additional reactive support
			New Holland Junction TS (OPA recommendation)
	Local growth exceeding capability of existing circuits	2011 or later	Additional TS at Aurora or Gormley, depending on the location and amount of local generation procured
Kitchener- Waterloo-Cambridge- Guelph and Orangeville Area	Local transmission enhancements required to relieve overloads and improve voltages	Fall 2007	Single 230/115 kV auto-transformer at Cambridge-Preston TS
		Fall 2008 to 2011	New supply connections and transmission reinforcements may be required to supply the growing load in the area
Burlington TS-Brant-ford-Woodstock	Loading on the auto-transformers near the maximum ratings	2008	Install over-current protections (planned for December 2007)
			Replace limiting connections and buswork to increase the limited-time thermal ratings and replace limiting transformer
	115 kV supply to Woodstock-Brant expected to be overloaded	Spring 2010	Install shunt capacitors at Woodstock TS (December 2007)
			Extend 230 kV tap from Ingersoll to a new 230/115 kV transformer station to supply Woodstock and Toyota load
Barrie-Stayner	Improve reliability to local loads	Summer 2007	Re-terminate circuits M5E and E27 on to new busbar positions
		Spring 2009	Replace existing Essa to Stayner 115 kV circuit with 230 kV double-circuit line
			Convert Stayner to 230 kV DESN
			Add 230/115 kV auto-transformer to supply Meaford TS
Eastern Ontario	Increase power transfer capability between Ontario and Quebec	2009	1,250 MW Ontario-Quebec high voltage direct current (HVdc) connection and shunt capacitors at Hawthorne TS
			New special protection systems at Hawthorne and St. Lawrence
			Uprate 230 kV circuits between Hawthorne and Merivale
	Enhance the supply to loads in the Oshawa and Belleville Areas	2010-2011	Relief of the 230 kV transmission east from Cherrywood is required to avoid overloads
			Investigate a connection to the 500 kV system

TABLE 3: CONTINUED

AREA	RELIABILITY NEEDS IN THE AREA	EXPECTED/ REQUIRED BY	PROJECT(S) PROPOSED TO FULFILL REQUIREMENT
Bruce Complex	Ensure system has sufficient reactive capability to enable return-to-service of Bruce Power Units 1 and 2 and retire the Nanticoke units	Dependent on timetable for retiring Nanticoke	Requirement for additional dynamic var facilities such as static var compensators (SVC) and/or synchronous condensers
		Fall 2007	High voltage shunt capacitors at Detweiler and Orangeville
	Transmission enhancements required to allow increased power transfers to enable return-to-service of Bruce Power Units 1 and 2	Spring 2007 to spring 2009	Additional shunt capacitors in southwestern Ontario (possible locations are Middleport, Buchanan and Nanticoke)
		2010	Series capacitors on the 500 kV circuits associated with the Bruce Complex (this option is under review)
	Transmission enhancements required to enable operation of 8 units at the Bruce complex	Spring 2009	Uprate sections of 230 kV Bruce to Orangeville circuits to allow increased output from Bruce
		Winter 2011-2012	Proposed additional 500 kV transmission line from the Bruce area toward the GTA
Sarnia-Windsor Area	Enhancements to enable additional generation in the area resulting from Clean Energy Supply (CES) contracts	Fall 2007	Reconfigure the terminations at Lambton SS to accommodate split bus operation to limit short circuit level
	Windsor area enhancements to address adequacy of supply to Kingsville and Leamington, improve security of supply to the City of Windsor and reduce operational restrictions of generation in the Windsor area	Fall 2007	Re-terminate two of the connections at Essex TS
			Expand the existing special protection system so that additional post-contingency responses can be initiated
			Replace existing 115/27.6 kV DESN station at Essex TS
		2010	Provide transmission reinforcements and/or local generation additions in the Windsor/Essex area
	Enable additional power transfer over the J5D Interconnection with Michigan	Under review	Assess the feasibility of uprating the 230 kV line to allow transfers from Michigan to Ontario over the J5D Interconnection to be increased by at least 200 MW
Niagara Area	Increase import capability on Queenston Flow West (QFW)	Originally scheduled June 2006 (delayed)	Install two new 230 kV circuits between Allanburg TS and Middleport TS and reinforce the 230 kV transmission facilities into Burlington TS
	Relieve limitations on the autotransformer	Spring 2009	Bus uprating at Allanburg TS
		Spring 2008	Circuit uprate in the St. Catharines area to increase load meeting capability
Northeastern Ontario	Enhance the Special Protection Systems	Summer 2007	Enhancements to existing generation rejection scheme in the northeast and additional breaker at Porcupine TS
	To expand the north to south transfer capability and reduce restrictions on northern resources.	Spring 2010	Install series capacitors at Nobel SS to increase north to south transfer capability
	Transmission enhancements to enable Mattagami expansion and other committed renewable generation developments in the northeast	Spring 2010	Additional transfer capability and voltage control north of Sudbury to accommodate the increased generating capacity
			Effectiveness of combinations of series capacitors with SVCs and shunt capacitors to be investigated
	To expand transfer capability east of Mississagi	2010	New SVC at Mississagi and shunt capacitor at Alogoma
			New special protection system (2009) will replace the existing one and provide additional functionality
	Existing 115 kV switchgear at Abitibi Canyon GS is at end-of-life	2009	New switchgear should be consolidated at a new 115 kV busbar at Pinard TS
			Arrangement would also provide a suitable location for a future 230/115 kV auto-transformer to reinforce the existing connection between the local 230 kV and 115 kV systems
Northwestern Ontario	Improve voltage control	2009	Repair existing capacitor at Fort Frances
			Install new shunt capacitor to coincide with retirement of Atikokan
			Replace failed synchronous condenser at Lakehead with an SVC
	Increase import capability from Manitoba to 400 MW	Under review	Accommodate new transformers and expanded 230 kV bus at Whiteshell
			Enhance voltage control with SVCs at Fort Frances TS, Mackenzie TS and Marathon TS, and shunt capacitors at Dryden TS

Local greenhouses in the Leamington area help reliability in Ontario by using backup generators managed by Genset Resource Management to satisfy their electricity needs when called upon by the IESO.

CONSERVATION AND DEMAND MANAGEMENT

All consumers in the province, from industrial to residential electricity consumers, can play a significant role in addressing part of Ontario's reliability needs. As businesses and homeowners become more conscious of their electricity use and become aware of opportunities to reduce and shift use away from peak demand periods, the reliability of the overall electricity system improves. In fact, the government has identified CDM as important components of its long-term plan for securing Ontario's electricity system.

The Ontario government has set aggressive CDM targets of 1,350 MW by 2007 and a further 1,350 MW by 2010.

The IESO, the Conservation Bureau of the OPA and LDCs have introduced a number of programs which encourage business owners and residential electricity customers to adopt energy efficiency measures and engage in demand response activities.

The IESO and the OPA operate demand response programs, which facilitate price responsive behaviour by customers. In such programs, customers that pay the hourly spot price for electricity have the option to reduce consumption when they foresee high electricity prices. Once customers make the commitment to reduce their consumption in approaching hours, the IESO may consider this demand reduction in its upcoming demand forecasts and dispatch decisions.

The first of the OPA's formal demand response programs, DR I, is essentially a permanent extension of the IESO's Transitional Demand Response Program (TDRP). The TDRP, which expires in April 2007, was established as a transitional program that provides incentive payments to fund the installation of demand response technologies and infrastructure. Launched on June 23, 2006, DR I is a permanent fixture that provides financial incentives to customers that are willing to provide demand response capacity during high priced periods and system emergencies.

Phases two and three of the OPA's demand response program are expected to be implemented later this year. DR II is a load shifting program that provides financial incentives to shift demand to non-peak periods of the day. Under the third program, DR III, participants will be notified of specific demand response events and will be expected to shed load as defined under their contract.

As the CDM programs grow and results are verified, the IESO will integrate the demand response capacity procured through these programs in its reliability forecasts.

The IESO is currently working with the OPA to determine how demand response capacity that has been contracted under its programs can be integrated into the IESO's demand forecasts and system operations.

The system operational benefits of demand response programs are dependent upon a number of factors including:

- The resource must be available when and where needed for reliability;
- The resource operation must be visible and predictable to the IESO; and
- The efficient dispatch of other resources is not compromised.

The OPA will be establishing a portfolio of standard CDM programs aimed at residential and other low volume customers that can be implemented throughout the province. Three programs that the OPA has committed to expand province-wide include the appliance retirement program, the Summer Challenge energy reduction program and a residential load control program aimed at reducing the summer peak demand. LDCs are also actively developing and delivering a number of CDM programs.

Another element of the government's provincial CDM strategy is its smart meter initiative. The Ontario government has committed to installing 800,000 smart meters throughout the province by the end of 2007, and for all Ontario customers by the end of 2010. Because smart meters can measure electricity consumption on an hourly basis, they will provide Ontario customers with valuable information about their usage patterns. With greater understanding of how and when they use electricity, customers will be able to take actions to better manage their costs. In addition, providing more customers with the knowledge and opportunity to respond to pricing signals furthers the efficiency of the electricity market.

From the perspective of system operation, smart meters should encourage customers to curb energy use during peak periods, which in turn reduces the strain on the electricity system and could potentially defer the need to build new and expensive peaking generation. The success of this measure is, in part, dependent on providing consumers with timely information, in sufficient detail, for them to manage their energy use.

As the reliability coordinator, the IESO remains concerned with ensuring that demand response capacity is available when and where it is needed most. Some of the programs and initiatives described above are voluntary in nature and as such there is a risk that the associated benefits may not materialize in real-time or in the affected area. As CDM measures become more prominent, the IESO will closely monitor their contribution during peak demand and extreme weather events in order to reliably and efficiently schedule resources and operate the system.

Reducing peak demand will help contribute to the reliability of the system. The IESO recognizes that some investments in CDM can take longer to have a meaningful impact than conventional investments in generation and transmission infrastructure. As discussed earlier, the forecast supply situation will help address any delays in achieving CDM savings. Effective conservation and demand management measures require significant education and cultural shifts, which the IESO, the OPA, LDCs and the Ministry of Energy are encouraging through their respective programs.

For a list of the expected conservation and demand management savings, please see Table 2 on page 7.

INDUSTRIAL CUSTOMERS CONTRIBUTE TO RELIABILITY

There are a number of large industrial customers that regularly change their level of electricity consumption according to market prices without participating in any formal incentive-based programs offered by the OPA or the IESO. Some of these customers participate directly in the wholesale electricity market by making hourly bids to buy electricity. If the market price exceeds their bid price, they are instructed to stop consuming electricity. By participating directly in the market, these customers, known as dispatchable loads, will only pay up to what they consider to be the true value of electricity to them. If the cost is too high, they will shift their consumption to lower priced periods or operate on-site back-up generators.

A significant benefit of dispatchable loads is that they are an additional source of operating reserve supply. Operating reserve is stand-by capacity that is kept on-line in case the power system suffers a severe strain and reserve power is required. Dispatchable loads can serve as operating reserve because they can be instructed to stop consuming when the system is strained. The availability of dispatchable loads to serve as operating reserve tends to reduce energy and operating reserve prices and contribute to system reliability.

At the opening of the electricity market in 2002, there were only two large industrial customers registered as dispatchable loads. Today, there are nine, accounting for over 700 MW of directly connected price responsive load.

The availability of dispatchable load was notable when Ontario set records for peak demand during the summers of 2005 and 2006.

During the record setting days of July 2005 and August 2006, dispatchable loads contributed to maintaining the overall reliability of the Ontario system. Because dispatchable loads have the ability to respond quickly to dispatch instructions, the IESO was able to dispatch them down, thereby reducing demand and relieving some of the strain on the system.

In addition to these observations, the IESO's market assessment unit examined the consumption patterns of other large non-dispatchable industrial customers on August 1, 2006, to determine if any other customers reduced their electricity purchases in response to expectations of high demand and prices without specific instructions from the IESO.

The analysis revealed that four large industrial customers did in fact respond to the high price signals by reducing the amount of energy withdrawn from the system by a combined 25 MW for four hours. Their processes and systems remained unaffected as they were able to switch to their on-site back-up generators, which are typically uneconomic to operate.

The market price impact of the combined 25 MW load reduction was material. The market assessment unit estimates the price was almost one cent per kilowatt-hour lower as a result of the demand response of these customers.

A number of industries participate in the Ontario electricity market as dispatable loads.

INTERCONNECTED ELECTRICITY MARKETS

The Benefits of Being Interconnected

Ontario is part of a bigger North American electricity market which has been described in the past as the single largest machine ever built by humans. Ontario is interconnected with Manitoba, Quebec, New York, Minnesota and Michigan and through those jurisdictions, other provinces and states. Among all of its interconnections, Ontario has the ability to import and export between 4,000 MW and 5,000 MW.

Ontario benefits from its interconnections from both an economic and reliability perspective. First, when prices are less expensive in neighbouring jurisdictions than generation in Ontario, imports reduce the price to Ontario consumers from what it otherwise would have been. In addition, Ontario generators are able to export surplus capacity which contributes to the recovery of their fixed costs.

Being interconnected allows Ontario to achieve a level of reliability that would otherwise require a significantly greater amount of installed generating capacity, and associated higher costs. Under tight supply conditions, such as those experienced during the summers of 2002 and 2005, Ontario was able to attract imports at unprecedented levels to help maintain reliability in the province. In addition, the ability to export excess output provides generators with more demand certainty. As a result, they are more likely to ramp up in the morning and remain on-line during the day, which has significant reliability benefits for Ontario.

Longer-term Ontario may not be able to continue to rely on the same level of support from its interconnected neighbours as it has received in the past. Surrounding jurisdictions continue to meet their resource adequacy requirements, but as their load grows, they are beginning to face the prospect of declining supply margins.

According to the North American Electric Reliability Corporation's (NERC) 2006 Long-Term Reliability Assessment, there is expected to be a general decline in reserve margins over the next decade, including in those areas directly connected with Ontario. Although the benefits of being interconnected continue to exist, this decline will serve to reduce Ontario's confidence in imports.

Ontario's Improved Supply Picture

Fortunately Ontario can count on more domestic supply than it has in recent years. Since the market opened in May 2002 approximately 4,400 MW of new and refurbished supply has come on-line in Ontario. Over the same period, the 1,200 MW Lakeview coal-fired generating station in Mississauga was shut down, resulting in a reduction in emissions.

The improved supply situation is underscored by the fact that in 2006, Ontario was a net exporter for the first time since 2000. Last year, Ontario imported just over six terawatt hours (TWh) of energy from its neighbours while exporting almost double that amount.

There are also other indications of the improvement in Ontario's supply picture since May 2002.

In addition to having enough supply to meet demand, Ontario is required to carry an operating reserve to protect against contingencies and changing conditions. Since market opening, the number of hours when the required operating reserve plus demand exceeds the available domestic capacity has decreased substantially. In fact, operating reserve plus Ontario demand exceeded available domestic capacity in just 246 hours in 2006 compared to 622 hours in 2003.

Both planned and forced outage rates for Ontario's nuclear and fossil fleets have declined over the past four years, declining by seven per cent since the summer of 2003. This improved performance is influenced by the competitive and transparent environment in which generators operate today as compared to before market opening. It reflects, in part, the operating risks that generators bear and the need to operate to recover their costs and earn a rate of return.

ONTARIO AND ITS INTERCONNECTED MARKETS

Transmission Limits In to and Out of Ontario*

Manitoba	In to Ontario	Out of Ontario
summer	331 MW	263 MW
winter	343 MW	275 MW

Minnesota	In to Ontario	Out of Ontario
summer/winter	90 MW	140 MW

Michigan	In to Ontario	Out of Ontario
summer	1,550 MW	2,150 MW
winter	1,800 MW	2,400 MW

New York Niagara	In to Ontario	Out of Ontario
summer	1,300 MW	1,300 MW
winter	1,650 MW	1,950 MW

New York St. Lawrence	In to Ontario	Out of Ontario
summer/winter	400 MW	400 MW

Quebec North	In to Ontario	Out of Ontario
summer	65 MW	95 MW
winter	84 MW	110 MW

Quebec South (East)	In to Ontario	Out of Ontario
summer	800 MW	420 MW
winter	800 MW	470 MW

Quebec South (Ottawa)	In to Ontario	Out of Ontario
summer	748 MW	147 MW
winter	748 MW	167 MW

* As of December 2006. Actual transfer capability will vary depending on current system conditions.

Market Evolution

The IESO has been working to evolve the electricity market to encourage reliable supply and improve economic efficiency.

In 2006, the IESO responded to a variety of operational and stakeholder concerns by placing its highest priority on resolving immediate reliability based market issues before proceeding with significant market evolution programs.

Consequently, the first half of 2006 was focused on the implementation of the DACP, day-ahead and real-time intertie failure charges and the development and implementation of the ELRP.

These initiatives contributed favourably to the reliable operation of Ontario's power system during the record setting days of early August 2006. Overall, these initiatives resulted in greater certainty of generator availability, fewer transaction failures and additional flexibility for the IESO in managing the reliability of the system.

As it matures, the market will help to encourage investment in the Ontario electricity system, facilitate competition in the generation and sale of electricity, and drive innovation. Market-based rates will promote more informed consumption decisions, including energy efficiency, time-of-use management, conservation, and the development of distributed and renewable generating facilities.

All the while, the market must evolve in a manner that permits Ontario to benefit from the interconnected markets. This can best be achieved by pursuing designs that are consistent, or at a minimum, compatible with surrounding jurisdictions. Current design inconsistencies, including price calculation differences and the lack of a day-ahead market in Ontario continue to present challenges for importing and exporting electricity in the most efficient manner.

Over the coming months and years, the IESO will be working on a number of new market initiatives with the OPA, including long-term forward contracting and the development of load serving entities (LSE). The primary focus for the IESO in 2007 will be to assess the benefits, costs and viability of a day-ahead market in Ontario.

The development of LSEs is an important initiative that is currently being tested by the OPA through pilot programs. Generally, LSEs would have responsibility for sourcing electricity supply for default electricity customers, who, in the case of Ontario, are customers under the Ontario Energy Board's (OEB) Regulated Price Plan (RPP). The current environment where both RPP consumers and some other consumers are not actively represented in the market insulates a considerable portion of the load from market drivers. Development of LSEs can help address that. The pilot programs underway will provide valuable learning for Ontario by examining procurement, pricing, implementation and settlement issues around long-term LSE development.

In other jurisdictions, a day-ahead market enables participants to lock into prices one day in advance of real-time energy delivery if they so desire. This provides more certainty to suppliers and consumers, allowing them to react to price by leveraging added flexibility they may have a day in advance that is just not possible to take advantage of in real time. The added certainty and flexibility of day-ahead planning by more market participants is expected to improve the overall efficiency of the market and improve reliability. Stakeholder discussions about the development of enhanced day-ahead arrangements that make the most sense at this time for Ontario are continuing.

OTHER CONCERNS

A number of developments have occurred since the release of the previous Ontario Reliability Outlook in June. These new developments, in addition to previously identified concerns which still require action, are highlighted below.

25 Hertz System

The vast majority of Ontario's electricity system operates at a frequency of 60 Hertz (Hz), however two small pockets remain where generation and, in one case, load remain in operation at 25Hz, a carryover from 60 years ago when Ontario operated at this frequency.

Near Niagara Falls, a relatively small amount of load (approximately 50 MW) and generation (approximately 100 MW) continue to operate within the Niagara 25 Hz sub-system. The two remaining customers on this system are serviced by Ontario Power Generation's (OPG) Sir Adam Beck 1 Units 1 and 2 and OPG's 25 Hz frequency changer, FC1.

It has become increasingly difficult and expensive to maintain the reliability of this sub-system due to the age of the generation, transmission and distribution facilities and the obsolescence of 25 Hz equipment. Since 2003, the IESO has been working with all concerned parties to arrive at a retirement plan for the 25 Hz system at Niagara in order to eliminate significant inefficiencies identified by the Market Surveillance Panel in their July 2003 report. In June 2005, the IESO advised stakeholders to plan for the retirement of these facilities by April 2009 and to make arrangements for connection to the more reliable and efficient 60 Hz system.

National Grid in New York State has recently retired the US portion of the Niagara 25 Hz system earlier than their scheduled date of December 31, 2007. Late in 2006, OPG applied to the IESO to de-register its 25 Hz equipment at the Sir Adam Beck 1 Generation Station by April 2009.

Phasing out the Niagara 25 Hz system will eliminate the inefficiencies associated with the 25 Hz generation and transmission facilities. By converting their facilities to the standard 60 Hz system, the affected customers will align themselves with the rest of the Ontario system, which will enhance the reliability and stability of their supply needs. The IESO is working closely with these customers and other stakeholders to ensure that conversion to the 60 Hz system is well coordinated.

In northeastern Ontario, three small 25 Hz hydroelectric generation stations, totalling about 20 MW, continue to operate at 25 Hz, delivering power to the grid through frequency changers located near Sudbury. All 25 Hz loads in this area have long been converted to 60 Hz. Plans are underway to remove these stations from service in 2007 and 2008, convert them to 60 Hz operation and restore them to service by late 2008 into 2009. Once converted, the generation output will be increased to about 35 MW.

Lennox Reliability-Must-Run Contract

Since 2005, OPG has annually requested permission to remove Lennox generating station from service because market revenues are insufficient to cover its operating costs. Lennox, a 2,100 MW dual-fuel (natural gas and oil) facility, is located just west of Kingston and is an important source of supply in the region east of Toronto. Studies undertaken by the IESO to determine the impact of removing Lennox from service conclude that all four units at Lennox are necessary for maintaining reliability in the region at least until new transmission enhancements in the Ottawa area and new generating resources in the Toronto area are in-service.

To offset the revenue deficit and maintain Lennox in-service, the IESO and OPG have entered into reliability-must–run (RMR) contracts, which guarantee that OPG will recover the costs of running the facility as long as it is continued to be made available to the Ontario electricity market. As required by OPG's license conditions, these contracts have been approved by the OEB.

The IESO has recently received another application from OPG for permission to remove Lennox from service, as the current RMR contract expires later this year. Even when current local area requirements are addressed, the capability of the station is critical to provincial resource adequacy and must be retained or replaced to satisfy that requirement. This resource adequacy requirement cannot be achieved through an RMR under the current Market Rules. The OPA has notified the IESO that it will undertake development of a solution to the Lennox requirements.

Approvals Process

The IESO remains concerned about the impact of the current approvals processes on the ability to achieve the timely implementation of generation and transmission projects. This issue was first raised in the February, 2006, Ontario Reliability Outlook.

In the meantime, a number of projects awarded contracts under the Renewable Energy Supply and Clean Energy Supply Requests for Proposals have been delayed by various municipal permitting or environmental screening requirements. Of particular concern in these cases has been the open-ended nature of the appeals process which does not provide time-certainty to the decisions.

While some changes have been made, there will continue to be a risk that projects will not be available when needed because of uncertainties and timelines under local and environmental approvals.

The potential impacts of the current approvals process on planned projects will need to be continually evaluated to determine whether other decisions affecting planned or existing facilities are required to maintain reliability.

CONCLUSIONS AND RECOMMENDATIONS

- The reliability outlook for Ontario's power system has improved since June, 2006, as a result of actions to bring into service 7,000 MW of new or refurbished supply by 2011 and by the decision to have the OPA and IESO jointly develop a coal transition plan. This improved outlook reflects both overall resource adequacy as well as a number of local areas where supply concerns are now being addressed.
- A number of transmission enhancements are required to accommodate the planned new and refurbished supply and address local reliability needs. Otherwise, a number of transmission facilities in Ontario will be operated near their maximum capability, with little margin for unexpected events and requiring complex arrangements to do routine maintenance on critical facilities.
- The IESO remains concerned about the uncertainty around the length of approvals processes affecting generation and transmission projects and the impact on the timing of the implementation of the projects. Until the approvals process is demonstrated to be effective, there will continue to be a risk that projects will not be available when required.
- There is a need to ensure that the future supply and demand response mix has sufficient generation that can be dispatched up or down to match changes in the level of demand. These load following requirements are critical during early morning hours, when demand climbs quickly and in the evening when demand begins to decline.
- Aggressive targets have been set in the near future for CDM. Reducing peak demand will help contribute to the reliability of the system. Ontario's improved supply situation will help address any delays in achieving CDM savings. As CDM results are verified, the IESO will integrate the demand response capacity in its reliability forecasts.
- The planned installation of 4.5 million smart meters over the next four years combined with prices that reflect time of use can provide customers with an opportunity to curb their use of electricity during peak periods. Customer education efforts, and the provision of timely information in sufficient detail, will increase the demand response capability offered through smart meters.

THE ONTARIO RELIABILITY OUTLOOK IS ISSUED SEMI-ANNUALLY BY THE INDEPENDENT ELECTRICITY SYSTEM OPERATOR (IESO) TO REPORT ON PROGRESS OF THE INTER-RELATED GENERATION, TRANSMISSION AND DEMAND MANAGEMENT PROJECTS UNDERWAY TO MEET FUTURE RELIABILITY REQUIREMENTS.

Power to Ontario. On Demand.

Independent Electricity System Operator
655 Bay Street, Suite 410
P.O. Box 1
Toronto, Ontario M5G 2K4
Reception: 905.855.6100
Media inquiries: 416.506.2823

IESO Customer Relations
Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

The Independent Electricity System Operator (IESO) manages the province's power system so that Ontarians receive power when and where they need it. It does this by balancing demand for electricity against available supply through the wholesale market and directing the flow of electricity across the transmission system.

ONTARIO POWER AUTHORITY

MATERIALS

Appendix 1	OPA Analysis of Need for Proposed Facilities
Appendix 2	OPA Letter to Hydro One dated December 22, 2006
Appendix 3	Hydro One response to OPA Letter dated January 17, 2007
Appendix 4	OPA Letter to Hydro One dated March 23, 2007
Appendix 5	Transmission Discussion Paper No. 5
Appendix 6	Integration Discussion Paper No.7
Appendix 7	Minister's June 13, 2006 Directive to OPA on IPSP Goals
Appendix 8	Minister's November 7, 2005 Directive to OPA on RES I contracts
Appendix 9	Minister's November 16, 2005 Directive to OPA on RES II contracts
Appendix 10	Schedule of OPA Contracts for Bruce Area Wind Projects under RES I and II
Appendix 11	Minister's March 21, 2006 Directive to OPA on Renewable Standard Offer Program
Appendix 12	Minister's October 14, 2005 Directive to OPA on Bruce Units 1 and 2 Refurbishment
Appendix 13	Provincial Land Use Policy

APPENDIX 1

OPA Analysis of Need for Proposed Facilities.

Appendix 1

OPA ANALYSIS OF NEED FOR PROPOSED FACILITIES

1.0 BACKGROUND

Under the *Electricity Act, 1998* (the "Act"), the OPA has the responsibility for long-term power system planning in Ontario. In accordance with the Act, the OPA is required to periodically develop an Integrated Power System Plan (IPSP). In developing the IPSP, the OPA must follow directives issued by the Minister of Energy setting out goals to be achieved during the period covered by the plan.

The Minister of Energy issued a directive to the OPA dated June 13, 2006, setting goals that the OPA must plan to meet in its first IPSP. These include the goal of increasing the installed capacity of renewable energy sources by 2,700 MW from the 2003 base by 2010 and increasing "the total capacity of renewable energy sources used in Ontario to 15,700 MW by 2025". The directive further requires the OPA to plan to strengthen the transmission system in order to:

- Enable the achievement of the supply mix goals set out in this directive;
- Facilitate the development and use of renewable energy resources such as wind power, hydroelectric power and biomass in parts of the Province where the most significant development opportunities exist;
- Promote system efficiency and congestion reduction and facilitate the integration of new supply, all in a manner consistent with the need to cost-effectively maintain system reliability.

Consistent with its policy direction, the Government of Ontario also undertook the Renewable Energy Supply procurements (RES I and II), which led to the execution of several contracts for wind projects in the Bruce area. By a directive dated November 7, 2005 (found at Exhibit B, Tab 6, Schedule 5, Appendix 8), the OPA was directed to assume the responsibilities of the Crown under the contracts entered into as a result of the RES I procurement process. By a directive dated November 16, 2005 (found at Exhibit B, Tab 6, Schedule 5, Appendix 9), the OPA was directed to enter into contracts with the proponents selected under the RES II procurement process. A schedule of the contracts with the OPA for wind projects in the Bruce area that resulted from the RES I and II procurement processes is found at Exhibit B, Tab 6, Schedule 5, Appendix 10.

Further, the Minister of Energy issued a directive to the OPA dated March 21, 2006 (found at Exhibit B, Tab 6, Schedule 5, Appendix 11) to develop a standard offer program for renewable energy projects in the Province. The OPA has commenced the implementation of this program; but in light of the system constraints in the Bruce area, the OPA has decided to not issue contracts for developments in this area until there is sufficient transmission capacity available or there are other means to manage the limited transmission capacity.

The Government of Ontario also negotiated an agreement with Bruce Power for the refurbishment and return to service of two idle nuclear units, Unit 1 and Unit 2, at the Bruce A plant, the purchase of the power from these units, and the further refurbishment of Units 3 and 4 at Bruce A. The Minister of Energy issued a directive to the OPA dated October 14, 2005 (found at Exhibit B, Tab 6, Schedule 5, Appendix 12) to execute this contract.

The proposed Bruce to Milton transmission reinforcement project will help to achieve the Government policy goals and enable the fulfillment of the aforementioned resource development commitments in the Bruce area that were initiated by the Government prior to the development of the IPSP.

The availability of the committed resources in the Bruce area and the means to deliver those resources to the Ontario power grid is an underlying assumption in the development of the IPSP. Beyond the existing and committed resources in the area, the assessment done to date for the IPSP has identified significant potential, about 1000 MW, for further renewable energy resource development in the Bruce area. Developing this potential, which would be facilitated by the proposed project, will contribute to meeting the Government's renewable energy resource target.

2.0 NEED FOR THE PROJECT

2.1 Classification of Need

The OEB's Filing Requirements for Transmission and Distribution Applications (EB-2006-0170) provide in section 5.2 for transmission projects proposed in an application under section 92 of the *Ontario Energy Board Act* prior to the approval of an Integrated Power System Plan, to be categorized first into Development, Connection or Sustainment. In this case, the project is a development project because the proposed facilities provide for additional system capacity and maintain reliability and quality of electricity supply.

Once this first categorization is complete, the project must then be categorized as either a non-discretionary or discretionary project. A non-discretionary project is described as a "must do" project, the need for which is determined beyond the control of the Applicant. This project is considered to be non-discretionary because the proposed facilities are needed to achieve objectives of the Government of Ontario that are prescribed in the directives referred to in Section 1 – Background.

2.2 Project Need

As detailed in Section 1 – Background, about 1,500 MW of nuclear and 675 MW of wind generation capacity was contracted for in the Bruce area in the past three years. In addition, there are 15 MW of wind generation already in operation and 10 MW contracted from the Renewable Energy Standard Offer Program. These resources contribute to meeting the Government's electricity policy objectives. With these resources, the OPA estimates that the total generation available in the Bruce area will total about 5,800 MW by 2009 and 7,300 MW by 2012. With the additional wind generation opportunities of about 1,000 MW also identified by the OPA in the area, the total generation in the Bruce area could reach 8,300 MW by the middle of the next decade.

As indicated in the OPA's IPSP discussion papers (see Exhibit B, Tab 6, Schedule 5, Appendices 5 and 6), the present transmission system has the capability to transmit about 5,000 MW of the generation from the Bruce area. This capability is established by the IESO in setting its operating limits.

Hydro One, as set out in its Transmission Licence, must comply with the technical and performance requirements of the Transmission System Code ("TSC") and various regulatory bodies, including the Northeastern Power Coordinating Council ("NPCC") and the North American Electric Reliability Council ("NERC"). These requirements include the duties of maintaining acceptable voltages, keeping equipment operating within established ratings, and maintaining system stability, both during normal operation and under recognized contingency conditions on the transmission system.

Based on these requirements, the shortfall in transmission capacity as related to the available resource in the Bruce area is forecast to be about 800 MW by 2009 and 2,300 MW by 2012, and could well be over 3,300 MW afterward should the renewable energy potential continue to develop in the area. Given the expected shortfall between transmission capability and forecast available generating capacity in the Bruce area, there is a need to reinforce the transmission system out of the Bruce area as early as possible both to permit full deployment of the committed generating resources and to enable the development of potential new renewable energy resources in the Bruce area consistent with Government policies and directives.

The OPA's conclusions are supported by the IESO. In its June 2006 Ontario Reliability Outlook and its System Impact Assessment (SIA) for the proposed facilities, the IESO identified the need for reinforcement of the transmission system in order to effectively extract the committed and proposed additional generation capacity from the Bruce area and to maintain reliable performance of the transmission system consistent with applicable reliability planning standards and guidelines. The SIA also confirms that the proposed facilities would be adequate to meet the applicable reliability standards and guidelines and will not adversely impact the IESO-controlled grid. The SIA is filed hereto as Exhibit B, Tab 6, Schedule 2.

APPENDIX 2

OPA Letter to Hydro One dated December 22, 2006

RECEIVED
JAN 2 2007

Ontario Power Authority

December 22, 2006

Ms. Laura Formusa
Acting CEO, Hydro One
483 Bay Street
Toronto, ON
M5G 2C9

Mr. Paul Murphy
CEO, IESO
Station A, Box 4474
Toronto, ON
M5W 4E5

Mr. Duncan Hawthorne
President & CEO, Bruce Power
177 Tie Road
PO Box 3000, B0602
Tiverton, ON
N0G 2T0

Dear Sirs/Madam:

Re: Transmission from Bruce Area

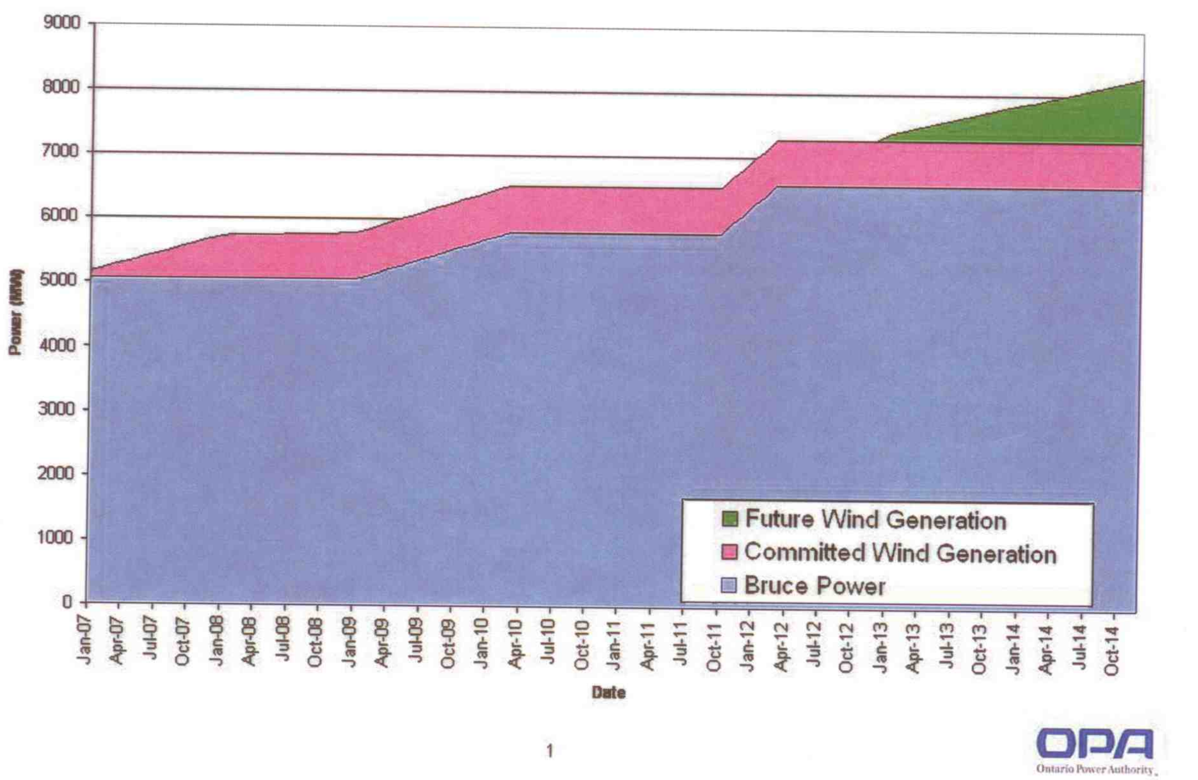
The OPA is writing, in keeping with its mandate to plan the electricity system in Ontario and support the goal of ensuring adequate, reliable and secure electricity supply in Ontario, to bring a matter of concern to the OPA to your attention. The OPA believes that action must be urgently taken to ensure that there is adequate system capacity to permit all available generation in the Bruce area to be transmitted. The OPA's analysis of this matter is found in section 2.3.6 of the OPA's Discussion Paper 5 on Transmission, issued as part of OPA's stakeholder process on the IPSP. This Paper was released on November 13, 2006 and was discussed as part of a workshop on the IPSP held by the OPA on November 22-24, 2006.

Summary of OPA Analysis:

As you are aware, Bruce Power is refurbishing and returning to service the two "laid-up" generating units, Units 1 and 2, at the Bruce A nuclear plant. These units, each rated at 725 MW, are scheduled to be returned to service in 2009. They will add 1450 MW of base load generation to the Ontario system, which will improve the province's reliability of supply. Coincidental to the return of the two Bruce units, Bruce Power is scheduling the outage of other units at the Bruce A plant for extended maintenance work from 2009 to 2011. Thus, in effect, an equivalent of one Bruce unit is added between 2009 and the end of 2011, and two units thereafter.

Additionally, about 725 MW of wind generation has been committed for the Bruce area. Our latest studies done for preparation of the Integrated Power System Plan identifies a potential for another 1000 MW or more of wind generation that could be developed in this area. Together, these new resources add to about 1500 MW by 2009, about 2250 MW by 2012, and over 3000 MW in the longer term. The generation increases in the Bruce area between now and 2012, and the possible amount to 2014 are shown in Figure 1.

Figure 1 - Bruce Area Generation



The existing transmission system that transmits power from the Bruce area to the Greater Toronto Area (GTA) was last expanded around 1990 and has sufficient capacity for the existing generation there now, namely 4 units at Bruce B and two units at Bruce A, with a combined output of about 5060 MW. There is some additional capacity to incorporate the committed wind generation in the Bruce area once the critical sections of two of the Bruce 230 kV circuits, between Hanover and Orangeville, have been uprated and additional static or dynamic shunt reactive sources installed at the Middleport, Orangeville and Detweiler stations. OPA staff has discussed these system reinforcements with Hydro One and IESO staff. Hydro One is currently assessing the extent of the work required to uprate the 230 kV circuits. The OPA recommends that this uprating work should proceed immediately to enable an in-service date of mid 2009. The OPA also recommends that project development work for the addition of static or dynamic shunt reactive sources be commenced in accordance with any requirements that may be established by the IESO or the OPA.

As stated in the OPA's Transmission Discussion Paper #5, a new 500 kV line from the Bruce area to the GTA is required to address the long term transfer capability requirements out of the Bruce area. However, following the determination of the optimum route, expected approval timelines for a project of this magnitude will not enable the required in-service date of 2009 to be met. Therefore, further measures are required beyond the immediate transmission enhancements described above to bridge the two year gap between the return to service of the Bruce Units 1 and 2 in 2009 and the expected in-service date for the new 500 kV line of late 2011.

Staff of the OPA and the IESO have worked together in the past year to identify and assess interim measures for increasing the transfer capability between Bruce and the GTA. The interim measures that were found to be the most effective are:

- generation rejection (GR) of up to 1500 MW (two Bruce units or one Bruce unit and wind generation) and, subject to confirmation from the due diligence study noted below

- 30% series compensation of the Bruce to Longwood and Longwood to Nanticoke 500 kV circuits.

The IESO has assessed these interim measures. Their results show that the immediate enhancements combined with GR, which can be placed in service in 2009, will allow the output from seven Bruce units and committed wind generation to be transmitted. Thirty percent (30 %) series compensation may be used as a stop-gap measure to further expand transmission capability to accommodate eight Bruce units if approvals for the new 500 kV line are unduly delayed.

The interim measures are not alternatives to the long-term solution since they increase the risk to the security and reliability of the power system. The use of GR as an interim measure until a more permanent solution is in place is subject to NPCC approval. With regard to the use of series compensation, a new technology for Ontario, for increasing the transmission capability out of Bruce, Hydro One Networks has expressed concern regarding the system and equipment risks. The OPA appreciates this concern and will retain third party experts to undertake a due diligence study to assess the suitability and risks associated with the use of series compensation for this application. Staff of Hydro One Networks and the OPA have drafted a document that addresses the scope of technical issues and concerns to be covered by this study. The process to retain an appropriate consultant has commenced.

Conclusion:

We recommend that:

- Hydro One Networks proceeds as quickly as possible with the work to upgrade the Hanover x Orangeville 230 kV circuits and install static or dynamic shunt reactive sources as identified by the IESO or the OPA, and
- Hydro One Networks, IESO and Bruce Power proceed as quickly as possible with the work to install generation rejection for the Bruce generation.

Further, the OPA is committed to undertaking the due diligence study on series compensation as quickly as possible. OPA staff will attempt to assist you in providing any other information that you may require on these matters.

If you have any questions, I would be happy to discuss them with you.

acting for

Jan Carr
CEO, OPA

cc. Howard Wetston, Chair of OEB

APPENDIX 3

Hydro One response to OPA Letter dated January 17, 2007.

Hydro One Inc.
483 Bay Street
15th Floor North Tower
Toronto, Ontario M5G 2P5

Tel: (416) 345 6306
Fax:(416) 345 6056

Laura I. Formusa
President and Chief Executive Officer (Acting)

hydro One

1/22/07 JC

Chris Shelley
Mike Lyle
Paul Bradley

January 17, 2007

Mr. Jan Carr
Chief Executive Officer
Ontario Power Authority
120 Adelaide Street West, Suite 1600
Toronto, ON M5H 1T1

Dear Jan,

Re: Near Term and Interim Measures for Transmission out of Bruce

Thank you for your letter of December 22, 2006 summarizing the OPA's analysis that a new 500 kV line is required to increase transmission transfer capability from Bruce County to the Greater Toronto Area. Hydro One supports this conclusion and, upon receipt of the OPA's final determination on this matter, will seek necessary regulatory and environmental approvals to begin construction.

To expedite the project, consultations have been started with municipal and regional administrators to describe the need for, and nature of the 500 kV line construction. Hydro One and OPA staff have participated jointly in this process.

Hydro One agrees that the expected approval and construction timelines for the new 500 kV line will not meet the required in-service date of 2009. Based on the OPA's recommendations, Hydro One has allocated funding and commenced project development work on near term and interim measures to increase transfer capability until the line is constructed. These measures are summarized below:

(i) Uprating the 2-Circuit Hanover to Orangeville 230 kV Line

Engineering and design work to increase the emergency rating of the 2-circuit Hanover to Orangeville 230 kV line has commenced. We expect the OPA's recommended in-service date of mid 2009 will be met provided unforeseen circumstances do not arise.

(ii) Installation of Dynamic and Shunt Reactive Sources

Hydro One has initiated the generic work to install Static Var Compensation (SVCs) and shunt compensation in Southwestern Ontario. This work includes the preparation of equipment specifications and preliminary engineering. In order to carry out detailed engineering and design, more specific information is required with respect to the exact amount (MVAr) and location of the SVCs and shunt capacitors. I understand that this information is being determined through a joint team comprising staff from Hydro One, OPA and IESO.

As long as detailed requirements for reactive compensation are finalized before April 2007, Hydro One is reasonably confident that the required equipment can be delivered and placed in service by the end of 2009, as recommended by the OPA.

(iii) Modifications to Extend Generation Rejection (GR)

The initial asset condition assessment of Hydro One's part of the Bruce Special Protection System (BSPS), indicates that the required modifications (based on preliminary data from the IESO) are feasible. These modifications will enable up to 1,500 MW of generation to be rejected following specified contingencies. If the BSPS is required in the long term, there may be a need to replace its equipment due to technological obsolescence and aging of the electronic hardware and software.

Hydro One will begin implementing the required BSPS modifications once the final requirements are established by the IESO. We expect to meet the required 2009 in-service date providing these requirements are straightforward and do not prompt major modifications to, or replacement of the existing BSPS.

As indicated in your letter, BSPS modifications will also be required on Bruce Power equipment and possibly on equipment for wind generators in the Bruce area. Under the Market Rules, the IESO will coordinate and provide direction to affected generators to ensure they implement required modifications. Hydro One will provide support, as required, to enable its modifications to be coordinated with the generators' activities.

Regarding the need and feasibility of installing series compensation on the existing transmission out of Bruce, we will await further OPA direction pending the results of a due diligence study that is being undertaken by the OPA.

Finally, I'd like to reaffirm that Hydro One is committed to supporting the OPA as it develops various transmission solutions around the province, including transmission out of Bruce.

If you have any questions or concerns, please do not hesitate to let me know about them,

Yours truly,

Laura Formusa

Laura Formusa
President and CEO (Acting)
Hydro One Inc

Copy to: Mr. Paul Murphy
President and CEO, IESO

Mr. Duncan Hawthorne
President & CEO, Bruce Power

APPENDIX 4

OPA Letter to Hydro One dated March 23, 2007

OPA
Ontario Power Authority

Suite 1600
Toronto, Ontario M5H 1T1
T 416-967-7474
F 416-967-1947
www.powerauthority.on.ca

THE OFFICE OF LAURA I. FORMUSA
FILE
RECEIVED
MAR 23 2007
B.F.
REFER TO
COPY FOR

March 23, 2007

Ms. Laura Formusa
President and CEO (Acting)
Hydro One Inc.
483 Bay Street
Toronto, ON
M5G 2P5

Dear Laura:

Re: A New Transmission Line from the Bruce Area to the Greater Toronto Area

The purpose of this letter is to urge Hydro One Networks Inc. to initiate the activities necessary to construct a new double-circuit 500 kV line between the Bruce Nuclear Power Complex and Hydro One's existing Milton switching station located in the Town of Milton in the western part of the Greater Toronto Area (GTA) for in-service by December 1, 2011. These activities include, but are not limited to, seeking and acquiring required permits, regulatory and environmental approvals, and conducting engineering work and prudent purchase of materials needed to meet the required in-service date.

Our letter to you, Mr. Paul Murphy of the IESO, and Mr. Duncan Hawthorne of Bruce Power, dated December 22, 2006, provided the background, basis and rationale for the need for a long-term solution to reinforce the transmission system out of the Bruce area. The OPA has determined that this long-term solution is a new 500 kV line from the Bruce area to the GTA.

Recognizing that the time needed to complete a project of this magnitude would not meet the timing required to fully tap into additional generation capacity available in the Bruce area, the December 2006 letter recommended that a set of near-term and interim measures should also proceed as soon as possible. These measures are expected to provide the required increase in transmission capability to permit the available power in the Bruce area to be transmitted to Ontario load centres until a long-term solution is in place.

The long-term solution for reinforcing the Bruce transmission must (a) meet the need to deliver the existing, committed and forecast renewable and other resources in the Bruce area in a safe, reliable and cost-effective manner, and (b) be consistent with Ontario's land use policy. The need and rationale for this line are discussed in more detail in the OPA's Transmission Discussion Paper #5 and Discussion Paper #7, the OPA's preliminary IPSP, which were presented to stakeholders in the OPA's Integrated Power System Plan (IPSP) Stakeholder Workshop held in Toronto last November 22 to 24.

Existing resources in the Bruce area total about 5,000 MW. The committed resources will increase the total to about 6,500 MW between 2009 and 2012, and to 7,300 MW after 2012. The OPA, in the development of the IPSP, also identified the potential for another 1,000 MW of renewable generating resources in the Bruce area. Thus, the long-term solution must be able to increase the transmission capability of the Bruce system from today's 5,000 MW level to about 8,300 MW. From this perspective, the only technically acceptable and practical solution is a new 500 kV double-circuit line from the Bruce area directly to the GTA.

.... 2

Provincial land use policy requires that existing transmission corridors be utilized to the extent possible for new transmission lines. This policy narrows the transmission options to two alternatives – from Bruce to Milton or from Bruce to Essa via Orangeville, as shown in Figure 1.

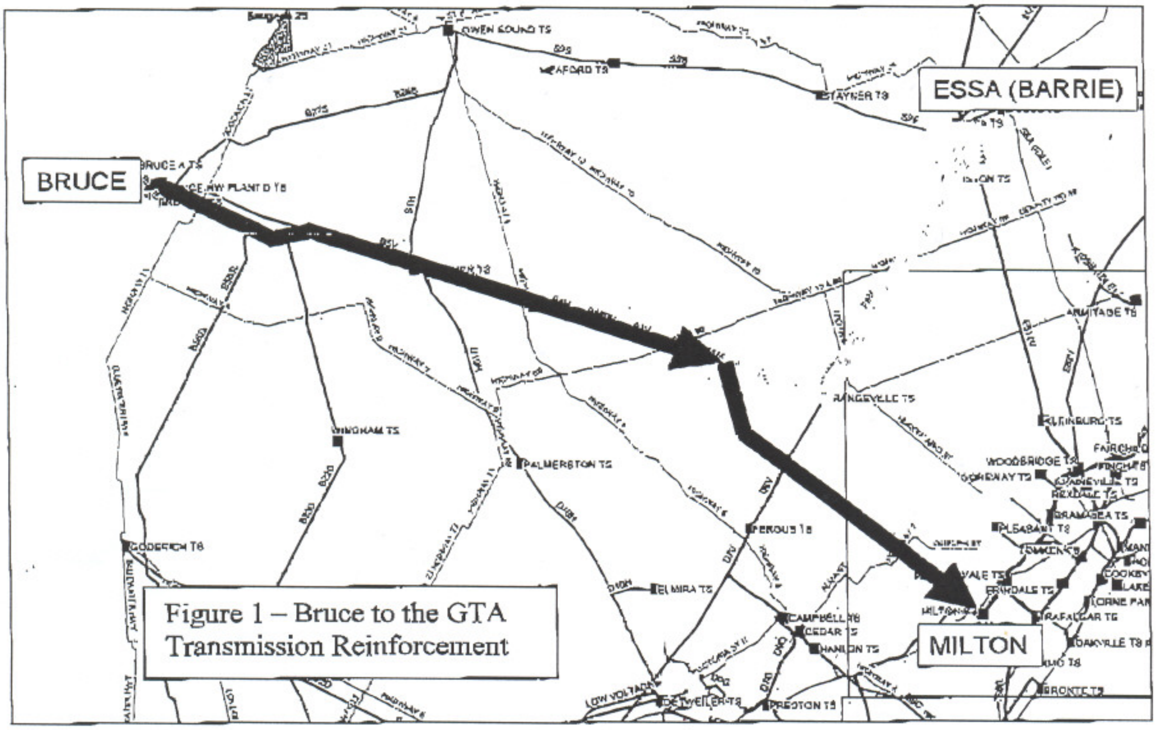


Figure 1 – Bruce to the GTA Transmission Reinforcement

In the past months, OPA, Hydro One, and IESO staff assessed the technical impacts of the two options - Bruce to Milton, and Bruce to Essa. These studies revealed:

- the Bruce to Essa option increases transmission capacity to deliver committed future generation in the Bruce area, including approximately 700 MW of renewable energy capacity. However it does not accommodate the additional 1,000 MW of forecast renewable generating resources, and

- the Bruce to Milton option offers greater capability to deliver future, renewable, generation developments in the Bruce area. Furthermore, unlike the Bruce to Essa option, it does not consume transmission capacity of the Essa (Barrie) to Claireville (GTA) transmission path that is required to accommodate future renewable generation developments north of Barrie.

The feedback from the OPA's IPSP stakeholder workshop has been generally positive concerning the Bruce transmission proposal. Most participants concurred that the transmission capability out of Bruce should be reinforced, particularly to permit the development of renewable generation potential in the Bruce area. Some also commented that, if the new transmission is built, it should have sufficient capability to deliver the existing, committed and future generation in the area. As well, the transmission capability between Barrie and the GTA should be preserved for generation developments north of Barrie.

.... 3

Since early December 2006, OPA and Hydro One staff have consulted with regional/municipal planners in communities that are impacted by the proposed Bruce to Milton line. In total, eleven municipalities, four counties and one region were contacted. During those consultations, OPA and Hydro One staff explained the need for the line and the rationale for routing the new line within a widened existing Bruce to Milton corridor.

Conclusion:

We have concluded that the Bruce to Milton option is the only transmission alternative that meets the overall need to transmit the existing and committed generation in the Bruce area, to facilitate the development of future resources both in the Bruce area and north of Barrie, to be consistent with provincial land use policy; and to reflect the general support to date from stakeholders for a long-term solution within a widened existing transmission corridor.

We believe that it is crucial that implementation work on the Bruce to Milton transmission line project proceed as quickly as possible. This project was included in the OPA's preliminary IPSP. Although this project is consistent with the IPSP, we do not believe that it can await the outcome of the IPSP proceeding if it is to meet the earliest possible in-service date, which Hydro One staff have indicated is December 1, 2011. If you choose to proceed with this project as the project proponent, you will have the support of the OPA in the regulatory process for this project.

Please feel free to contact us should you require any clarification or additional information.

Yours truly,

Jan Carr
Chief Executive Officer

cc Howard Wetston, Chair - OEB
Paul Murphy, CEO - IESO

APPENDIX 5

Transmission Discussion Paper No. 5.


ONTARIO POWER AUTHORITY

November 13, 2006


Ontario's Integrated Power System Plan

Discussion Paper 5: Transmission

Ontario Power Authority™

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November 13, 2006

To Ontario's Electricity Consumers and Stakeholders:

Today, I am pleased to deliver for your consideration "Discussion Paper #5: Transmission", the Ontario Power Authority's (OPA's) fifth of eight envisaged papers on the Integrated Power System Plan (IPSP).

Building on the OPA's "Discussion Paper #1: Scope and Overview", released in June, this series of papers is intended to focus on specific aspects of planning. Together, the papers will provide our current assessment of the building blocks for the IPSP, and the feedback they generate will be important guidance for their further development and the eventual preparation of the plan. Please see the table on the next page outlining the envisaged list of IPSP papers.

The transmission paper's purpose is to elicit discussion on the transmission facilities to be included in the IPSP.

The OPA welcomes your input and participation in a three-day workshop scheduled for November 22nd to 24th. For details on stakeholder input and participation opportunities (and other IPSP matters), please see the OPA's dedicated IPSP Web site (www.powerauthority.on.ca/IPSP/).

In the months ahead, I look forward to receiving your advice, thoughts and comments through the IPSP consultation process and to sharing with you the additional planning documents as they are developed. In addition to the comprehensive report we are releasing today, the OPA will be releasing more data and assumptions in the coming weeks in support of other components of the plan.

I strongly believe that developing a shared understanding of the planning challenges and the concrete steps needed to address them will focus the discussions, improve the dialogue and ultimately result in a better plan for the benefit of all Ontarians.

Yours sincerely,

Amir Shalaby
Vice-President, Power System Planning

OPA's IPSP Discussion Papers

#	Discussion Paper Title	Release
1	Scope and Overview	June 29
2	Load Forecast	Sept. 07
3	Conservation and Demand Management	Sept. 22
4	Supply Resources	Nov. 9
5	**Transmission**	**Nov. 13**
6	Sustainability	Nov. 10
7	Integrating the Elements - A Preliminary Plan	Nov. 14
8	Options for Procurement	TBD

NB: For details on stakeholder input and participation opportunities (and other IPSP matters), please see www.powerauthority.on.ca/IPSP, the OPA's dedicated IPSP Web site.

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1. Summary

This Integrated Power System Plan (IPSP) discussion paper describes Ontario's transmission system, focussing on the areas of need and options for reinforcing and expanding the system. A companion integration discussion paper (#7), which forms the basis of the preliminary IPSP, discusses the specific transmission initiatives that will be included in the preliminary plan.

Significant investment in transmission will be required over the 20-year planning horizon of the IPSP under development.

Transmission is the backbone of the power system. It connects consumers and their utilities to existing generation. It provides access to electricity for new and growing communities. And it enables new generation facilities to be developed.

The Minister of Energy's June 13th, 2006, directive called on the Ontario Power Authority (OPA) to strengthen the transmission system to:

- enable the achievement of the supply mix goals set out in the directive
- facilitate the development and use of renewable energy resources such as wind power, hydroelectric power and biomass in parts of the province where the most significant development opportunities exist
- promote system efficiency and congestion reduction and facilitate the integration of new supply, all in a manner consistent with the need to cost-effectively maintain system reliability.

Since the release of the *Supply Mix Advice Report*, the OPA has undertaken assessments of the transmission development and integration challenges for eight connected transmission "subsystems" or parts of the transmission system in defined areas of the province:

- Northwestern Ontario and its connection to Northeastern Ontario
- Algoma to Sudbury
- North and East of Sudbury
- Sudbury to Barrie
- Barrie to the Greater Toronto Area (GTA)
- Bruce/Southwestern Ontario to the GTA
- Eastern Ontario to the GTA
- Bulk transmission within the GTA

Northwestern Ontario and its Connection to Northeastern Ontario
Modest reinforcement of the transmission system is needed in the northwest to enable up to 400 megawatts (MW) of new generation, mostly from renewable resources and imported electricity from Manitoba, and to accommodate the shutdown of the coal-fired units at Atikokan and Thunder Bay. If there is a need for resource development greater than this level, or for a

significantly larger firm purchase from Manitoba, major transmission reinforcement would be required, both within the northwest and between the northwest and the northeast.

Algoma to Sudbury
The Algoma to Sudbury subsystem is somewhat similar. A modest level of transmission reinforcement is needed to accommodate near-term resource development and the easterly flow of energy originating further west. Major reinforcements and new "enabler" lines will be needed to harvest the significant hydroelectric and wind resources in this area in the medium to long term.

North and East of Sudbury
The transmission system north of Sudbury is adequate for today's requirements. However, it has no capacity to accommodate increased generation. While some smaller generation projects could be integrated in the short term through various capability-enhancing techniques, major investments in the system will be needed to develop hydroelectric resources in the Moose River Basin and the Albany River area (both beyond 2015).

Sudbury to Barrie
The transmission system between Sudbury and Barrie is just adequate for today's power transfer needs. However, further development of renewable resources in the north will increase north-south transfers on this path. In the near term, installing capability-enhancing facilities near Parry Sound will make possible a sizeable increase in power transfers. Major reinforcement would be required to integrate more substantial northern resource development in the longer term.

Barrie to GTA
The transmission system between Barrie and the GTA is adequate today. However, this part of the system will be stressed as new southward flows are added from renewable resource developments in the north and along Georgian Bay, and from generation developments in the Bruce region. The addition of a new 500 kilovolt (kV) line along the existing right-of-way is needed.

Bruce/Southwestern Ontario to GTA
The transmission system in southwestern Ontario is currently challenged in a number of ways:

- There is inadequate transmission out of the Bruce area to accommodate both the expected wind developments in that area and the expanded capacity of the Bruce nuclear station resulting from refurbishment.
- Additional voltage support is needed on this part of the system, particularly in light of the planned phase-out and closure of the Nanticoke facility, which is currently a major source of this support.
- Additional transfer capability may be needed between Sarnia and London to facilitate imports from Michigan and energy from the new natural gas-fired generators in this area. The phase-out of the Lambton coal-fired generation will alleviate this need.
- Additional capacity is needed as a result of growing load in a number of urban centres in this part of the province.

- New enabler lines and related reinforcements are needed to facilitate the development of generation from renewable resources, including wind generation on parts of Lake Huron and Lake Erie.

The paper considers and identifies a range of options for addressing these challenges.

Eastern Ontario to GTA
The transmission system in eastern Ontario is currently adequate for supplying the load areas and delivering any generation surplus and imports from eastern Ontario to the GTA. Preliminary assessments indicate that, with minor reinforcement, the system will be able to accommodate possible renewable resources development in eastern Ontario, about 1,250 MW of power from Quebec and a moderate level of additional generation development.

Bulk Transmission within GTA
There are a number of transmission issues facing the GTA and, in particular, the downtown Toronto core. These issues relate to the shortage of local generation, the aging of the infrastructure, risks associated with having only two major supply corridors, and the difficulty and expense of developing new infrastructure in heavily built-up urban areas. Significant transmission reinforcements may be required for new major generation developments outside the GTA and nuclear retirements within the GTA. In addition, there are significant area supply issues related to rapid population growth and commercial development in the outlying areas of the GTA.

This discussion paper examines the environmental sustainability of 12 potential transmission projects. The analytic framework supporting these preliminary assessments is presented in the OPA's sustainability discussion paper (#6) posted on the Web site. Each assessment looks at the socio-economic and environmental characteristics of the projects.

The paper concludes with a discussion that assesses the potential transmission investments, in aggregate, against five policy objectives: enabling achievement of the supply mix goals, facilitating the development and use of renewable energy resources, promoting system efficiency and congestion reduction, expanding the system while cost-effectively maintaining system reliability and enabling the smart gas strategy.

1.1 Request for Stakeholder Comment

This paper describes the transmission considerations, requirements and plans proposed for the development of the Ontario power system. Its purpose is to guide and support the OPA's consultation with stakeholders. Input from stakeholders and interested parties will assist the OPA in formulating the resources and transmission components of the IPSP. **Please provide your comments in writing and submit them to the OPA only through one of the two following channels:**

- To make a submission electronically, please use the online form at the following Web site link, which includes instructions for sending submissions as attachments: http://www.powerauthority.on.ca/ipsp/Page.asp?PageID=751&SiteNodeID=231&BL_ExpandID=155\
- To send a submission through the regular mail or by courier, please send it to: IPSP Submissions, Ontario Power Authority, 120 Adelaide Street West, Suite 1600, Toronto ON M5H 1T1

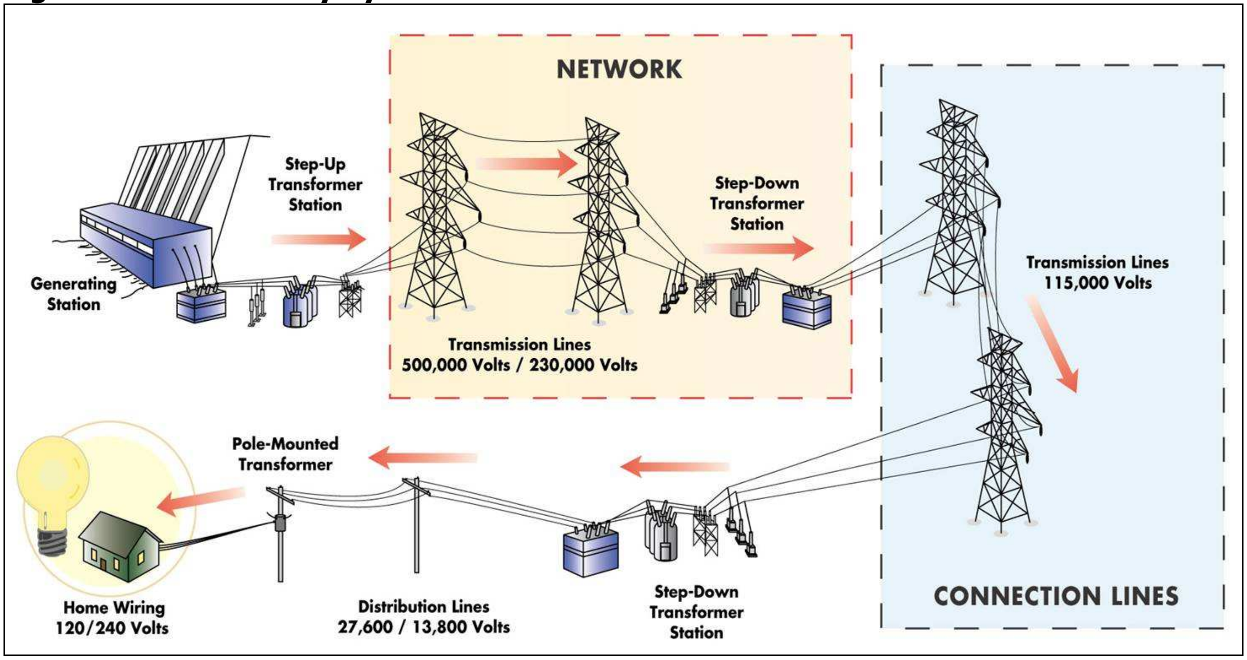
Given the volume of correspondence, submissions sent to specific individuals at the OPA may not be reviewed or considered.

2. Regional Characteristics, Issues and Possible Solutions

2.1 Background: Ontario's Transmission System

Transmission is a key enabler for the delivery of electricity from producers to end users, as illustrated in Figure 2.1. Electricity produced at a generating station is “stepped-up” by nearby transformers to high voltages so it can be moved long distances over transmission lines to minimize power loss. The voltage is then “stepped-down” at transformer stations for supply to regional subsystems which connect large customers or distributors. Power is stepped-down to distribution voltages and carried to distribution points where it is further stepped-down to supply local residential, commercial and smaller industrial customers.

Figure 2.1 – Electricity System Schematic

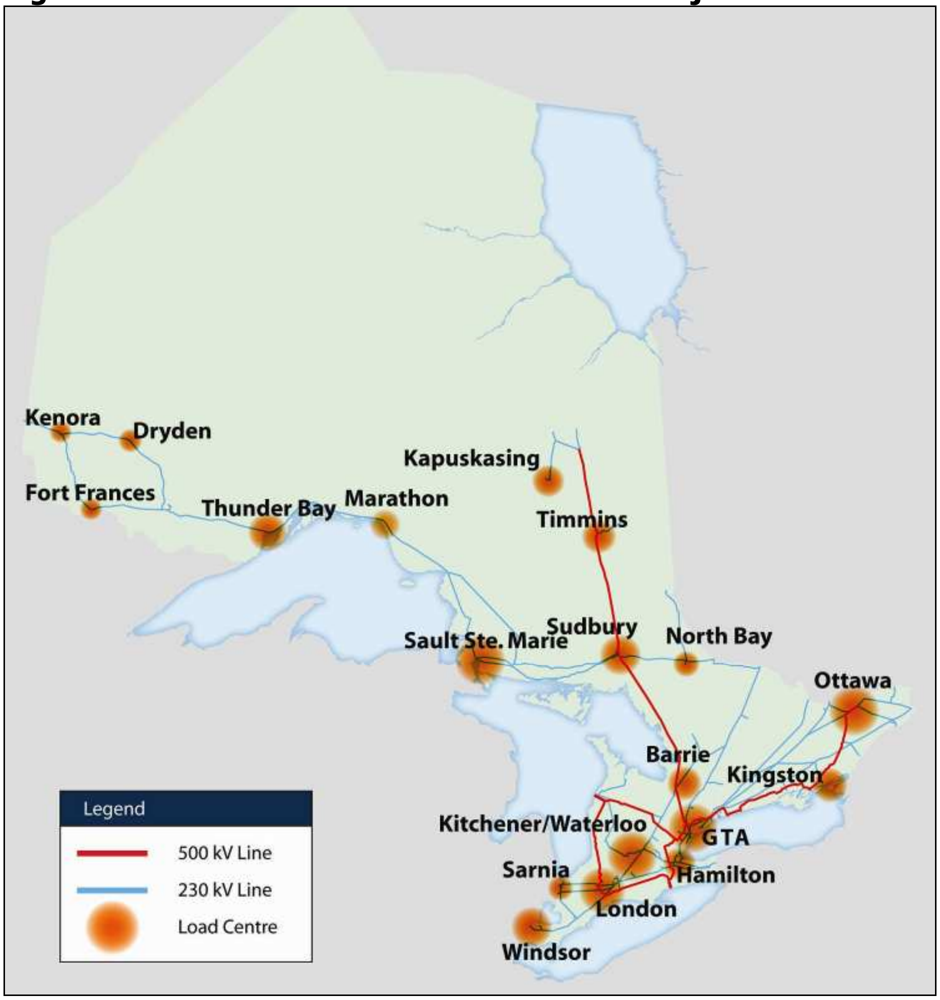


Source: Hydro One Networks Inc.

The electricity delivery system in Ontario consists of a vast network, spanning a large geographic area, of interconnected transmission and distribution lines and related facilities. There are approximately 300 transmission stations and 30,000 km of transmission circuits in Ontario. The Ontario transmission system operates mainly at three voltages levels: 500 kV, 230 kV and 115 kV. In small parts of the system, there are also transmission facilities operated at 345 kV and 69 kV voltage levels.

The Ontario transmission system forms an integrated transmission grid that can be divided into two components based on function. The integrated network, or bulk system, operates primarily at 500 kV or 230 kV over relatively long distances and links major sources of generation to transmission stations and larger area load centres. Figure 2.2 shows the bulk transmission system in Ontario and the major load centres that the bulk system connects.

Figure 2.2 – Ontario Bulk Transmission and Major Load Centres



Source: IESO and OPA

In southern Ontario (south of Sudbury), the bulk transmission system is predominantly the 500 kV and 230 kV network. In northern Ontario, most of the bulk system is at the 230 kV level with one 500 kV line from Sudbury to north of Kapuskasing. The area supply system operates at 230 kV or 115 kV and links the bulk system to local generators and loads. In Figure 2.1, the "network" represents the bulk transmission system and the "connection lines" represent the more local supply areas.

Figure 2.3 – Ontario Interconnections

Source: IESO and OPA

The Ontario system, shown in Figure 2.3, is connected to the transmission systems of Manitoba, Minnesota, Quebec, Michigan and New York. Ontario has in total 27 interconnection circuits with its neighbouring systems. Sixteen of these interconnections are operated parallel, which means there is a simultaneous connection between Ontario and the other system. Eleven of these interconnections are operated non-parallel. In these cases, a generation or load area is electrically disconnected from one system before connecting to the other system. All existing interconnections to Quebec are non-parallel.

In summer periods, the Ontario interconnections provide a combined import capability of 2,800-4,700 MW and a combined export capability of 3,700-5,300 MW. Winter import and export capabilities are typically higher due to higher line capabilities in colder weather. Import and export capabilities vary in actual operations due to a number of factors. These include limitations within Ontario or in another jurisdiction's transmission system, unscheduled power flowing between interconnected systems and variations in load and generation patterns.

The Ontario transmission system is a part of the Eastern Interconnection which includes the eastern two-thirds of the continental United States and Canada. The Eastern Interconnection extends from Saskatchewan, east to the Maritime provinces and south to Florida. On the basis of load size, the Ontario system makes up less than five percent of the Eastern Interconnection load. Being part of a larger system provides security and economic benefits. In addition to the ability to import and export generation, interconnections to a large system provide greater robustness to withstand major disturbances and reduces the levels of generation reserve required to maintain system security in Ontario.

Some Ontario electricity organizations are members of the Northeast Power Coordinating Council (NPCC) whose mission is to promote the reliable and efficient operation of the interconnected bulk power systems in northeast portions of North America. It does this by establishing reliability standards and criteria; coordinating system planning, design and operations; and assessing compliance with such criteria. Ontario entities also participate in the North America Electric Reliability Council (NERC), which was created in 1968 to ensure the bulk electric system in North America is reliable, adequate and secure. NERC was recently certified to become the Electric Reliability Organization (ERO) that spans North America, with the Federal Energy Regulatory Commission (FERC) exercising oversight in the United States. NERC is also seeking recognition as the ERO from governmental authorities in Canada and has submitted applications with the National Energy Board and eight provinces in Canada. The OEB oversees NERC in Ontario. The Independent Electricity System Operator (IESO) is the NERC reliability coordinator for Ontario. IESO also establishes the Market Rules and the Transmission Assessment Criteria.

The planning, design and operation of the transmission system in Ontario is governed by the rules, criteria, standards and guidelines established by the IESO, NPCC and NERC to ensure a reliable system that provides both security and adequacy of supply to the people of Ontario.

2.2 Scope of this Paper

This paper covers the Ontario bulk transmission network[1] and the transmission subsystems that serve the major regional centres across the province. It will also touch on a number of transmission-related local area supply needs. The details of the OPA's planning for these local area needs is being addressed in a separate stakeholder engagement process focused on the affected communities.

[1] The bulk power system is a term used to mean the interconnected electrical systems of North America, specifically, the generation, transmission and system control facilities to which faults or disturbances can have a significant adverse impact outside of the local area. For present purposes, this means the collection of Ontario facilities having the potential to impact reliability outside Ontario, if for example, a single resource were to unexpectedly be taken out of service.

Transmission is a key integrating element of the IPSP. It provides services, including:

- delivering power reliably to consumers
- enabling the development of renewable energy and other resources
- facilitating the reduction or removal of operating constraints and system inefficiencies
- improving operational flexibility and catering to changing customer needs
- ensuring there is a robust system to mitigate high-impact, low-probability events.

Since the preparation of the *Supply Mix Advice Report*, the OPA, with the assistance of the IESO, Hydro One Inc., Brookfield Power and other sector entities, has assessed the transmission development and integration challenges. The assessments have identified eight bulk transmission subsystems in Ontario. In terms of their impact on future resource development, five transmission subsystems are related to renewable resources and three to conventional resources, as follows:

Northern Renewable Resources – The following subsystems relate primarily to the development of renewable resources in northern Ontario, including any major purchases from Manitoba, and the efficient and uncongested delivery of these resources to supply loads in southern Ontario:

- northwestern Ontario and connection to northeastern Ontario
- Algoma to Sudbury
- north and east of Sudbury
- south from Sudbury to Barrie
- south from Barrie to the GTA.

Conventional and Southern Renewable Resources – The following subsystems relate to the development of conventional and renewable resources in southern Ontario:

- Bruce/southwestern Ontario to the GTA
- eastern Ontario to the GTA
- bulk transmission system in the GTA.

The Bruce/southwestern Ontario to the GTA subsystem is important for incorporating additional nuclear generation at the Bruce site, renewable resources in southwestern Ontario, the phase-out of coal-fired generation at Nanticoke and Lambton and maintaining import capability from the U.S.

The eastern Ontario to the GTA subsystem is related to the development of new generation and renewable resources in eastern Ontario, including any major purchases from Quebec or Labrador.

One issue in facilitating the development of renewable resources is the availability of transmission to connect these resources to the transmission grid. Many of these developments are singular and located far from existing transmission lines. It would not be economic to develop these resources if a dedicated long transmission line is required for their connection. Others, however, are sufficiently clustered to form major centres of resource development, so that a dedicated transmission line could be justified. These lines, referred to as enabler lines in this discussion paper, would be generation connection lines developed to enable the development of renewable resources consistent with the policy objectives in the government's directive. Thus, they may be considered as part of the network assets. The commitment to construct these enabler lines would coincide with the commitment of their associated generation resources, to avoid the lines becoming stranded assets.

Beyond resource development needs, there are transmission-related reliability and supply adequacy issues affecting a number of large load centres. They include the GTA, Kitchener-Waterloo-Cambridge-Guelph, Windsor/Essex, southern Georgian Bay, Woodstock, Brant, Thunder Bay and northern York Region. These needs will be highlighted in the discussion of the appropriate transmission subsystems.

This discussion paper provides rough estimates of solution costs and project lead times. All costs presented are preliminary or order-of-magnitude estimates based on typical unit costs. More detailed estimates are being prepared by the appropriate entities. The lead times provided are for typical transmission projects with uncomplicated approval and permitting expectations. For major and contentious projects, the lead times may be one to two years longer than indicated.

Appendix 1 provides a brief description of the power system concepts, terms and special facilities covered in the IPSP Transmission Discussion paper.

2.3 Transmission Subsystems Needs and Solutions

The following sections will provide a brief description of the eight transmission subsystems, and the issues and challenges related to load supply and resource development in these subsystems. Potential solutions are also identified. It is important to note that the solutions presented for addressing the identified needs in this paper are a survey of potential options, not a recommendation on whether any of those options should be implemented or the sequencing of the options, unless stated otherwise or as appropriate. In many cases, transmission development is related to decisions made on resource development.

The environment and sustainability considerations for the transmission elements of the integrated plan are covered in Section 3 of this discussion paper.

To address local area reliability needs, both transmission and non-transmission solutions are being considered. These projects are undergoing their own stakeholder and community engagement processes. In many cases, the preferred solution(s) to address the identified needs have not been determined. They will be included in the draft plan at a later stage.

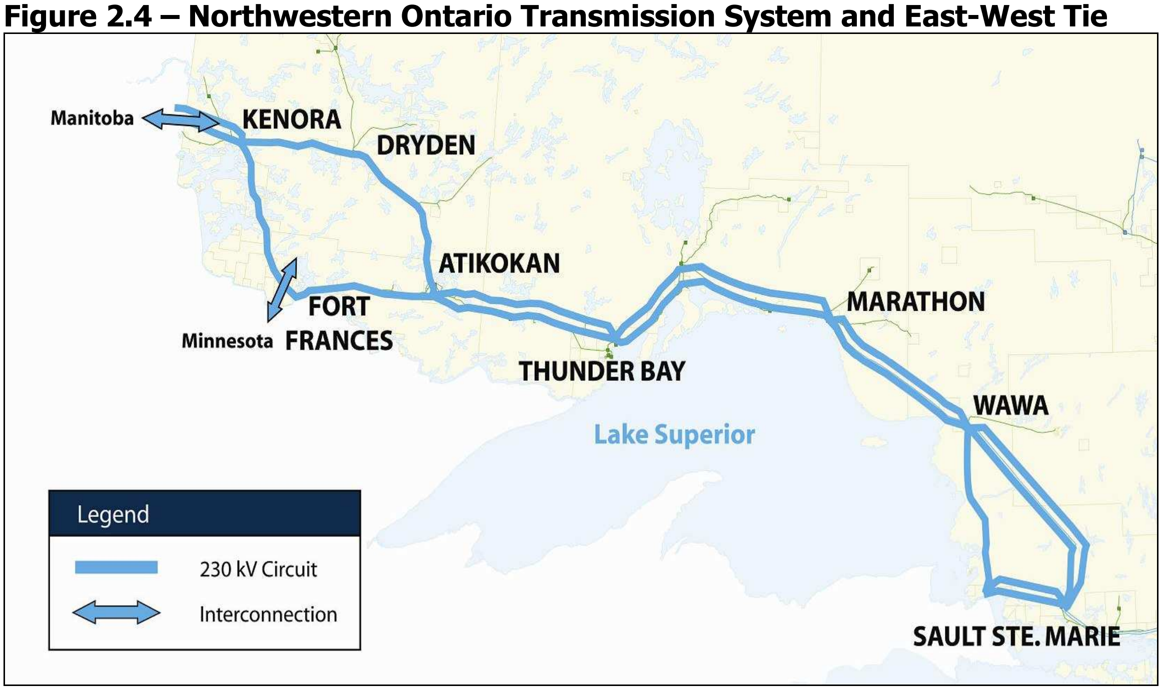
2.3.1 Northwestern Ontario and Connection to Northeastern Ontario

The 230 kV transmission system in northwestern Ontario (northwest) and the interconnection between northwestern Ontario and northeastern Ontario (northeast) are shown in Figure 2.4.

The northwest transmission subsystem consists of two 230 kV circuits extending from the Manitoba border to the Thunder Bay area, a distance of about 500 km. From there, the northwest system is connected via two 230 kV circuits on a common tower line to the northeast system in the Sault/Algoma area, a distance of about 600 km. This transmission connection between the northwest and northeast is commonly referred to as the East-West Tie. The northwest is also interconnected with the power systems in Manitoba and Minnesota. These critical delivery paths are highlighted in Figure 2.4.

Long distances and few circuits are the dominant features of the northwest transmission system and the East-West Tie. These features, coupled with the 230 kV operating voltage, result in a fairly limited power transfer capability on the northwest transmission system and on the East-West Tie. In particular, the East-West Tie, which has a transfer capability of about 325 MW, has frequently limited the amount of power that can be delivered between the northwest and other regions of Ontario. As well, transmission losses are high for power transfers across the northwest system and through the East-West Tie. For example, at an East-West Tie loading of 200 MW, flowing towards the northeast, the incremental losses for a further 100 MW of transfer from Kenora to the GTA would be about 35 percent. That is, of the additional 100 MW injected into the system at Kenora, only 65 MW would be received in the GTA.

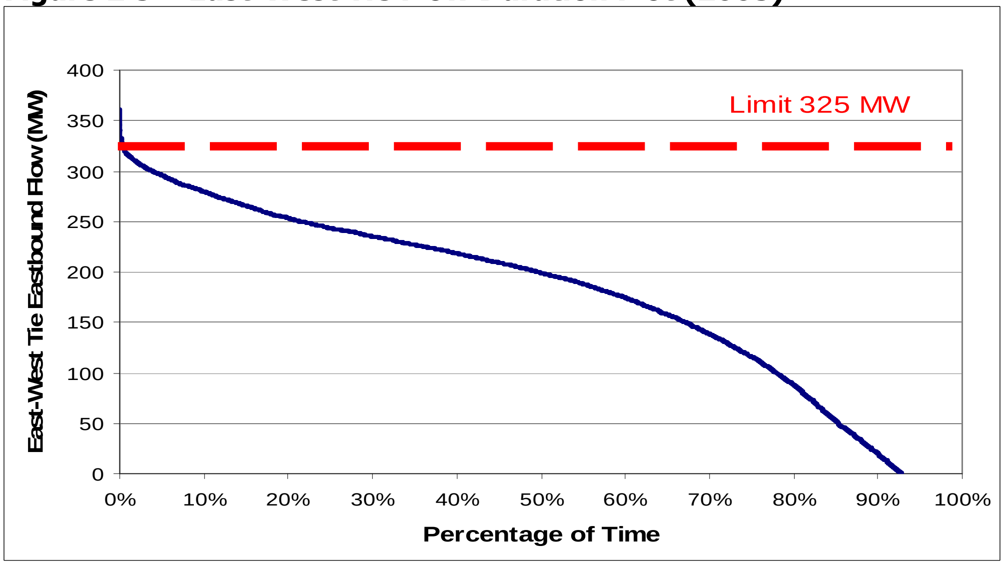
Figure 2.4 – Northwestern Ontario Transmission System and East-West Tie



Source: Hydro One Networks Inc. and OPA

Figure 2.5 shows the actual power transfers on the East-West Tie in 2005, as recorded by the IESO. This type of graph is commonly referred to as a flow duration plot and can give information on how the path is used – transferring how many MW and how often. A simple way of developing this graph is to plot the hourly flow quantities, in this case the transfers on the East-West Tie, in descending order of magnitude over the time period of interest. The transfers shown in the figure are those that resulted after any generation re-dispatches necessary to respect the transmission limits, and not what the transfers might have been without transmission restrictions. As seen in that figure, the flow east reached the capability of the tie during 2005.

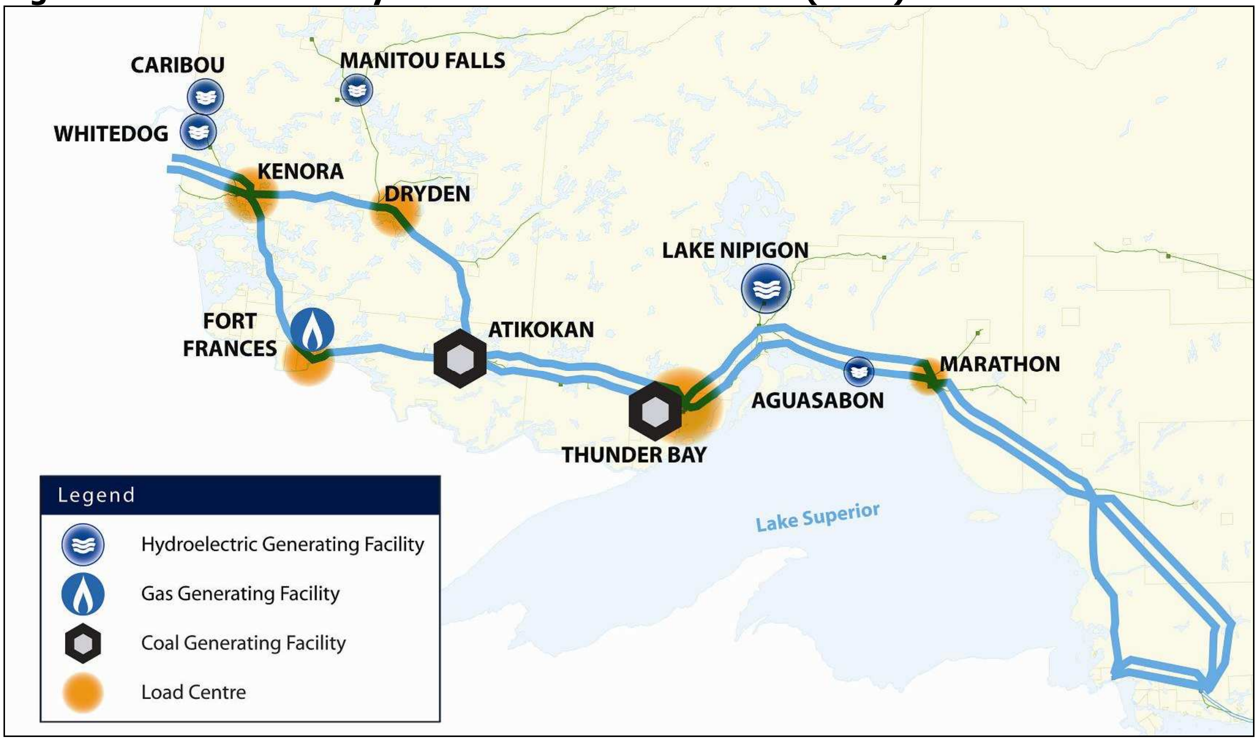
Figure 2.5 – East-West Tie Flow Duration Plot (2005)



Source: IESO and OPA

The major load and generating centres in the northwest are shown in Figure 2.6.

Figure 2.6 – Northwest System - Generation and Load (2005)



Source: Hydro One Networks Inc. and OPA

The existing area loads total about 990 MW. The major load centre is the City of Thunder Bay (450 MW), with smaller centres at Dryden, Fort Frances and Kenora, as shown in Table 2.1. Load growth in the northwest is forecast to be static over the 20-year study period. Although there have recently been some large load reductions in this region due to poor economic conditions for the pulp and paper industry, a major industrial sector in this area, the forecast assumes a gradual recovery of this load.

The existing generation resources in the northwest total about 1,400 MW. Details are shown in Table 2.1. Generally, there has been a balance between demand and supply in the northwest. Generation development has matched the level of demand growth here. Because of the constraints imposed by the transmission system, the northwest is generally self-sufficient in terms of power supply, with some limited ability to interchange power with the rest of Ontario.

Table 2.1 – Northwest Generation and Load (2005)

Northwest Generation	
Zone	**Generation (MW)**
Atikokan	211
Thunder Bay	306
Fort Frances	105
Nipigon area	335
Caribou	87
Whitedog	68
Manitou Falls	74
Aguasabon	47
Other	149
Total	1,382
Northwest Loads	
Zone	**Load (MW)**
Kenora / Dryden / Atikokan / Fort Frances	280
Thunder Bay / Nipigon area	445
Marathon	110
Other	155
Total	990
Interconnections	
Manitoba	**Capability (MW)**
Import – Summer	331
Export – Summer	263
Import – Winter	343
Export – Winter	275
Minnesota	
Import – Summer	90
Export – Summer	140
Import – Winter	90
Export – Winter	140

Source: IESO and OPA

In planning for the northwest in the IPSP, there are a number of potential resource developments in the region that will have major implications on the transmission system in the area. They are:

- shutdown of Atikokan and Thunder Bay generating stations
- development of renewable resources
- large purchase from Manitoba.

Shutdown of Atikokan and Thunder Bay Generating Stations - One of the policy objectives of the Ontario government is to replace coal-fired generation in the province. Consistent with this is the assumption that the existing coal-fired generation at Atikokan GS (211 MW) and Thunder Bay GS (2x153 MW) will be phased-out, once the overall system adequacy and local supply reliability issues have been addressed.

The shut-down of the Thunder Bay generating units will have a major impact on the reliability of supply to the City of Thunder Bay. The loss of this 306 MW of local supply will necessitate the transfer of an equivalent amount of power from the bulk transmission system at the Lakehead station through the 115 kV network serving Thunder Bay. This network does not have adequate capacity for this purpose. The recent reduction of about 130 MW of load in Thunder Bay has alleviated this problem somewhat, but even at this reduced load level, additional reactive power support is required at the Lakehead and Thunder Bay stations to maintain adequate voltages in the area.

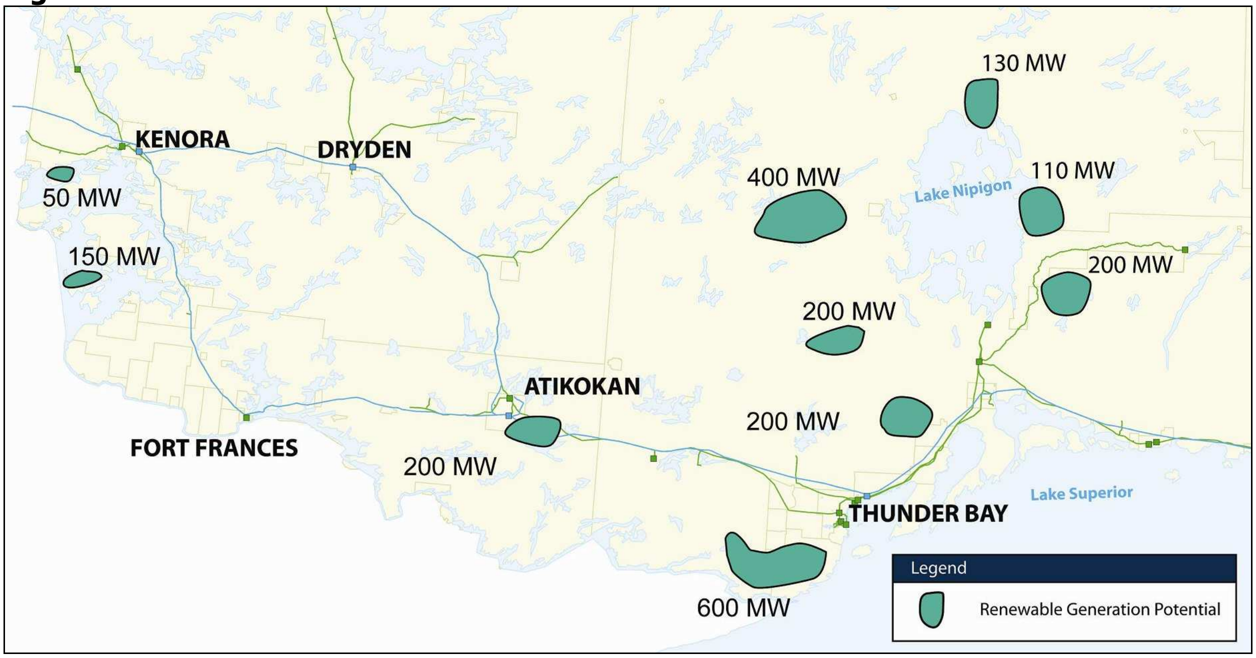
To accommodate the recovery of load in the Thunder Bay area over the longer term, we are assessing local generation and transmission reinforcement solutions to augment the area load supply capacity. The most likely of the transmission options is the construction of a new double-circuit 230 kV transmission line from the Lakehead station to the Birch station, a distance of about 22 km. The estimated cost of this line is about $60 million.

As the large pulp and paper industry load constitutes a significant portion of Thunder Bay's overall demand, and given that this load can recover fairly quickly when economic conditions for the industry improve, we believe that the process to obtain environmental assessment and regulatory approvals for this line should be initiated early, and approval should be in hand prior to the shutdown of the Thunder Bay generating station. The construction of this line, however, would not be triggered until the load recovers in this area, or if non-transmission options are insufficient to maintain an adequate reliability of supply.

The shutdown of the Atikokan plant will impact the ability to maintain and control voltages on the transmission system between Kenora and Thunder Bay. This could result in the need to further constrain transfers within the northwest system and on the interconnections with Manitoba and Minnesota. At a minimum, to maintain the present transfer capability following the shutdown of the Atikokan generating unit, additional shunt capacitors are required at Fort Frances and Dryden at an estimated cost of $5 million. Dynamic reactive power support (e.g., static var compensators) may be required if transfers were to increase beyond today's level as a result of reduced load west of Atikokan and/or increased transfers from the Manitoba or Minnesota interconnection.

Development of Renewable Resources - A recent study of the renewable energy potential in Ontario identifies about 2,250 MW of potential generation from renewable resources - wind, hydroelectric, bioenergy and cogeneration - that could be developed in the northwest. Of this total, about 400 MW are identified to be located west of Thunder Bay, about 600 MW near the City of Thunder Bay, about 800 MW north of Thunder Bay and about 450 MW northeast of Thunder Bay (along the east shore of Lake Nipigon). The rest of the identified potential is distributed throughout the region. This is shown in Figure 2.7.

Figure 2.7 – Northwest Renewable Generation Potential

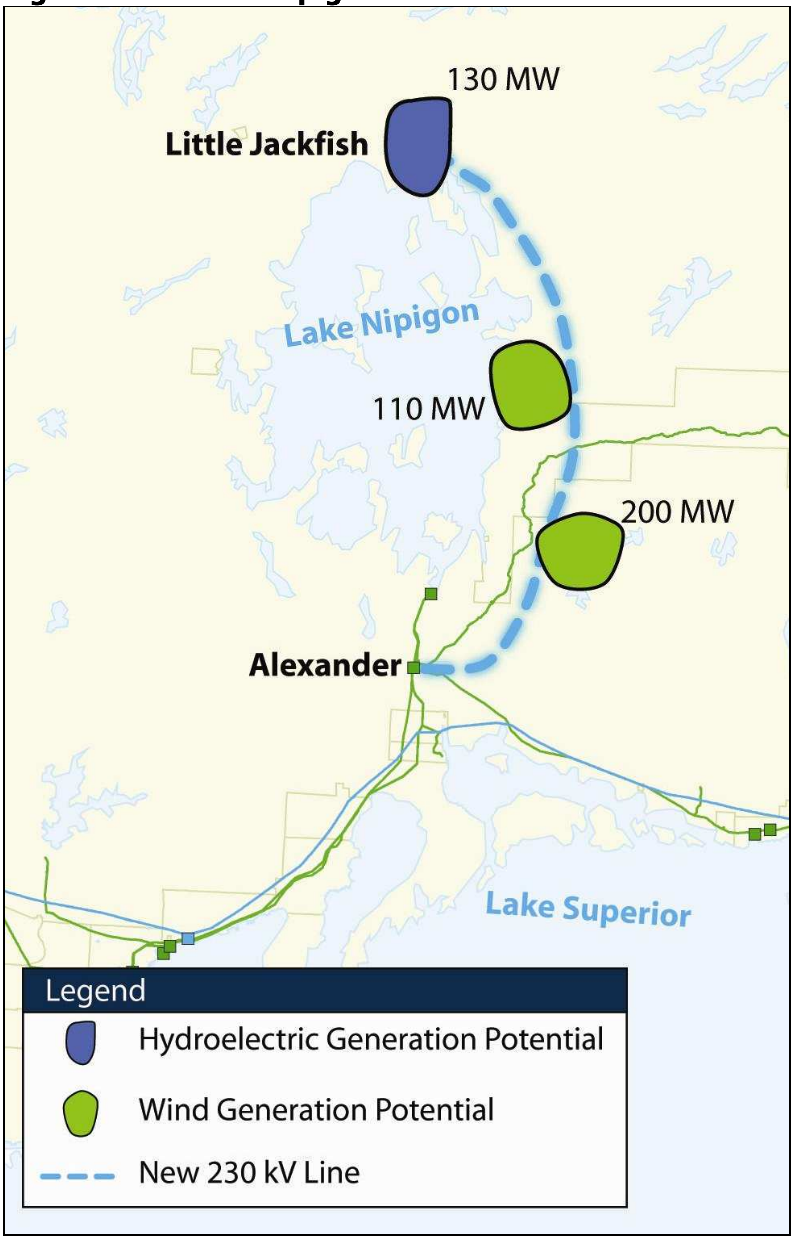


Source: Hydro One Networks Inc. and OPA

In the northwest, there is a need for two enabler lines. As with all enabler lines, they would proceed only if their associated resource development proceeds.

The first enabler line is related to the potential development of the hydroelectric generation at the Little Jackfish site and the wind generation along the east shore of Lake Nipigon, as shown in Figure 2.8. A 185 km single-circuit 230 kV line from the Alexander station to the Little Jackfish site and a 230 kV connection to the East-West Tie near the Alexander station would permit the connection of about 400 MW of combined hydroelectric and wind generation in this area to the main transmission grid. The cost of this line is about $150 million. The assumption of a single circuit here is premised on the ability of the northwest system to withstand the loss of the 400 MW for a single element contingency. More detailed studies will be necessary to confirm this. In the event that the northwest is not capable of withstanding this contingency, then the 400 MW of resources would have to be limited to about 200 MW (similar to the size of the Atikokan unit -- the largest single loss of supply in the northwest today) or provide two connecting circuits to incorporate the resources.

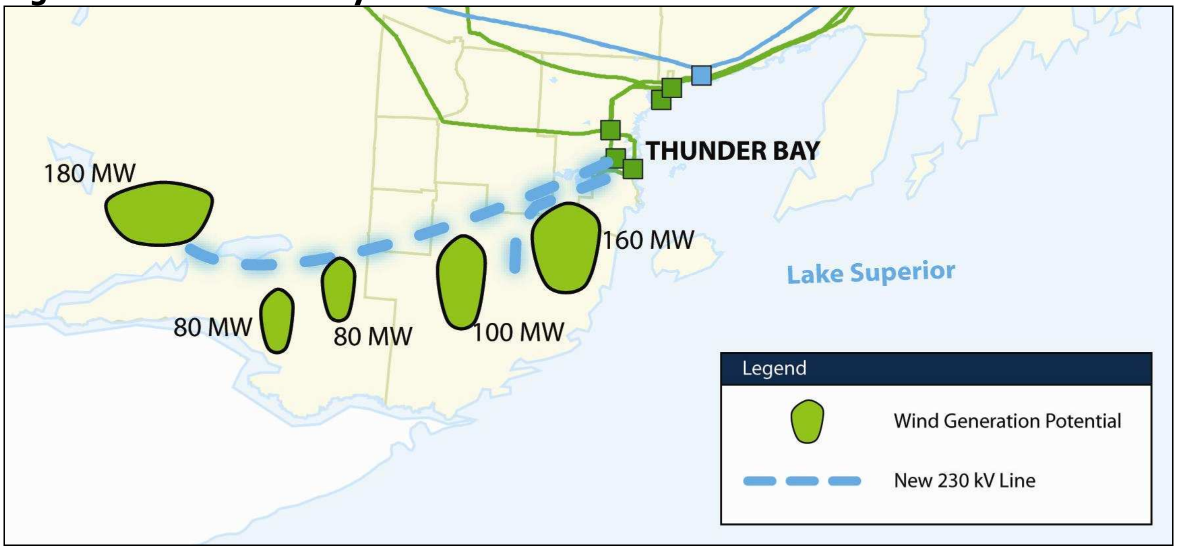
Figure 2.8 – Lake Nipigon Enabler Line



Source: Hydro One Networks Inc. and OPA

The second enabler line is identified for connecting a large pocket of renewable resources located south of Thunder Bay, as shown in Figure 2.9. A single-circuit 230 kV line, 120 km in length, with some double-circuit sections, would allow about 600 MW of wind generation to be incorporated from the area south of Thunder Bay. The cost of this line is about $100 million. The same comment concerning the limitation of the permissible single loss of supply in the northwest applies here. A second line would be required if the loss of over 200 MW is not acceptable. It is also assumed that the Lakehead station to the Birch station 230 kV line, discussed earlier for securing the load supply in the City of Thunder Bay, is in place to connect this enabler line to the northwest transmission network.

Figure 2.9 - Thunder Bay Enabler Line



Source: Hydro One Networks Inc. and OPA

The estimated lead time required for these two enabler lines is four to five years, including the time required for regulatory and environmental assessment (EA) approvals.

Another issue with facilitating renewable resource development in the northwest is the capability that is required to transfer this power across the grid once the resource is connected to the transmission system. While the provision of the enabler transmission lines will facilitate the connection, the transmission capability of the northwest system and the East-West Tie is quite limited for transferring the power generated from these resources to the large load in southern Ontario, as discussed earlier. The planned shut-down of the 211 MW unit at Atikokan and 306 MW at Thunder Bay provides some potential for new generation development in the northwest or a greater level of purchases from Manitoba; roughly 200-400 MW of replacement generation or purchases would be acceptable (of that, only 200 MW could be accommodated west of Thunder Bay). Some reinforcements of the northwest system may be required, depending on the location and size of the resource development.

For resource development beyond the 200-400 MW range, major reinforcements of the northwest transmission system and the East-West Tie will be required. Due to the long and sparse nature of the transmission system in the northwest, there is little opportunity to extract additional capacity by upgrading the existing transmission facilities. Also, at the present time, the northwest system does not satisfy the NERC planning standards. Thus, any major increase in transmission capacity and/or improvements to the reliability level to meet the NERC planning standards in the northwest will require the building of new high-voltage lines in northwestern Ontario and between northwestern and northeastern Ontario.

The most likely scenario to gather the renewable resources within the northwestern system is through the expansion of the northwest 230 kV network. As an example, a new single-circuit 230 kV line could be built from Kenora to Thunder Bay. This would provide an increase of about 300 MW in the transfer capacity from Kenora to Thunder Bay and would cost about $450 million.

The East-West Tie would likely be reinforced using high-voltage direct current (HVDC) technology. Such a line may connect Thunder Bay to Sudbury, providing a capacity of about 1,500 to 2,000 MW. Including the required converter facilities, preliminary cost estimates for this reinforcement would be between $1.6 billion to $2.0 billion. A portfolio of large renewable resource development would be required to justify this level of transmission investment. The lead time required for a project of this major magnitude would be five to seven years.

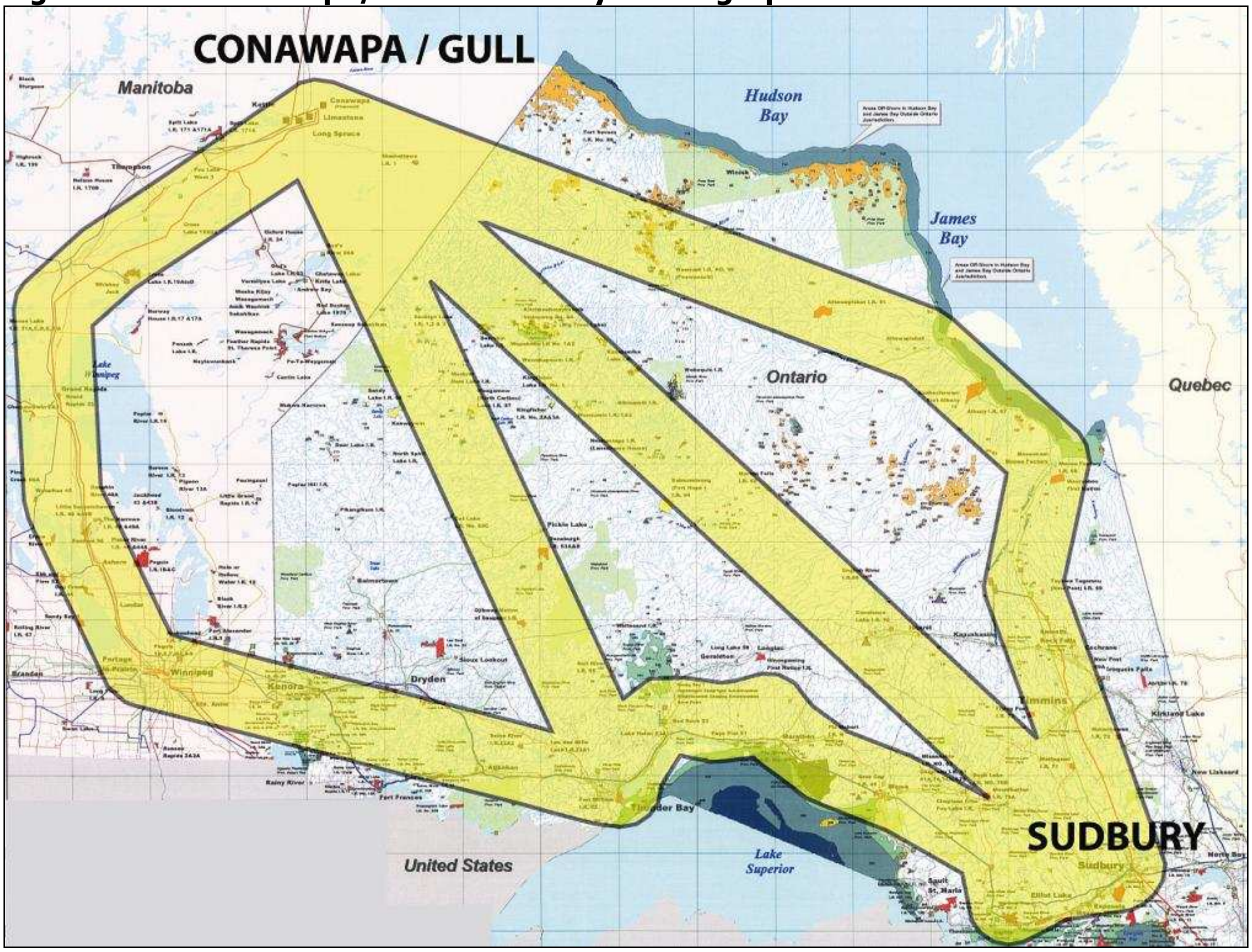
Large Purchase from Manitoba – There is a potential for a large purchase of up to 1,250 MW from Manitoba, in expectation of the province developing its Conawapa and Gull hydroelectric sites. For transmitting this power to the Ontario grid, an HVDC line of about 1,500 MW of capacity is required, initially from a Manitoba hydroelectric development site to the Sudbury area, and from there, to the GTA. A second HVDC line would be required for the entire 3,000 MW development.

There are a number of routing options and configurations that are possible for the HVDC lines. Some of the possible routings are shown in Figure 2.10. This information was obtained from a report *Northwest Ontario Transmission Line Study*, July 2006, commissioned by the Ontario Ministry of Energy. Some of the routes traverse through areas of potential wind and hydroelectric developments in northwest Ontario and First Nation settlements. The potential for multiple uses of the line and right-of-way was one of the considerations of the study.

The cost estimate for a HVDC line along the shortest path from Conawapa/Gull to Sudbury is about $2.3 billion. A higher capacity line, e.g., up to 2,000 MW, would facilitate additional resources from the northwest to be transmitted to northeast. However, this would increase the overall line and converter costs and require a third converter terminal to be provided in the northwest, likely in the Thunder Bay area. A typical cost for a 500 MW converter station is about $75 to $100 million.

Additional transmission reinforcements will be required from Sudbury to the GTA to accommodate these levels of purchases from Manitoba. The specific requirements must be considered in the context of other resource developments that may occur in northern Ontario.

Figure 2.10 – Conawapa/Gull To Sudbury Routing Options



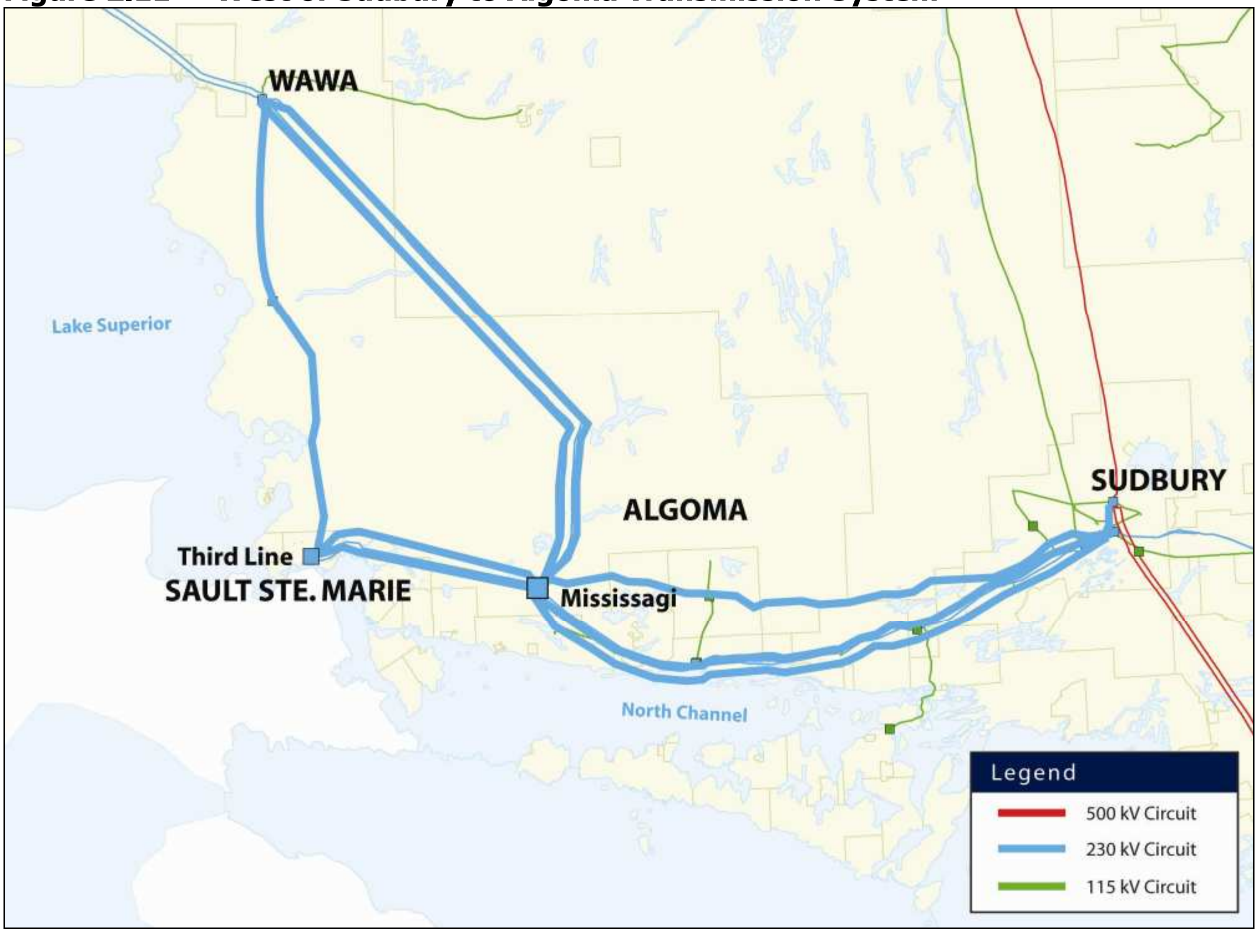
Source: SNC Lavalin and OPA

In summary, with some modest reinforcement of the northwest transmission system, the shutdown of the coal-fired units at Atikokan and Thunder Bay can be accommodated and 200-400 MW of new resources - wind, bioenergy, hydroelectric, combined heat and power generation or increased purchases from Manitoba - can be developed in the area. "Enabler" transmission lines would be required to facilitate connecting a number of potential renewable resource developments. Enabler lines to the Little Jackfish hydroelectric development along the east shore of Lake Nipigon and to the wind-rich area south of Thunder Bay have been identified. For resource development greater than 200-400 MW, major transmission reinforcement is required both in the northwest and between the northwest and the northeast. The cost of a major reinforcement of the transmission system between Thunder Bay and Sudbury for a capacity increase of 1,500 to 2,000 MW is about $1.6 billion to $2 billion. Such investment would probably be triggered by major resource development in the northwest and/or a major purchase from Manitoba.

2.3.2 West of Sudbury to Algoma

The transmission system west of Sudbury extending to the Algoma district is shown in Figure 2.11.

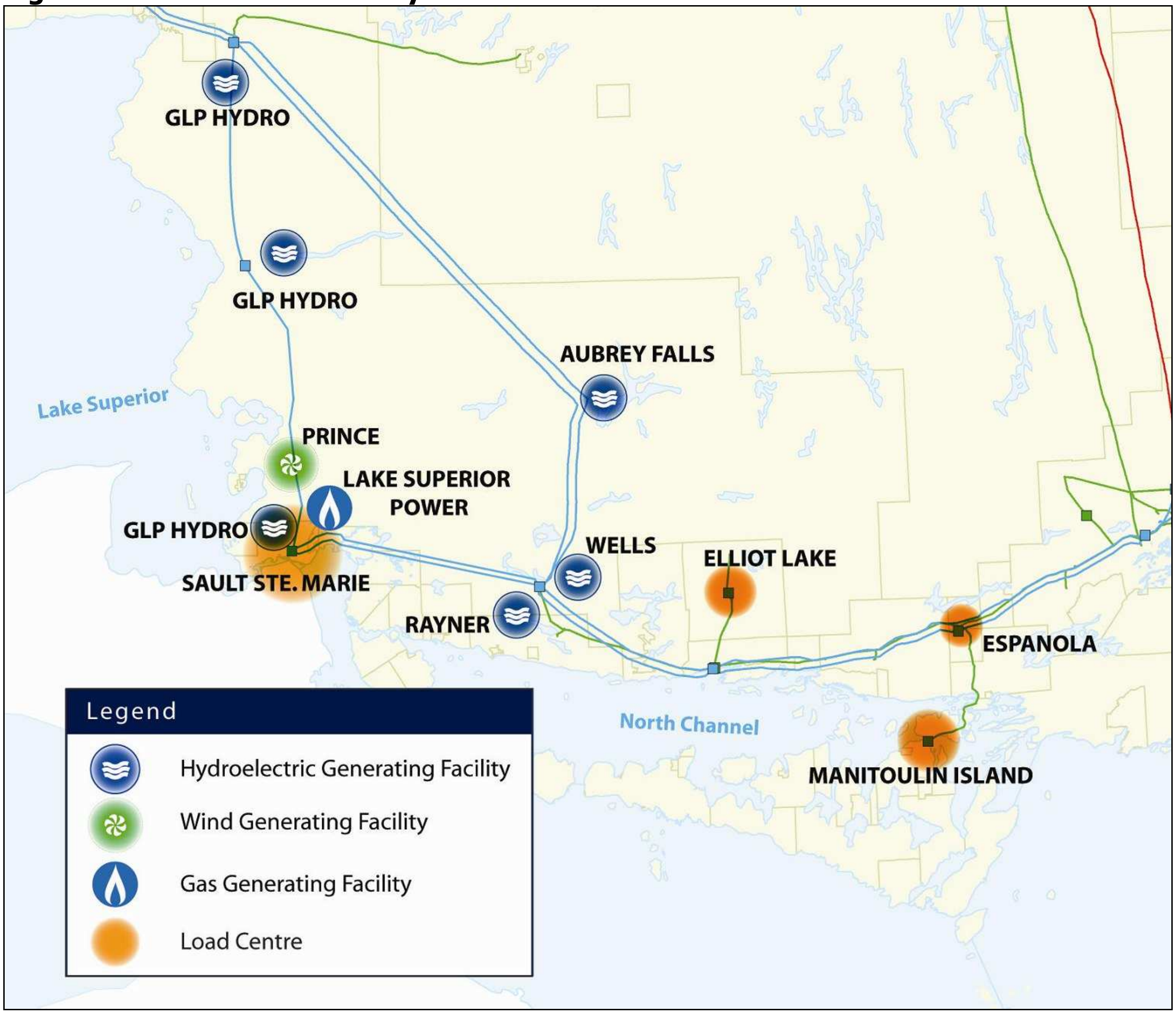
Figure 2.11 – West of Sudbury to Algoma Transmission System



Source: Hydro One Networks Inc. and OPA

The main bulk transmission facilities in this subsystem are three 230 kV circuits connecting the Mississagi station in the Algoma district with stations in the Sudbury area, a distance of about 200 km. The Mississagi station is also the eastern terminus for the two 230 kV circuits that make up the East-West Tie and the connection point for the Great Lakes Power (GLP) system. The connection to the GLP system is via two 230 kV circuits to its Third Line station in Sault Ste. Marie. Within the GLP system, there is a 230 kV circuit between Wawa and Sault Ste. Marie that parallels the East-West Tie circuits between Wawa and Mississagi. These critical delivery paths are highlighted in Figure 2.11.

Figure 2.12 – West of Sudbury Generation and Load



Source: Hydro One Networks Inc. and OPA

The peak load in this subsystem totals about 500 MW. The largest load centre in this subsystem is Sault Ste. Marie in the GLP system, which has a peak load of about 410 MW. There are smaller load centres at Elliot Lake, Espanola and Manitoulin, as shown in Table 2.2. The existing generation capacity in this subsystem is all located west of Algoma and totals approximately 1,050 MW, as shown in Figure 2.12. Much of this generation is renewable - hydroelectric and wind.

Table 2.2 – West of Sudbury to Algoma Generation and Loads (2005)

West of Sudbury to Algoma Generation	
Sites	**Generation (MW)**
Great Lakes Power Hydro	339
Aubrey Falls	164
Rayner	48
Wells	242
Lake Superior Power	120
Prince - Phase I	100
Other	54
Total	1,067

West of Sudbury to Algoma Loads	
Sites	**Load (MW)**
Sault Ste. Marie	412
Elliot Lake	23
Espanola	13
Manitoulin	32
Other	14
Total	494

Source: IESO, Great Lakes Power and OPA

In planning for the area west of Sudbury in the IPSP, there are a number of potential resource developments in the region that will have major implications on the transmission system there. They are:

- incorporation of near-term resources
- development of renewable resources.

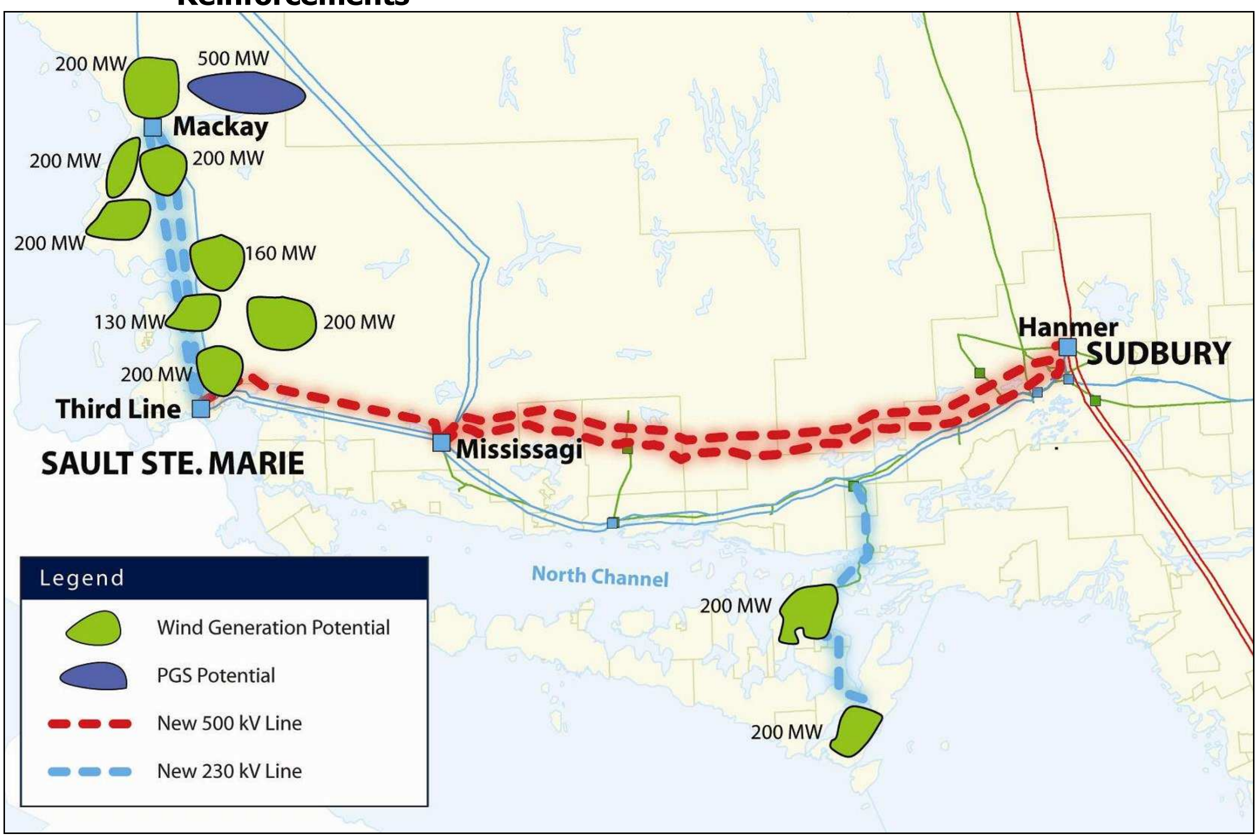
Incorporation of Near-term Resources - In addition to the 1,067 MW of existing generation in this subsystem, another 99 MW will be added in 2008 with the Prince II wind generation development, which is located west of Sault Ste. Marie. There is also 63 MW of generation that was selected as part of the OPA's combined heat and power request for proposal (RFP), which is expected to be added in 2009. Taking the total expected generation in this subsystem net of the load, in combination with the potential inflow to Mississagi via the East-West Tie, this subsystem could have transfers of up to 1,000 MW from the Mississagi station to the Algoma area along the Mississagi to Sudbury delivery path.

This delivery path has an eastbound transfer capability of about 650 MW, which is inadequate based on the expected maximum transfer capacity noted above. This capability can be increased to 800 MW by using generation rejection following transmission outages. A further increase of about 230 MW, for a total capability of 1,030 MW, is possible with the addition of dynamic reactive power devices in the Mississagi station and static shunt capacitors in Algoma to support transmission voltages in the area. With the transmission enhancements at Mississagi and Algoma, the 1,000 MW expected flow in the Algoma area can be accommodated. The cost of this reinforcement is about $50 million and requires a lead time of three years from project approval.

The above enhancements will provide sufficient transfer capability between the Algoma area and Sudbury for the committed resources and will accommodate about 200 MW of new renewable resources in the Manitoulin Island/Espanola area.

Development of Renewable Resources - A recent study of the potential for generation from renewable resources in Ontario identifies about 2,000 MW of attractive wind resources west of Sudbury, in the Sault/Algoma and Manitoulin Island areas. These renewable resources are shown in Figure 2.13. As well, a large pumped generation storage (PGS) facility, 500 to 1,000 MW in capacity, is possible north of Sault Ste. Marie. These are significant resource additions and will require major reinforcement of the transmission system west of Sudbury to the Sault Ste. Marie area.

Figure 2.13 – West of Sudbury - Renewable Resource Potential and Transmission Reinforcements



Source: Hydro One Networks Inc. and OPA

A potential solution for reinforcing this transmission system has three components.

The first is the construction of a new 500 kV line between the Mississagi station and the Hanmer station north of Sudbury. Currently, one of the 230 kV lines from Mississagi to Hanmer is constructed for operation at 500 kV. The towers are already in place although some work is required to replace the insulators and conductors of this line for operation at the higher voltage. Also, there is sufficient width on the right-of-way of this line to add a second 500 kV line between Mississagi and Hanmer. This solution would allow about 1,900 MW of renewable resources to be developed west of Sudbury - roughly 1,500 MW north of Sault Ste. Marie and 400 MW on Manitoulin Island. A preliminary cost estimate for this transmission development is about $535 million.

The second component of the solution is additional transmission within the GLP system to connect any renewable resource or pump storage generation to the transmission grid at Wawa or Mississagi. Preliminary transmission facilities proposed by GLP comprise a double-circuit 230 kV line from their MacKay station near the Montreal River to their Third Line station in Sault Ste. Marie and a single-circuit 500 kV line from the Third Line station to the Mississagi station. The estimated cost of these facilities is about $183 million. More detailed assessment and discussions with GLP are required to better define the connection requirements should a large pumped storage plant be developed in the Sault/Algoma area.

The third component is replacing the existing 115 kV line supplying Manitoulin Island to 230 kV to enable 400 MW of wind development on the island. The length of that line is about 100 km and the estimated cost is about $90 million.

The latter two components are in the category of enabler lines.

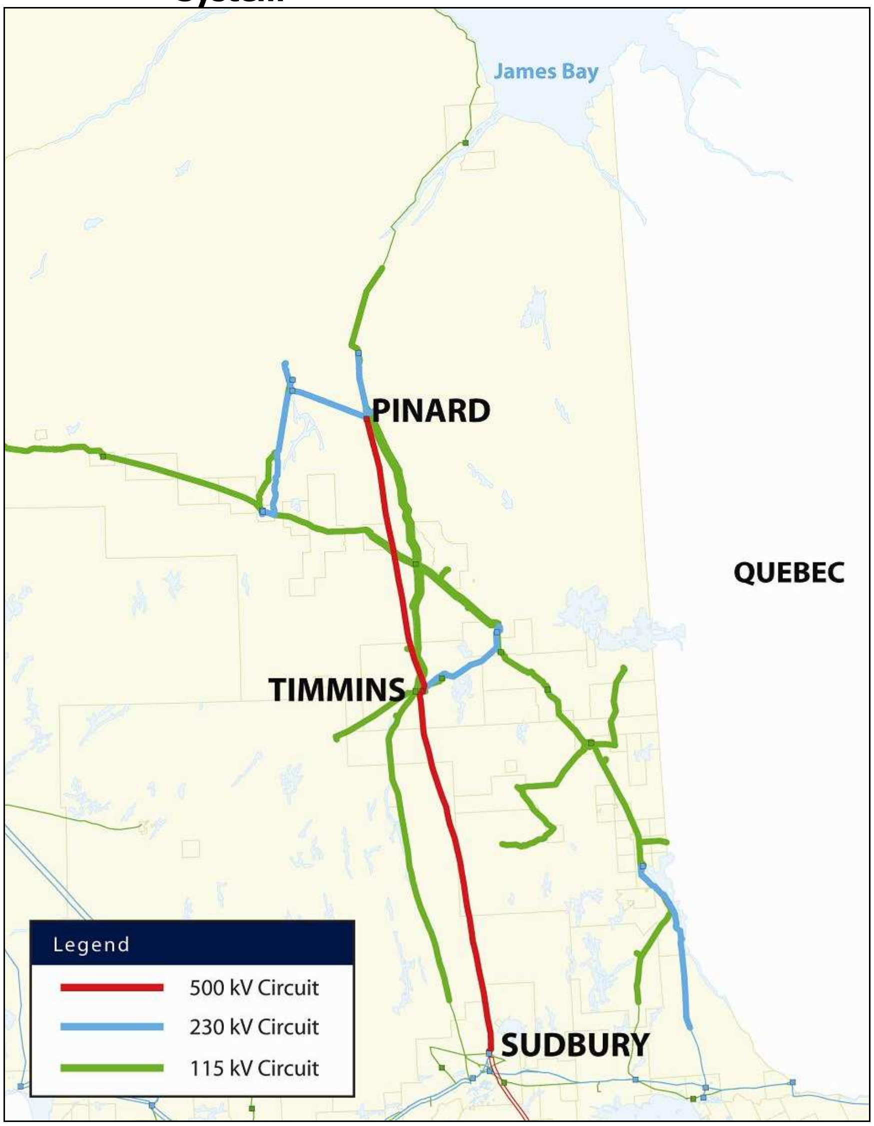
In summary, there has been an increasing level of generation development in this subsystem. With modest reinforcement of the existing transmission system in the area, the natural gas-fired and wind generation expected in the near term, as well as a further 200 MW of development in the Manitoulin/Espanola area, can be transmitted to Sudbury. There is a significant amount of renewable resource potential in this subsystem. Major reinforcement of the transmission path between the Sault/Algoma area and Sudbury is required to realize this potential. The most likely option is a new 500 kV line between the Mississagi station and the Hanmer station. Enabler connection lines in the GLP system and to Manitoulin Island would be required to facilitate the development of renewable resource generation in these locations.

2.3.3 North and East of Sudbury

The bulk transmission system north and east of Sudbury and in the Sudbury area is shown in Figure 2.14.

The transmission system north of Sudbury comprises one 500 kV line connecting Sudbury to Timmins and then from Timmins to the major existing hydroelectric developments on the Abitibi, Mattagami and Moose rivers near Fraserdale. The overall length of this 500 kV line is about 400 km. There is also a long, sparse 115 kV network that connects load centres in this subsystem to the transmission system. These critical delivery paths are highlighted in Figure 2.14.

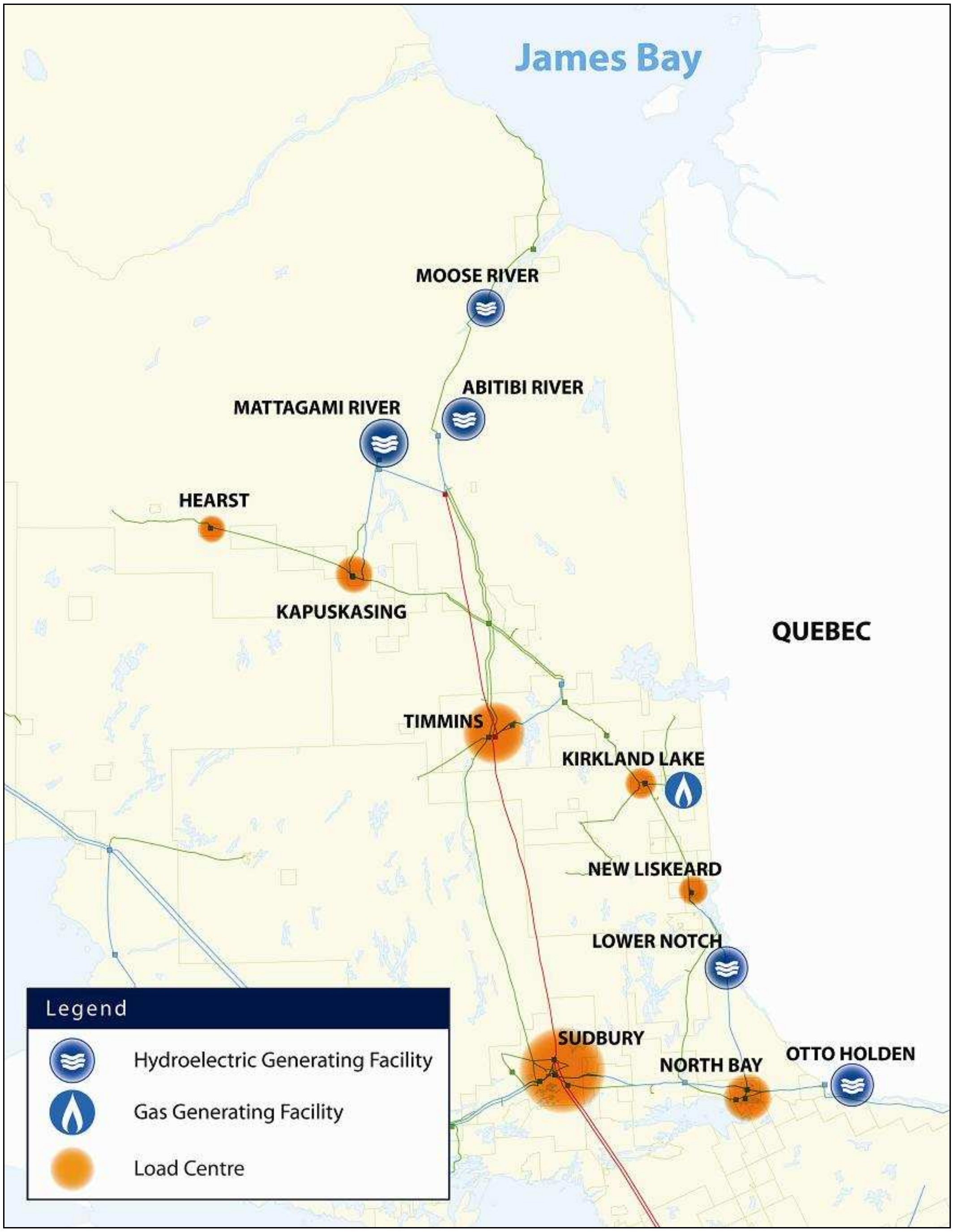
Figure 2.14 – North and East of Sudbury Transmission System



Source: Hydro One Networks Inc. and OPA

The load in this subsystem, including the Sudbury area, totals about 1,190 MW. The major load centres are located at Sudbury, New Liskeard, Kirkland Lake, Timmins, Kapuskasing, Hearst and North Bay. The details are shown in Table 2.3. One of the prominent features of this subsystem is the abundance of hydroelectric peaking resources located north of Timmins on the Abitibi, Mattagami and Moose rivers, as shown in Figure 2.15 and Generation. The peak generation capacity in this area totals 2,205 MW today. Many of the hydroelectric generation plants north of Timmins have limited energy capacity. They are used for peaking purposes and may be off for much of the day.

Figure 2.15 – North and East of Sudbury and Sudbury Area Load and Generation



Source: Hydro One Networks Inc. and OPA

Table 2.3 – North and East of Sudbury Generation and Loads (2005)

North of Sudbury Generation	
Site	**Generation (MW)**
Kirkland Lake	150
Abitibi River	490
Iroquois Falls	130
Mattagami	430
Lower Notch	270
Otto Holden	250
Other	485
Total	2,205

North and East of Sudbury Loads	
Sites	**Load (MW)**
Sudbury	470
Timmins	222
North Bay	149
Kapuskasing	131
New Liskeard	33
Kirkland Lake	23
Hearst	23
Other	129
Total	1,190

Source: IESO and OPA

In planning for the area north and east of Sudbury in the IPSP, there are a number of potential resource developments in the region that will have major implications on the transmission system there. They are:

- incorporation of near-term resources
- development of renewable resources.

Incorporation of Near-term Resources - In addition to the 2,205 MW of existing generation in this subsystem, another 450 MW are possible with the expansion of the Mattagami plants – Kipling, Harmon and Little Long - and the redevelopment of Smoky Falls. This development could be in-service between 2010 and 2012. Furthermore, there are smaller hydroelectric developments that are possible from the Standard Offer Program for Renewable Energy.

The existing transmission system north of Sudbury is just adequate for transmitting the resources located north of Timmins. There is one 500 kV line connecting Timmins and north to Sudbury. The 115 kV underlying network is incapable of backing up the 500 kV line should this line be out of service. Any outage of this critical transmission line under peak transfer conditions requires the use of a special protection scheme to rapidly and automatically disconnect large amounts of generation north of Timmins to maintain system stability. Although this mode of operation is tolerable because the "rejection" involves mostly hydroelectric units (some gas-fired units in the area are also included in the scheme), which are less prone to damage from rapid disconnection than other large generating units, this mode of operation is complex and requires close matching of demand and resources for the scheme to operate correctly.

The addition of the near-term development of the Mattagami and Smoky Falls facilities and the small hydroelectric development in the area will require generation rejection of close to 1,500 MW. This is approaching the current practice of maintaining generation loss in Ontario from a single-element contingency to below 1,500 MW. This is the amount of immediate support Ontario is depending on from its neighbours following such an event. Dynamic reactive power support is also needed in the Timmins and Kirkland Lake areas to maintain and stabilize voltages north of Sudbury. The estimated cost of these facilities is about $60 million.

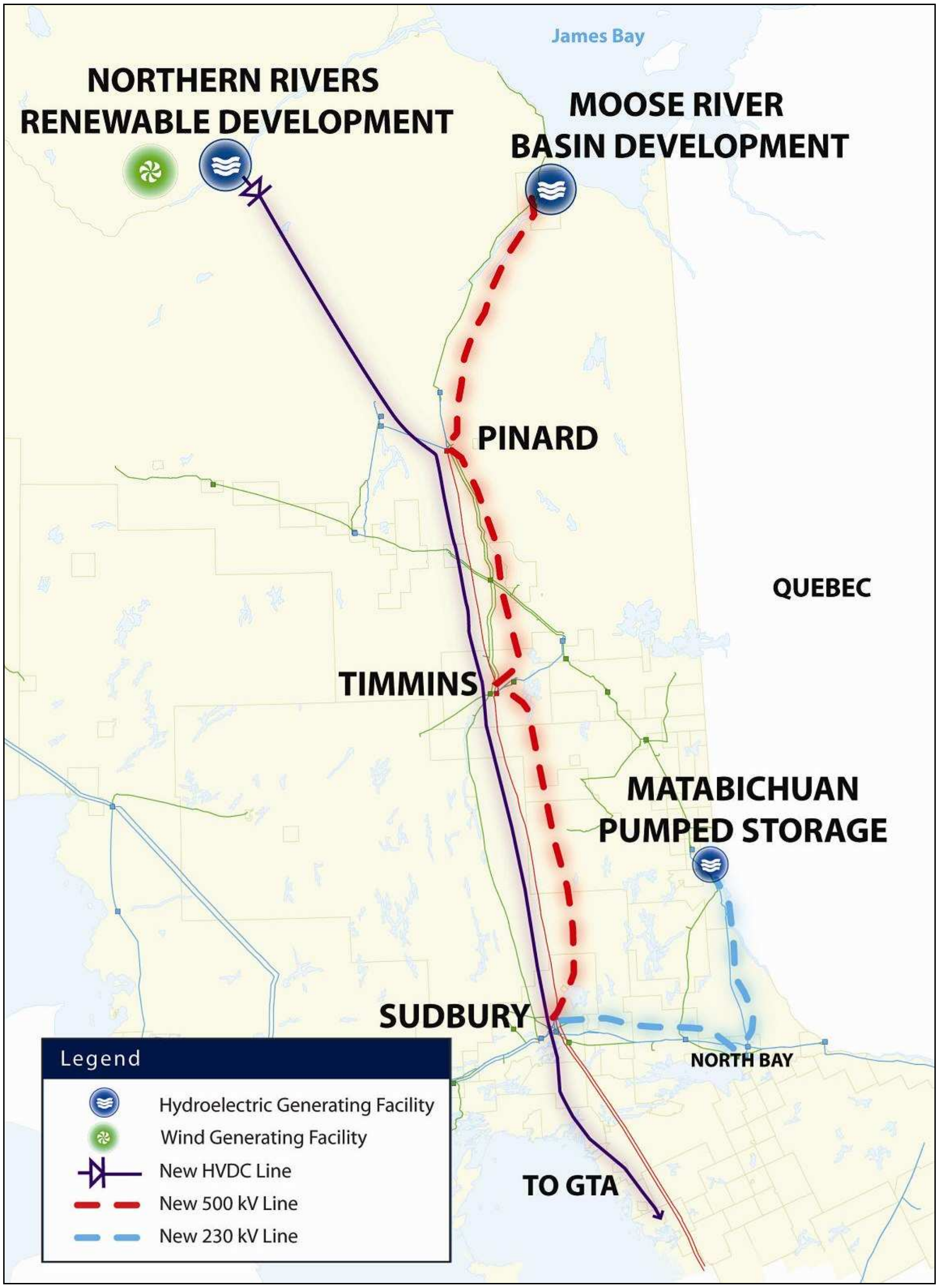
Additionally, the loss of about 1,500 MW for a single-element contingency in the above mode of operation will increase reserve requirements and associated costs for the system.

Development of Renewable Resources - A recent assessment of the hydroelectric generation potential in Ontario concluded that there are good resources in the northern part of northeastern Ontario. Specific major developments identified include a comprehensive development of the Moose River Basin, adding about 1,000 MW and the development of the Northern Rivers – the Albany, Attawapiskat, Winisk and Severn, adding a few thousands of MW. The Albany development, for example, can have a realizable potential of up to 2,000 MW, if the hydroelectric potential there is coupled with the excellent wind generation potential in the area and in consideration of the transmission practicalities. The Moose Basin development could be developed in the 2020 timeframe; the Northern River hydroelectric and wind resources would be developed over the longer term, beyond 2020. All these developments are subject to a co-planning framework with affected First Nations. In addition, there is a potential for about 400 MW of PGS development at Matabichuan, northeast of Sudbury.

The Moose River Basin development will require the construction of a new second 500 kV line between Sudbury and the Moose River Basin, a distance of about 550 km. Preliminary cost estimates indicate this line would cost about $880 million. The development of the Albany River hydroelectric development coupled with wind generation development in the area will require a dedicated connection, most likely an HVDC line, from the hub of the Albany development to Sudbury, a distance of about 650 km, or directly to the GTA, an additional 425 km. This HVDC line with a termination at Sudbury would cost about $900 million.

Development of the pumped storage plant at Matabichuan would require the reinforcement of transmission east and north of Sudbury. One possibility for this reinforcement is a new 230 kV line from Sudbury to North Bay to the New Liskeard area, a distance of about 220 km and a cost of roughly $370 million. These enhancements are shown in Figure 2.16.

Figure 2.16 – North and East of Sudbury Transmission Enhancements



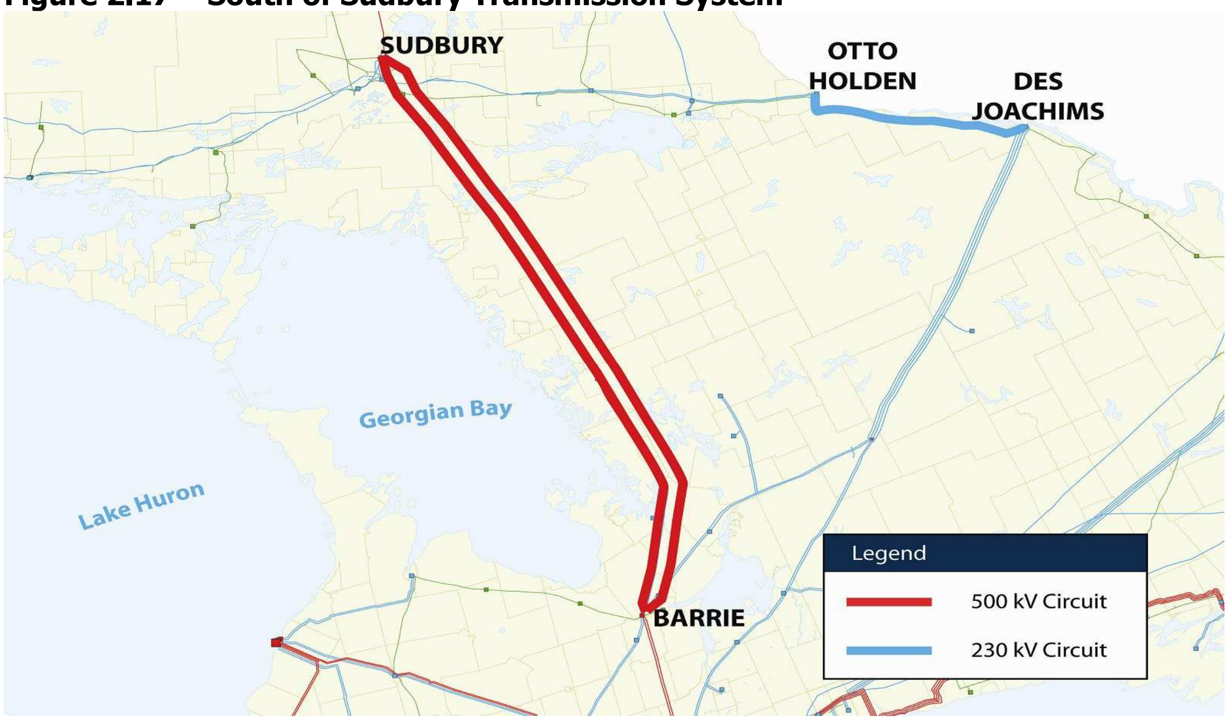
Source: Hydro One Networks Inc. and OPA

In summary, the subsystem north and east of Sudbury is at its limit. With additional generation rejection and dynamic reactive power sources, the development of the Mattagami and Smoky Falls facilities and some small hydroelectric sites can be incorporated. Larger renewable resource development, however, will require major reinforcement of the transmission system north of Sudbury.

2.3.4 Flows South from Sudbury to Barrie

Critical to the further development of Ontario's northern renewable resources is the capacity of the transmission system to deliver large quantities of power first to the Sudbury area, and then from the Sudbury area to the GTA. The former has been covered in the previous three sections of this discussion paper. The latter will be addressed here and in the next section.

Figure 2.17 – South of Sudbury Transmission System



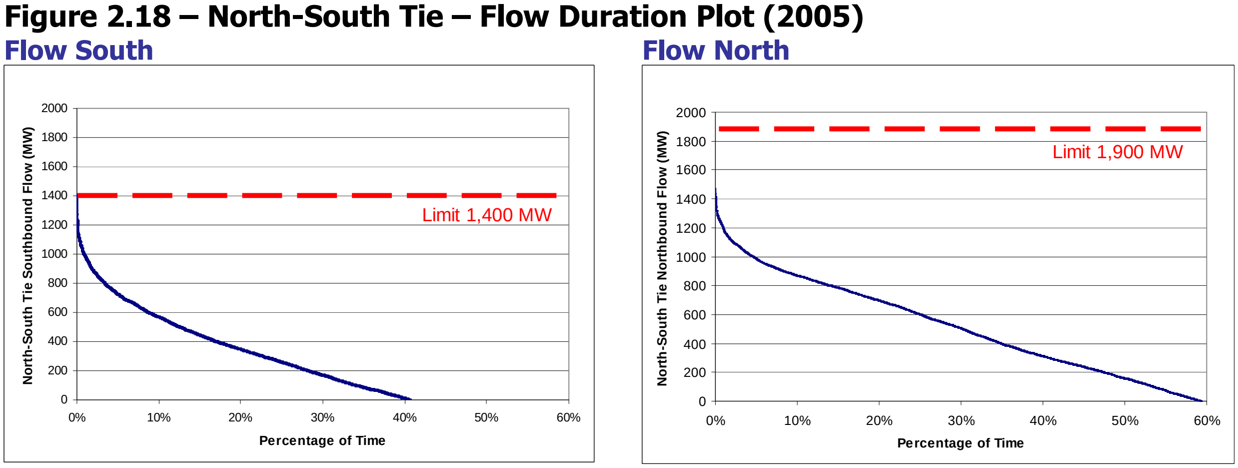
Source: Hydro One Networks Inc. and OPA

The transmission system between the Sudbury area and the Barrie area is shown in Figure 2.17. It comprises two 500 kV lines between Sudbury and Barrie, a distance of about 280 km, and a 230 kV line between the Holden generating station on the Ottawa River near Mattawa and the Des Joachims generating station on the Ottawa River north of Pembroke. Together, these transmission circuits are referred to as the North-South Tie. These critical path components are highlighted in Figure 2.17. The north-to-south transfer capability of this tie is about 1,400 MW today. The capability for south-to-north transfers is about 1,900 MW.[2] With some control actions, such as generation rejection and switching off reactive power control equipment following equipment outages, the North-South Tie has just adequate capability for today's power transfer needs.

Power flows on the North-South Tie vary widely over a year. Figure 2.18 shows the duration and magnitude of the hourly transfers recorded by the IESO for the North-South Tie in 2005. From Figure 2.18, it can be seen that the power transfers on the North-South Tie have a fairly dynamic range – from 1,400 MW flow south to about 1,400 MW flow north over the course of a year. About half of the transfers were southbound, and the other half were northbound. An explanation of this characteristic is that the power flows south when the abundant amount of hydroelectric generation in the northeast is operating, usually during peak hours and during spring run-off periods, and there is excess generation available in the northeast after supplying the load in the region. Conversely, the transfer is typically northbound in the other periods when the hydroelectric generating plants in the northeast are producing minimal power and baseload generation in southern Ontario is supplying the relatively high industrial load in northern Ontario.

As resource development and demand change occur in northern Ontario, the characteristics of the transfer pattern on the North-South Tie will change accordingly. The development of additional resources in the North will increase the southbound flows and decrease the northbound flows.

Figure 2.18 – North-South Tie – Flow Duration Plot (2005)



Source: IESO and OPA

Renewable energy generation developments are occurring in northern Ontario. Some of the major ones that are either in-service, under development or anticipated include Prince I and II wind generation, Umbata Falls and Island Falls hydroelectric developments, the Mattagami

[2] Capability is different for flow in the two directions because of an accompanying difference in system conditions and, consequently, a difference in factors such as applicable contingencies and stability/limits that are included in determining transfer capability.

Extension, the Smoky Falls redevelopment and a combined heat and power project in the Algoma area. Together, these developments total about 775 MW of capacity. With a modest reinforcement consisting of series compensation and voltage support equipment on the North-South Tie near Parry Sound and the extension of generation rejection capability in the northeast, the existing capability of the tie can be increased from 1,400 MW to 2,500 MW, to accommodate the higher transfer level from northern Ontario to southern Ontario. The estimated cost of the near-term transmission enhancements is about $110 million. The earliest in-service date for these enhancements is 2010.

Figure 2.19 – South of Sudbury Reinforcement Options

Source: Hydro One Networks Inc. and OPA

Adding a new single-circuit 500 kV line between Sudbury and the GTA, a distance of about 425 km, would further increase the North-South Tie by about 1,000-1,500 MW, for a total transfer capability in the range of 3,000-3,500 MW. A fourth single-circuit line would increase the capability to the 4,000-5,000 MW range. The cost would be about $800 million for one line, and $1.6 billion for two lines. These reinforcement options can be expected to have long lead times, in the order of five to seven years.

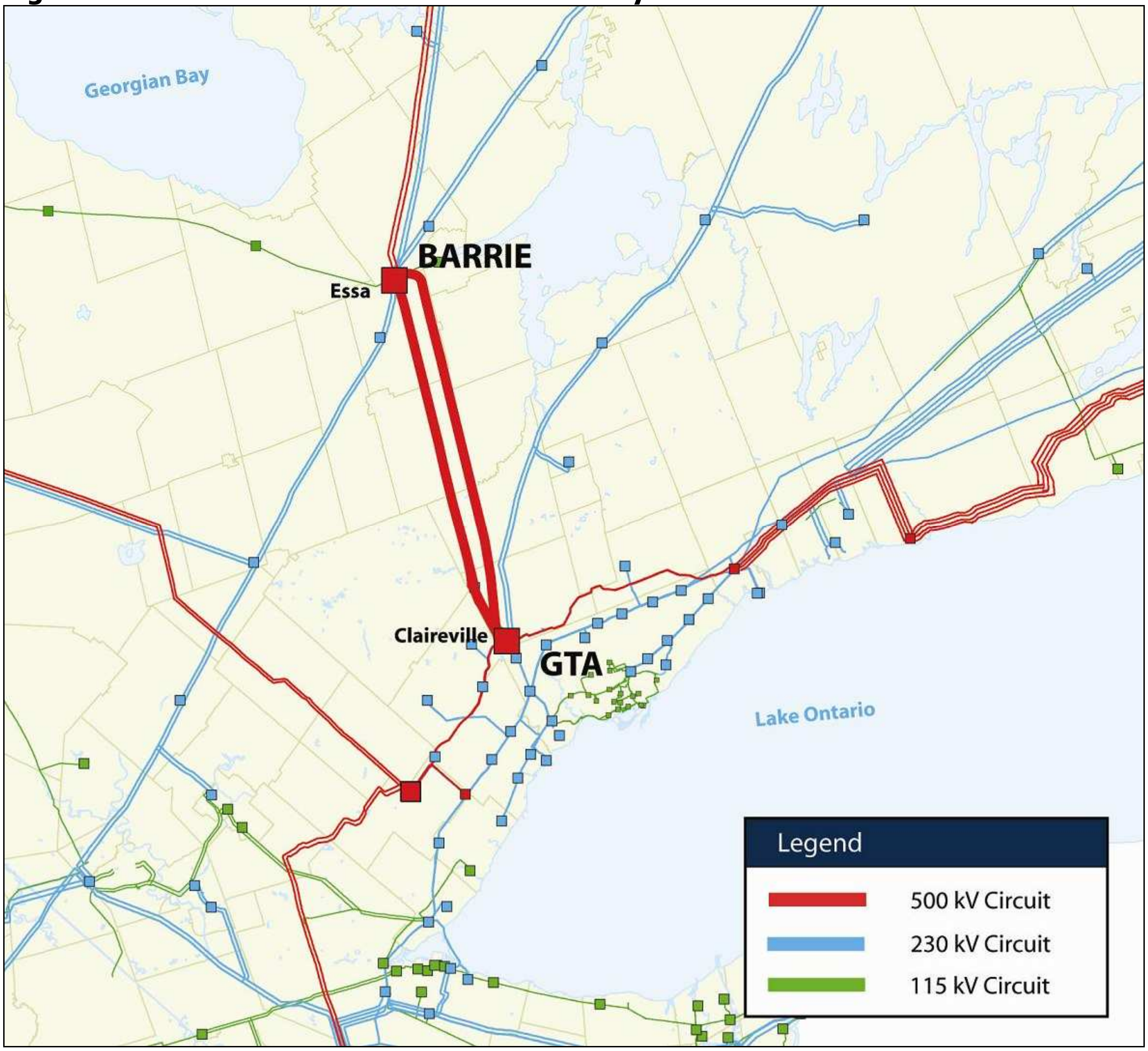
HVDC technologies may also be used for these circuits. Both conventional thyristor-overhead line options and HVDC "Lite"-underground cable options are possible. More studies are required to determine their technical acceptability. The cost of these options is also expected to be higher than the 500 kV alternating current (AC) options.

In summary, further development of renewable resources in northern Ontario will increase the north-to-south transfer on the North-South Tie. Installation of reactive power support facilities in the form of series compensation near Parry Sound will permit a sizeable increase to that capability. This would be adequate for the near-term development, including the extension of the Mattagami plants. Further major development would trigger the need for major reinforcement of the North-South Tie. This includes hydroelectric development in the Moose Basin, the Albany and other northern rivers, wind and hydroelectric development west or east of Sudbury, and other sizeable small hydroelectric, Standard Offer Program renewable energy and combined heat and power (CHP) development. Both alternating and direct current technologies are possible options for this major reinforcement of the North-South Tie. Sufficient lead time of about five to seven years should be allowed for this project, considering its routing through central Ontario and possible termination in the GTA.

2.3.5 Flows South from Barrie to the GTA

The existing transmission system between Barrie and the GTA is shown in Figure 2.20. This system comprises two 500 kV lines from the Essa station west of Barrie to the Claireville station in Vaughan, a distance of about 70 km, as highlighted in the figure. The Essa station is the main high-voltage supply station for loads in the areas of southern Georgian Bay, Barrie, north and west of Lake Simcoe and Parry Sound. The Claireville station is a major station in the GTA, supplying the northern part of the GTA. It also receives supply from the west, including power from Bruce and Nanticoke via the Milton station, and from the east, including power from Darlington and Pickering via the Cherrywood station.

Figure 2.20 – Barrie to the GTA Transmission System



Source: Hydro One Networks Inc. and OPA

The transmission issues associated with this subsystem are:

- having adequate transmission capability to deliver power from northern Ontario to the GTA
- facilitating the development of generation from renewable resources along the eastern shore of Georgian Bay and central Ontario
- providing adequate load supply capacity for the growing load in the southern Georgian Bay/Barrie areas
- facilitating transmission capability to deliver the potential new generation from the Bruce area via the Bruce to Essa 500 kV line should that be the transmission alternative chosen for reinforcing the Bruce transmission system.

Barrie to the GTA Transfer Capability – The path between Barrie and the GTA, which essentially consists of the two 500 kV circuits between the Essa station and the Claireville station, has a north-to-south transfer capability of about 1,700 MW. With a large local load in the Barrie area of about 500 MW, and a limit of about 1,400 MW south from the Sudbury area on the North-South Tie, the existing capacity is adequate. However, a number of potential developments could increase the power transfer on this path, including:

- an increase in the north-to-south transfer capability on the North-South Tie from today's 1,400 MW level to about 2,500 MW, as discussed in the previous section. This will result in an additional 900 MW of power transfer from the north into the Barrie area and from the Barrie area to the GTA
- the development of about 800 MW of wind generation potential on the east shore of Georgian Bay north of Parry Sound and its possible connection to the Parry Sound to Essa transmission line. This would add about 800 MW of power flow on this path
- a potential for an in-feed from a new 500 kV line from the Bruce nuclear plant at the Essa station (will be discussed further in the next section). This would add significant flows of 1,000 MW or more depending on system conditions, on this path.

The power transfer on the Essa station to the Claireville station path could increase by 1,700 MW, assuming no Bruce to Essa line, or to over 2,700 MW with the Bruce to Essa line, which would require the transfer capability of this path to be augmented in order to accommodate the various generation development possibilities.

The first step in increasing the transfer capability of this path is improving the conductor clearances on the Essa to Claireville 500 kV lines. Depending on the extent of the work required (which would be based on a detailed assessment of the physical condition of the lines), about a 500 MW increase to the existing transfer capability could be obtained at a relatively low cost. Beyond this increase, a new line is required between Essa and Claireville to further increase the transfer capability of the Barrie to GTA path. The existing transmission right-of-way has sufficient room for the addition of the third 500 kV line between Essa and Claireville. That third line would increase the transfer capability by another 1,500 MW. The cost for this line would be about $200 million. Beyond these reinforcements, it is assumed that any further increase in the transfer from northern Ontario to southern Ontario would require the construction of one or more North-South lines and the termination of those lines would be in the GTA and not at the Essa station. Otherwise, additional transmission between Essa and Claireville would be required.

East Georgian Bay Renewable Resources – The eastern shore of Georgian Bay north of Parry Sound has been identified as having a large wind generation potential, as shown in Figure 2.21. Over 800 MW of wind generation development is possible. However, the best wind resource locations are far from the transmission system. The closest transmission lines are the North-South Tie 500 kV circuits, which are generally within 25 km of the wind generation sites. Connecting to the North-South Tie is a possibility but not preferred as the output from wind generation in this area would be added to the north-to-south transfers on the North-South Tie. There would also be the need for a major switching and transformation station at the point of connection with the 500 kV lines, and connection lines from this station to the wind generation sites.

Figure 2.21 – Parry Sound Wind Enabler Lines

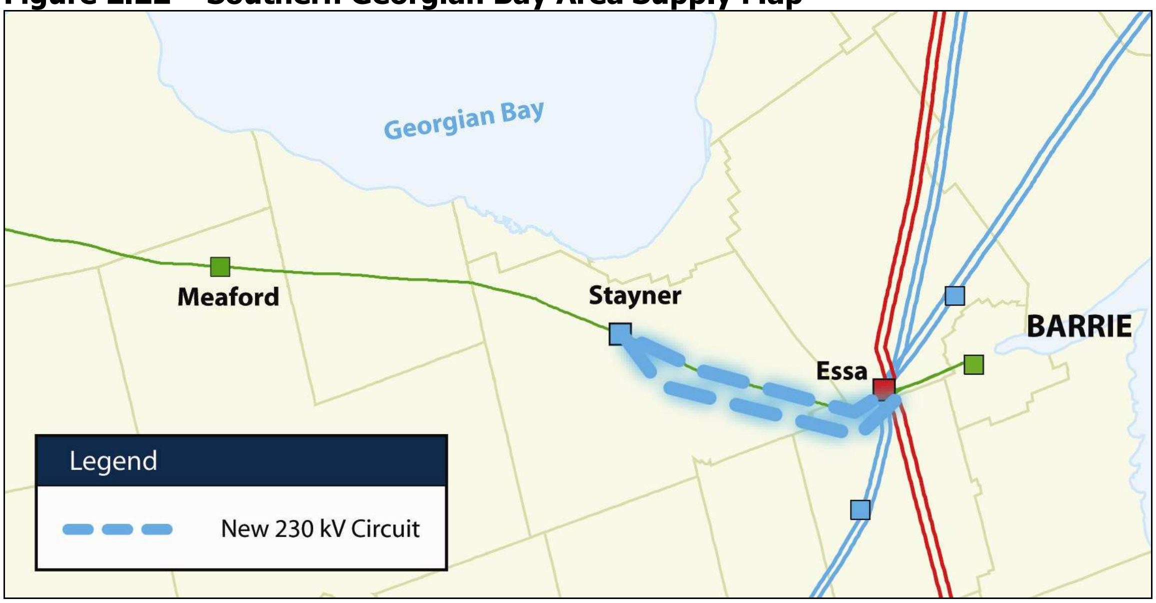
Source: Hydro One Networks Inc. and OPA

The technically preferred option is to extend the Essa station to the Parry Sound station double-circuit 230 kV line along the existing 500 kV North-South right-of-way to a gathering point among the wind generation development sites for their connection as shown in Figure 2.21. There is room available on the existing 500 kV right-of-way to do this. This line would be in the category of an enabler line as discussed earlier. The length of this line is about 100 km. The cost is about $130 million. A lead time of about five years is required. The advantage of this option is that about 800 MW or more of wind generation would be connected directly to the Essa station and not use any of the North-South Tie transfer capability.

Local Area Supply Reliability – There is one urgent local area reliability reinforcement project in this subsystem. It is related to the southern Georgian Bay area.

A study assessing the need and solutions for southern Georgian Bay concluded that, because of robust growth in this area and in the surrounding Barrie area, demand in southern Georgian Bay has reached the capacity of its 115 kV supply. The preferred solution is to convert a 115 kV line from the Essa station west of Barrie area to the Stayner station in Clearview to 230 kV operation (Figure 2.22). This project, which is being implemented by Hydro One Networks, has undergone public consultation and has submitted a leave to construct application to the OEB.

Figure 2.22 – Southern Georgian Bay Area Supply Map



Source: Hydro One Networks Inc. and OPA

In summary, the transmission path between Barrie and the GTA is adequate today. However, with increasing level of renewable energy generation developments in northern Ontario and along the east shore of Georgian Bay, the level of power transfers on this delivery path will increase significantly. Termination of the new 500 kV line from Bruce in the Barrie area will exacerbate this further. Some increased capability can be obtained from minor improvements, but eventually new major transmission reinforcement will be required. Most likely, this would be the addition of a new 500 kV line along the existing right-of-way. Additionally, extending the existing 230 kV line from Parry Sound, as an enabler line, to the wind-rich area along the eastern shore of Georgian Bay would facilitate the development of about 800 MW of wind generation in that area. There is one local area reliability project in the area related to the supply to the southern Georgian Bay area. This project is proceeding ahead of regulatory review of the IPSP because of its urgency.

2.3.6 Bruce/Southwestern Ontario to the GTA

Bruce/Southwestern Ontario (SWO) is the region of southern Ontario that lies west of the GTA and the Barrie area. The transmission system in SWO, which includes that in the Bruce area, is shown in Figure 2.23. The critical elements of this Bruce/SWO subsystem are:

- four 500 kV circuits on two tower lines out of Bruce – two circuits to the London area and two circuits to the GTA
- one 500 kV circuit from the London area to Nanticoke
- two 500 kV circuits from Nanticoke to the GTA
- the 500 kV transformer stations at Bruce (north of Kincardine), Longwood (west of London), Nanticoke (east of Port Dover) and Middleport (east of Brantford)
- an underlying 230 kV network.

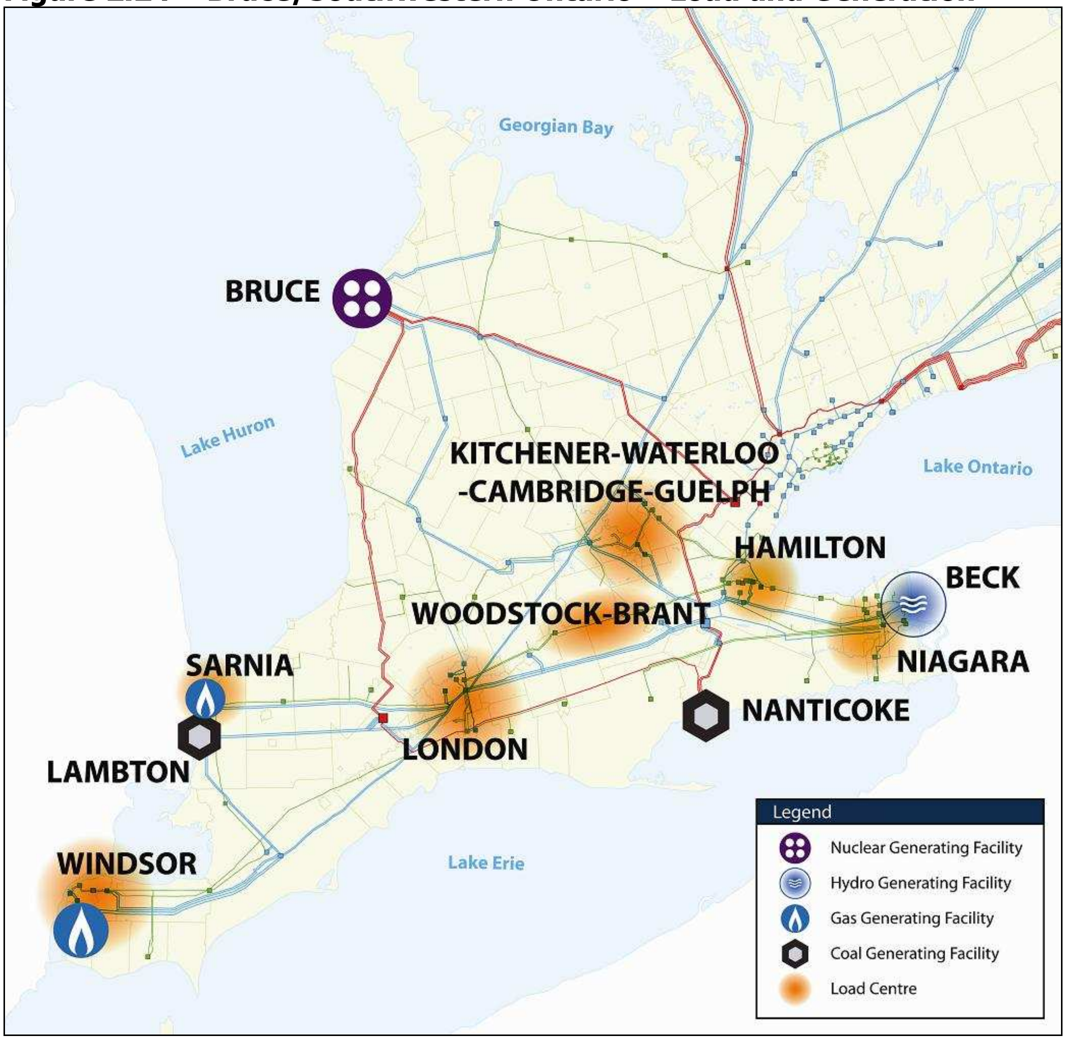
These facilities are highlighted in Figure 2.23.

Figure 2.23 – Bruce/Southwestern Ontario Transmission System

Source: Hydro One Networks Inc. and OPA

The Bruce/SWO subsystem has a number of large generation and load centres. These load and generation centres are shown in Figure 2.24.

Figure 2.24 – Bruce/Southwestern Ontario – Load and Generation



Source: Hydro One Networks Inc., IESO, and OPA

The major generation centres in Bruce/SWO include Bruce (5,060 MW), Nanticoke (3,945 MW), Lambton (1,972 MW) and the Beck Niagara Complex (2,006 MW). The generation capacity in the area totals about 15,000 MW. This is summarized in Table 2.4.

Table 2.4 – Bruce/Southwestern Ontario Generation, Load and Interconnection (2005)

Bruce/Southwestern Ontario Generation	
Zone	**Generation (MW)**
Bruce	5,060
Nanticoke	3,945
Lambton	1,972
Beck	2,006
Windsor area gas	739
Sarnia	510
Other	746
Total	14,978

Bruce/Southwestern Ontario Loads	
Zone	**Load (MW)**
Windsor/Essex	1,000
Sarnia	800
London	750
KWCG	1,400
Hamilton	1,300
Woodstock/Ingersoll	195
Brantford/Brant	250
Niagara	1,020
Other	2,100
Total	8,815

Interconnections	
Michigan	**Capability (MW)**
Import - Summer	1,550
Export - Summer	1,950
Import - Winter	1,750
Export - Winter	2,200
New York at Niagara	
Import - Summer	1,300
Export - Summer	1,300
Import - Winter	1,650
Export - Winter	1,950

Source: IESO and OPA

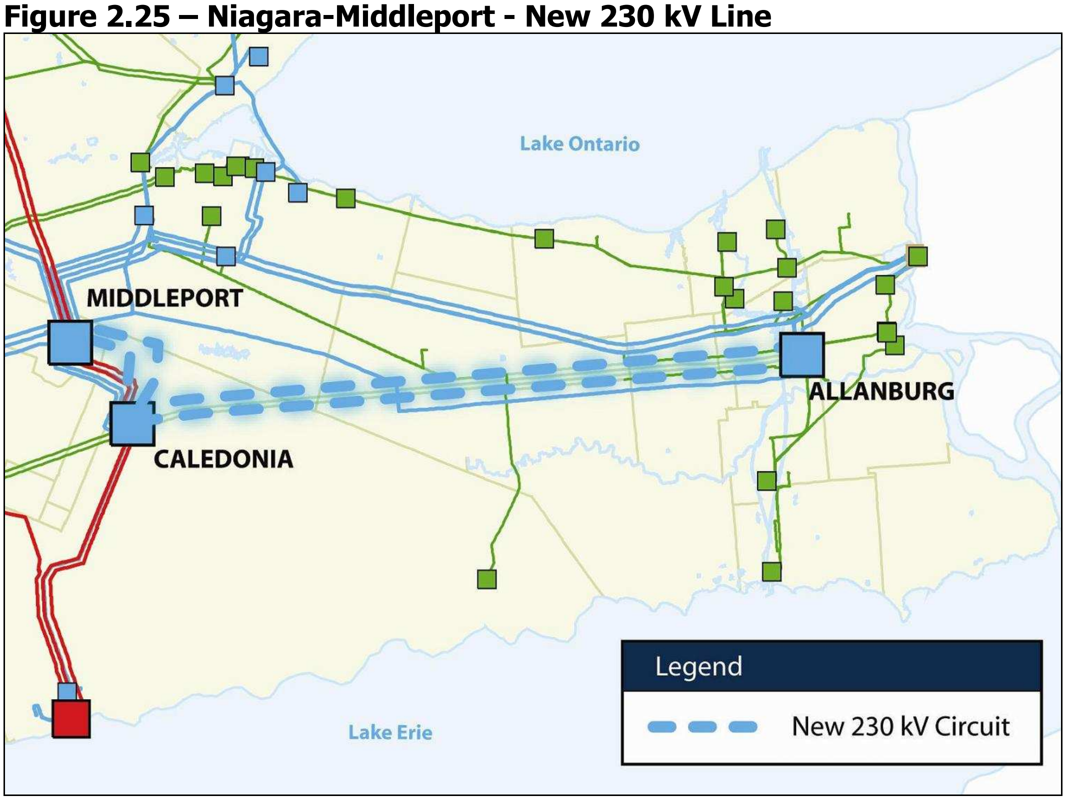
The large load centres that are located in SWO are Windsor (1,000 MW), Sarnia (800 MW), London (750 MW), Kitchener-Waterloo-Cambridge-Guelph (1,400 MW) and Hamilton (1,300 MW). These are summarized in Table 2.4. The peak demand recorded for SWO was about 8,800 MW in the summer of 2005.

As well, there are major high-capacity interconnections with New York and Michigan. A summary of the interconnection capabilities in SWO is shown in Table 2.4.

Unlike the system in northern Ontario, which is generally radial in nature, the transmission network in SWO is highly integrated (or "meshed"). With this type of system, and the strong connection it has with the systems in the GTA, Barrie area, New York and Michigan, the availability and performance of each major element in this system, in particular the 500 kV facilities, can affect the integrity of the entire network in southern Ontario as well as those in neighbouring jurisdictions.

The last major expansion of the SWO transmission system was carried out in the early 1990s with the completion of the 500 kV network connecting Bruce, London and Nanticoke, and other reinforcements on the 500 kV network. Currently, Hydro One Networks is completing the construction of a new double-circuit 230 kV line from the Niagara area to Middleport station, as shown in Figure 2.25, to provide relief to the congestion on the delivery path from the Niagara area to the Hamilton area. The existing SWO transmission system is generally capable of supporting six units in operation at Bruce, full generating capacity available at Nanticoke and Lambton and up to 3,000 MW of simultaneous imports on the interconnections with the U.S. As development occurs in SWO, such as additional generation at Bruce or reduction of operating units at Nanticoke, the transmission system serving this area will be challenged in a manner for which it was not designed. Certain modifications and reinforcements to the Bruce/SWO transmission system will be necessary to maintain system reliability.

Figure 2.25 – Niagara-Middleport - New 230 kV Line



Source: Hydro One Networks Inc. and OPA

The Bruce/SWO transmission system will need to evolve to address the following transmission challenges:

- adequate transmission capability out of the Bruce area
- reactive power support to maintain voltages in SWO
- transmission capability west of London
- adequate load supply capacity for the growing load in SWO
- facilitating the development of renewable energy generation in SWO.

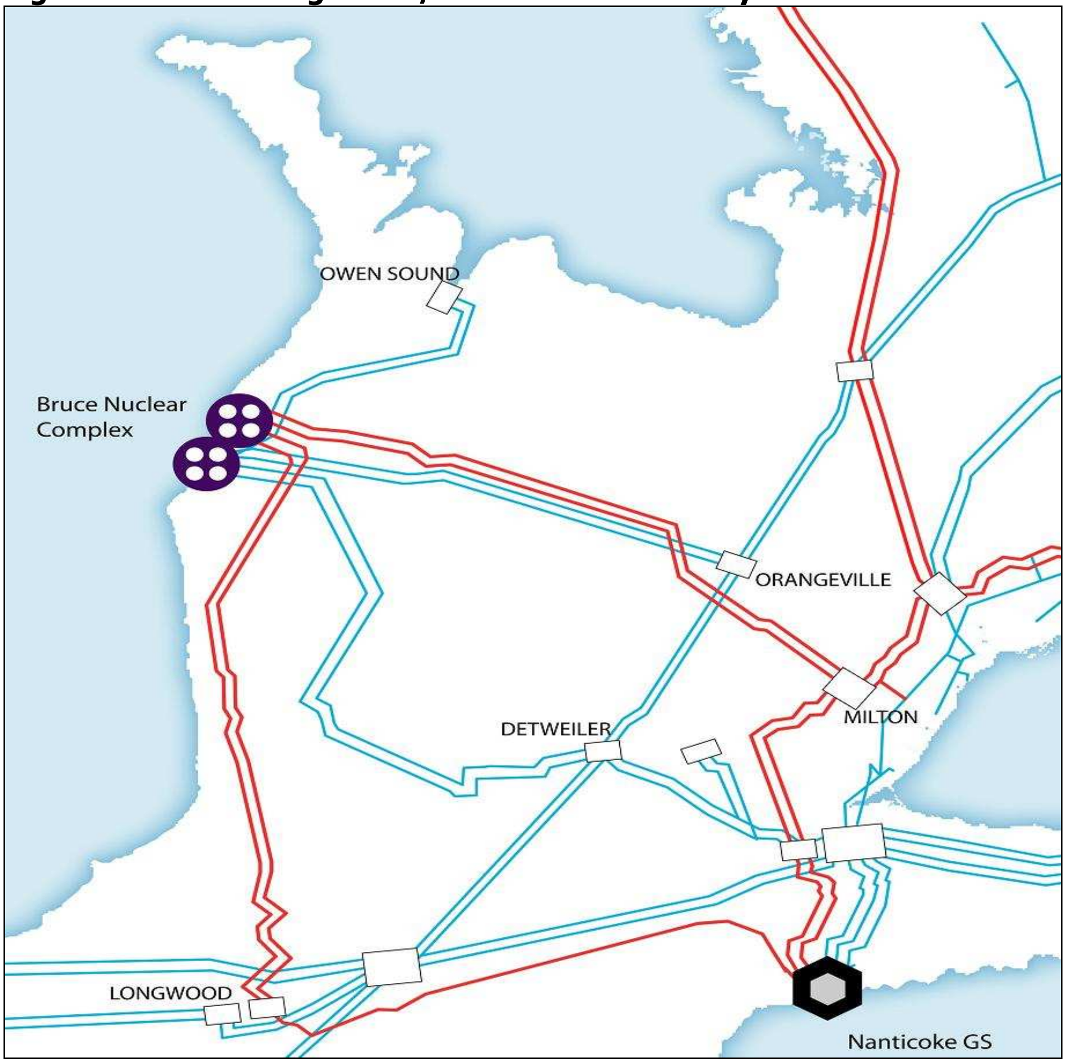
The transmission between the Niagara and the Hamilton areas has previously been identified as one of the congested paths in Ontario. Hydro One Networks is constructing a new double-circuit 230 kV line between the Allanburg station near Niagara Falls and the Middleport station west of Hamilton. The additional capacity provided by this line will eliminate the congestion that has been experienced along this delivery path.

Canadian Niagara Power Inc. is currently exploring the feasibility of a new 115 kV interconnection with New York in the Fort Erie area. The higher intertie capability with New York in the Niagara area as the result of this new interconnection can be accommodated by the increased transmission capability between the Niagara and the Hamilton area as discussed above.

Transmission Capability out of the Bruce Area – The transmission system that connects the Bruce area to the rest of the Ontario transmission network comprises one double-circuit 500 kV line from the Bruce site to the Milton station west of Toronto, one double-circuit 500 kV line from the Bruce site to the Longwood station (west of London), and three double-circuit 230 kV lines connecting the Bruce site to stations in the Kitchener, Orangeville and Owen Sound areas, as shown in Figure 2.26.

Depending on system conditions, this system has the capability to transmit between 4,700 MW and 5,000 MW of generation from the Bruce area.

Figure 2.26 – Existing Bruce/SWO Transmission System



Source: IESO and OPA

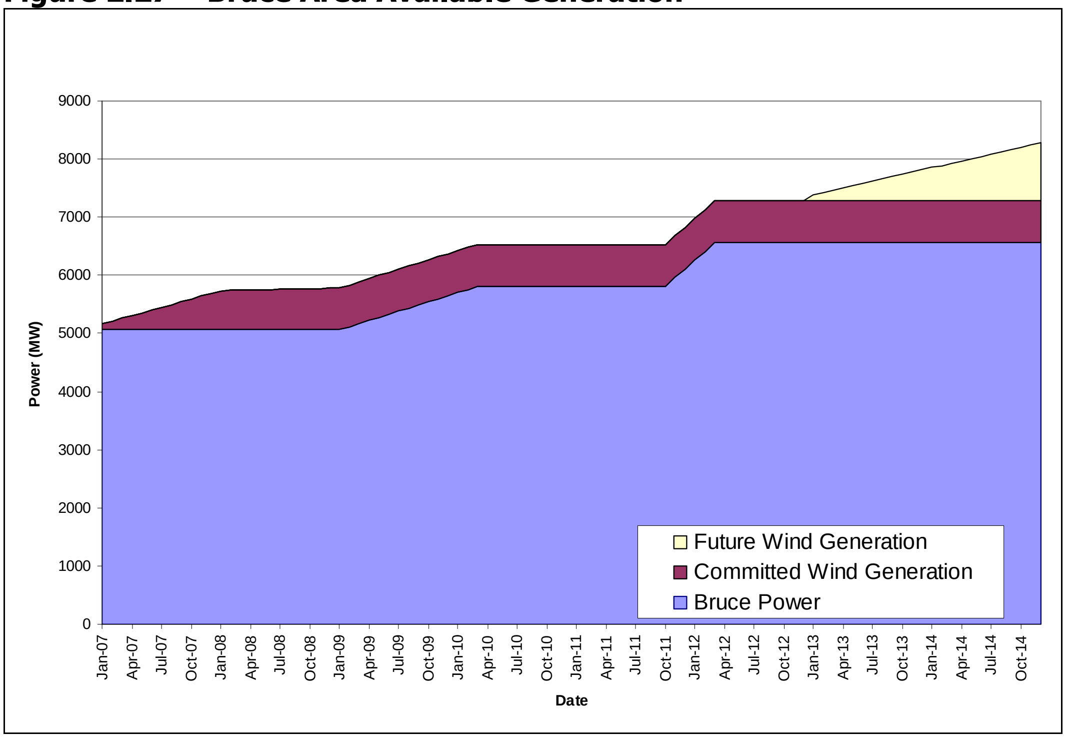
Resources in the Bruce Area – The generation at the Bruce complex totals about 5,060 MW - four 890 MW nuclear units at Bruce B and two 750 MW units at Bruce A. With the approximately 725 MW of wind generation committed for the Bruce area, which is scheduled to come into service in the next few years, the total generation available in the Bruce area will be up to 5,785 MW by 2009.

Additional generation will be added in the Bruce area in 2009 when Bruce Power refurbishes and returns to service units 1 and 2 at the Bruce A nuclear plant. These units have been non-operating since the early 1990s. Bruce A units 1 and 2 will add about 1,500 MW of base-load generation to the system in 2009 (both units will be synchronized to the system in that year). Coincident with the return of units 1 and 2, Bruce Power is scheduling the outage of other units at the Bruce A plant for extended maintenance work. As a result, between 2009 and the end of 2011, there will effectively be an equivalent of one more Bruce unit or about 750 MW added to the Bruce system. This increases the total generation available in the area to about

6,535 MW in that period. By 2012, with the completion of the maintenance work, all eight Bruce units are expected to be in operation. This will increase the Bruce area generation to about 7,285 MW.

Additionally, a recent study conducted by the OPA for the IPSP identified a significant wind generation potential in the Bruce area. Another 1,000 MW or more of wind generation is possible. Thus, with full development of the wind potential in the Bruce area, total generation could reach 8,300 MW. The increasing levels of generation available in the Bruce area to 2012 and beyond are shown graphically in Figure 2.27.

Figure 2.27 – Bruce Area Available Generation



Source: IESO and OPA

Need and Transmission Reinforcement Plan for the Bruce Area – As discussed, by 2009, with the addition of the 725 MW of committed wind generation in the Bruce area and the return of Bruce units 1 and 2, the available generation in the Bruce area will exceed the existing transmission capability for transmitting power from the Bruce area to the rest of Ontario. Without interim measures or reinforcement to the Bruce transmission, output from the Bruce nuclear units and/or wind generating units in the area will have to be curtailed to operate within the capability of the Bruce transmission system.

Thus, there is a need to reinforce the Bruce transmission system:

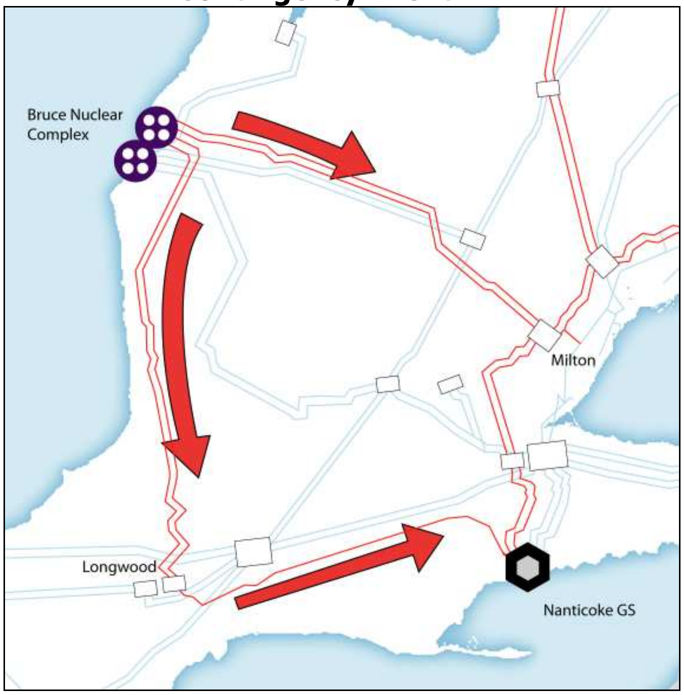
- to permit full deployment of the committed resources in the area with the return of Bruce A units 1 and 2 and the addition of about 725 MW of wind generation in the Bruce area
- to be in-service by 2011/2012 in order to eliminate or minimize the use of interim mitigation measures
- to enable the development of potential new renewable resources in the Bruce area.

The overall plan for increasing the transmission capability from the Bruce area consists of various elements including: commencing the work on a new 500 kV transmission line from Bruce to Toronto (either terminating at the Milton station or the Essa station), implementing near-term reinforcements (230 kV line uprating and a combination of static and dynamic shunt compensation), providing interim measures (GR and/or series compensation) and restricting new generation in the Bruce area until the transmission line is built. These actions will permit committed and new generation to be added to the Bruce area as scheduled, with minimum need for curtailment and congestion costs and provide transmission capability for incorporating future resources in the Bruce area.

Near-term Transmission Reinforcements in the Bruce Area – Some moderate near-term transmission reinforcements of the Bruce transmission system are possible, namely uprating the Hanover to Orangeville 230 kV circuits, and installing 230 kV static and dynamic reactive compensation facilities at Middleport, Detweiler and Nanticoke stations to maintain adequate system voltages. These reinforcements would increase the capability of the Bruce transmission system to about 5,385 MW, at a cost of about $100 million. Two to three years are required to have these facilities in-service.

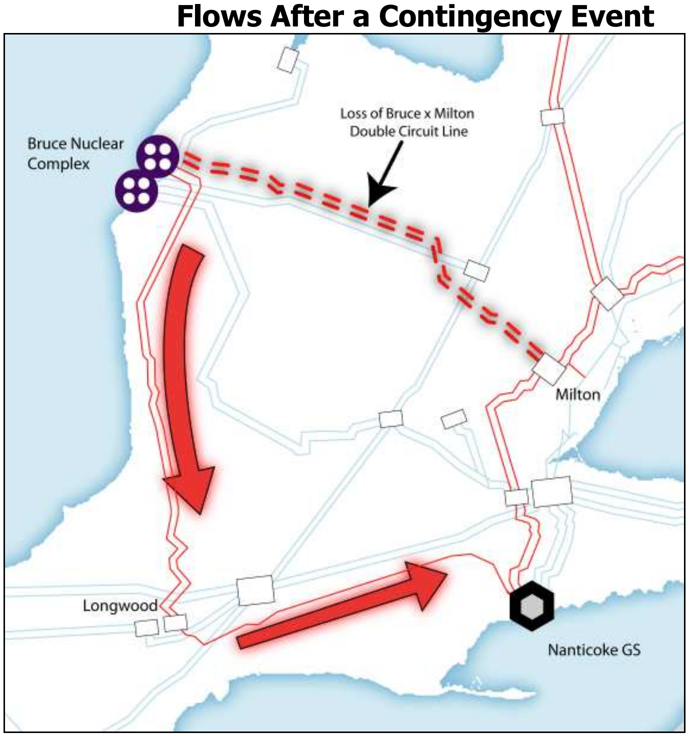
Long-term Transmission Reinforcements in the Bruce Area – The amount of power that can be transferred out of the Bruce area is dictated by the need to maintain transient stability, voltage stability and safe equipment loading following an outage to the Bruce to Milton/Claireville 500 kV transmission line. Figure 2.28 and Figure 2.29 illustrate power flows on the Bruce/SWO system before and after this critical outage. Power that was flowing on the Bruce to Milton/Claireville line to the GTA is re-directed immediately and automatically to the Bruce to London and London to Nanticoke lines. This “indirect” path through London is longer and weaker (note that there is only a single circuit between London and Nanticoke while all the other segments have two circuits). Furthermore, any power that flows into London from the Sarnia and Windsor areas is superimposed on the Bruce flow on the London to Nanticoke path to the GTA which further increases the loading on this section of the transmission path to the GTA.

Figure 2.28 – Bruce/Southwestern Ontario Power Flows Before a Contingency Event



Source: IESO and OPA

Figure 2.29 – Bruce/Southwestern Ontario Power Flows After a Contingency Event



Source: IESO and OPA

Therefore, the basic requirement of any new transmission reinforcement option for addressing the need of the Bruce system is to reinforce the 500 kV path from the Bruce site to the GTA.

This can be done in two ways:

- provide another 500 kV line along the "direct" path from Bruce to the GTA (a distance of about 180 km)
- reinforce the "indirect" path through London by building a second line from London to Middleport or Nanticoke (a distance of about 160 km).

Results from technical studies indicate that reinforcing the "direct path" from Bruce to GTA is far superior in terms of transfer capability and system performance than reinforcing the "indirect" path. In fact, the London reinforcement alternative requires adding major reactive power support devices (series capacitors) as part of the system reinforcement, just to have sufficient transfer capability for the eight Bruce units and 725 MW of wind generation. For this reason, and considering the criticality of this system (one-quarter to one-third of Ontario's generation could be located in this area), the ever-increasing need to have greater transfer capability for this area (to allow for equipment outages and further resource additions) and the need to reduce the operating complexity of this system, the London alternative, although technically possible, is not a suitable alternative for reinforcing the transmission capability out of Bruce. The preferred solution is a new 500 kV line from the Bruce to the GTA along the "direct" path.

In consideration of the provincial land use policy, routing the new line along an existing right-of-way is more feasible, and is expected to require less time and pose less risk of delay than a line along a new corridor. With this assumption, the options for routing the new Bruce to GTA line are narrowed to the following two possibilities:

- the Milton option – from Bruce, follows the existing Bruce to Milton/Claireville 500 kV line right-of-way to the Milton station
- the Essa option – from Bruce, follows the existing Bruce to Milton/Claireville 500 kV line right-of-way until near Luther Lake northwest of Orangeville; then follows the Bruce to Orangeville 230 kV line right-of-way to Orangeville; then follows the Orangeville to Essa 230 kV line right-of-way to the Essa station in the Barrie area.

These routing options are shown in Figure 2.30.

Figure 2.30 – Bruce to Essa and Bruce to Milton - New 500 kV Lines

Source: Hydro One Networks Inc. and OPA

The Milton option has technical advantages over the Essa option of:

- a greater increase in transfer capability and the ability to incorporate more resources in the Bruce area
- no impact on the Barrie to GTA path (the Essa option consumes about 1000 MW of transfer capability along this path, which could lead to the advancement of the third line between the Essa station and the Claireville station).

Both options are estimated to cost about $600 million. They will have different land and community impacts, which are to be determined at the environmental assessment stage.

Two other routing options were also considered initially - termination of the new Bruce line at the Kleinburg station located north of Toronto on the Essa to Claireville corridor, and the “Crief” future station site just east of Guelph near the 401 Highway. Since both required sections of new right-of-way and the performance of these configurations would be similar to the Milton option, these options were not considered further.

Detailed studies are ongoing at this time to assess the technical, economic and environmental aspects of the Milton and Essa options. Because of the urgency of having this line in-service as soon as possible, the environmental assessment and OEB approvals for this project will be sought ahead and independent of the IPSP approval.

The above alternatives are based on the 500 kV alternate current (AC) technology currently used for power transmission in Ontario. There have been proposals for the use of HVDC technology for providing additional transmission capability out of Bruce. Typically, HVDC technology is best suited for long-distance, point-to-point transmission applications, such as the high-capacity East-West Tie for the northwest discussed earlier. It is also more suitable for undergrounding or underwater applications. Although the HVDC option is technically feasible for addressing the need at Bruce, the much higher cost - 50 to 100 percent higher for the same capacity – and pushing the envelope on a relatively new technology for such a critical part of the system, make this option less attractive than the well-established AC options.

Interim Measures for the Bruce Transmission System – Although another 500 kV line from Bruce to the GTA is the long-term solution for increasing the transmission capability out of the Bruce area, it is not expected that this line could be in-service before the end of 2011 because of the extensive lead time required for a project of such scope. In the meantime, to minimize potential congestion costs that would be incurred in the Bruce area starting in 2009 and continued until the in-service of this new line, interim mitigation measures are being considered and action plans developed. These measures, in addition to the 230 kV line uprating and shunt capacitor banks and dynamic reactive power installations discussed earlier, are:

- providing generation rejection of up to two units at Bruce or in combination with wind generation in the Bruce area
- installing 30 percent series compensation on the Bruce to Longwood and Longwood to Nanticoke 500 kV circuits
- restricting further generation development in the Bruce area until the transmission is reinforced.

The provision of interim measures to increase the transmission capability from the Bruce area is not a substitute for the need of a new 500 kV line from Bruce to the GTA. These measures are acceptable only as short-term, stop-gap measures until the new line is in place. Each of these measures and, more importantly, collectively in their application, increases the complexity of a critical part of the Ontario network and the associated impact on the neighbouring interconnected systems. Compounding this is the fact that the transmission assets in Ontario are aging, requiring more frequent and longer outages for maintenance and repairs. The Bruce/SWO transmission system is also being used to a greater extent because of load growth and generation changes (e.g., coal-fired unit phase-out, new gas and renewable resources). Increasingly, it is essential that adequate reactive power supply and voltage regulation capability be provided for this system. Thus, considering all these aspects, operating the Bruce system to its extended capability with the interim measures has to be for a short duration only. Nevertheless, the interim measures can increase the capability of the existing Bruce system and reduce the cost of potential congestion before the new Bruce line is in service. They are appropriate if used judiciously in the manner discussed.

The first interim measure considered is generation rejection (GR). It is a measure that temporarily disconnects generating units in a pre-designed, controlled manner if a major transmission line is taken out of service by a fault from a lightning strike or a tornado. Generation is typically disconnected for a short period of time. Ontario deploys this throughout the province, and has deployed GR at Bruce for many years. GR operated infrequently at Bruce. As intended, it results in infrequent temporary disconnection of generators following an outage of a critical facility on the transmission system. Its use is generally accepted for applications where the failure of such a system does not impact the interconnected network, such as the system north of Sudbury, when equipment is out-of-service for maintenance, or its use is temporary until a more permanent solution that does not rely on GR comes in service (as was the case for the previous use of GR for Bruce in the 1980s).

Approval from the NPCC for GR is required because coordination is required to avoid impacts on the reliability and operation of the overall interconnected system. In this case, for the GR of two Bruce units, there would be a reliance on about 1,500 MW of support from interconnected jurisdictions immediately following the GR action. The cost of an expanded GR scheme is related to the work required to modify the existing Bruce Special Protection System - from $5 million for an upgrade to $50 million for a major refurbishment of the scheme.

Studies by the IESO indicate that GR of up to two Bruce units will increase the effective transfer capability out of Bruce to about 6,700 MW. This is sufficient to eliminate the need to curtail generation in the Bruce area because of transmission limitations in the 2009 to 2011 period. Thus, GR is being proposed for use starting in 2009.

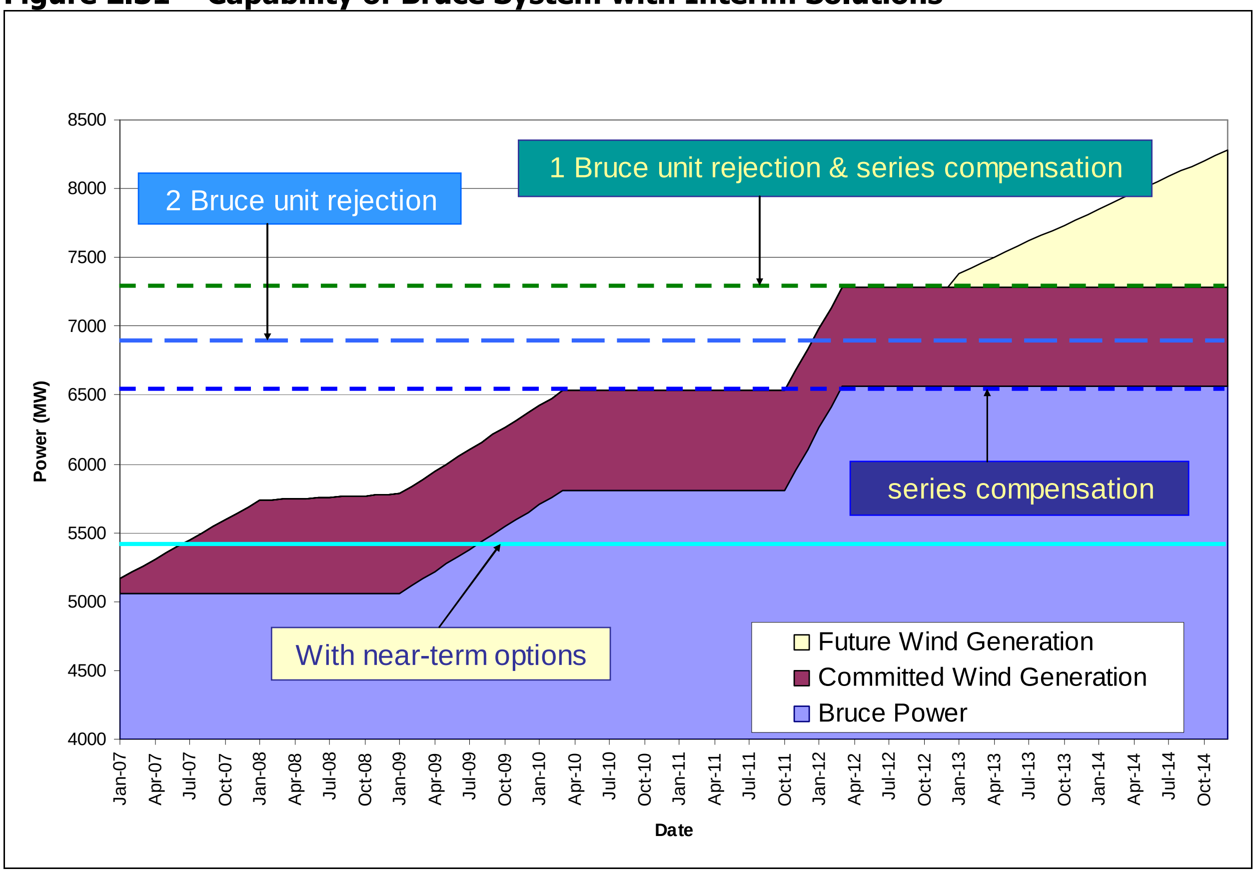
A second interim measure being contemplated for the Bruce area is series compensation. Studies by the IESO have indicated that series compensation is effective in increasing the Bruce transfer capability to about 6,300 MW without the need for GR and is just sufficient for the generation in the Bruce area in the 2009 to 2011 period. Series compensation is not in use in Ontario at this time, but is used in many places around the world, including the transmission systems in British Columbia and Quebec. It is typically used in system applications that are less complex and less tightly interconnected than the Bruce system, with less impact on neighbours. There are a number of considerations that must be well understood as the use of this technology is explored for the Bruce system. As it is being considered for a critical part of the Ontario system, due diligence on the technology and its performance will be conducted, including eliminating potential adverse system effects and potential risks to reliability. As well, major modifications are required to the existing relaying and protection systems in SWO to accommodate the series compensating facilities. Series compensation would also introduce new and complex operation and maintenance procedures for the asset owners.

The capital cost of 30 percent compensation of the Bruce to Longwood and Longwood to Nanticoke circuits is about $100 million. A station at the mid-line point of each of the lines would be required. The siting of the series compensation stations would be subject to the environmental approval process. A lead time of three years is required for their installation. At this time, the OPA, with the support of Hydro One Networks and the IESO, is undertaking a technical due diligence study to ascertain the suitability and risk of employing series compensation for the Bruce/SWO network. Following the completion of the study early next year, and assuming a positive result, the decision on whether to proceed with the series compensation would be made.

In the event the new line is delayed beyond the end of 2011, the use of either GR or series compensation alone would not provide sufficient transfer capability to transmit all the power out of the Bruce area when all eight Bruce units are available in 2012. The IESO studies indicate that the combination of GR and series compensation would provide sufficient capacity for transmitting the committed resources in the Bruce area to the Ontario grid should the new line be delayed. However, there would not be additional transmission capability for adding further resources in the Bruce area until the new Bruce transmission line is in-place.

The capability of the Bruce system with these interim solutions is shown in Figure 2.31.

Figure 2.31 – Capability of Bruce System with Interim Solutions



Source: IESO and OPA

The third interim measure is to restrict further generation development in the Bruce area. This will be reviewed over time as system reinforcements are implemented.

At this time, work is proceeding in all the different areas identified– short-term solutions, interim measures and long-term solution – by Hydro One Networks, the IESO and the OPA to increase the capability of the Bruce/SWO transmission system to meet the anticipated increases in generation capacity in the Bruce area over the next few years.

Reactive Power Support in SWO – The generation capacity at Nanticoke totals about 4,000 MW. In addition to the power they generate, the Nanticoke units are also a major source of dynamic reactive power support for the part of the SWO transmission system between London and the GTA. Reactive power is necessary for maintaining adequate voltages across the transmission network to enable power transfers. Without this voltage support, large transfers across this network cannot occur because of the risk of transient and voltage instability. On the other hand, too much reactive power inserted onto the system can lead to over-voltages and risk of equipment damage.

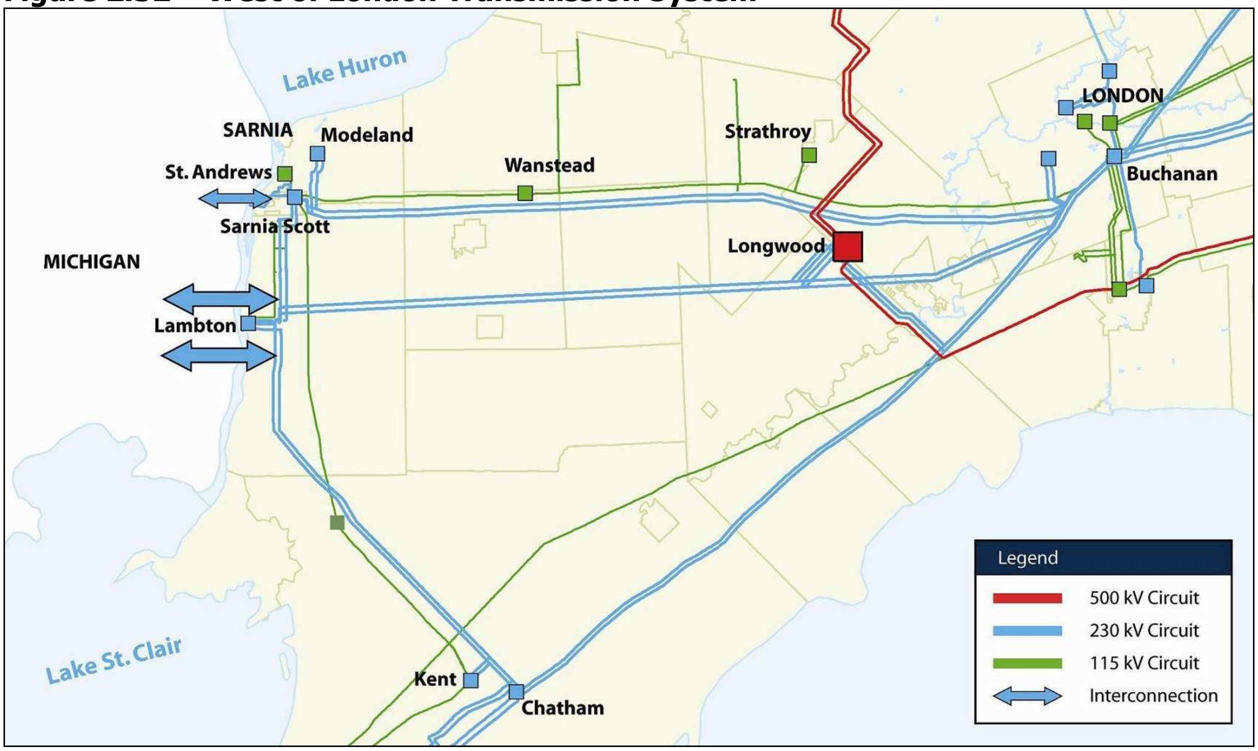
Since reactive power requirements vary considerably from hour to hour depending on operating conditions and transfer levels, automatic regulation of voltages and reactive supply is critical to the proper operation of power systems. Unlike static capacitor banks, which are installed to provide a fixed level of reactive power support, the reactive power output from the Nanticoke units is adjustable and can be deployed to regulate voltages in SWO.

With the planned shut-down of the coal-fired generation at Nanticoke, there is a need to provide both the quantities of replacement reactive power and the means to regulate voltages for the SWO transmission system. Two options for accomplishing this are currently being studied: one option is to operate four Nanticoke units as synchronous condensers. The other option is to provide an equivalent capacity using a mix of static Var compensators (SVCs) and fixed shunt capacitor banks. This study is still ongoing. Provisions for either option should be in place prior to the shut-down of the Nanticoke generating units.

Note that a new Bruce to GTA 500 kV line would alleviate some of the voltage support issues in SWO.

Transmission West of London – The system west of London is shown in Figure 2.32. This area of SWO has a number of prominent features: a large concentration of natural gas-fired generation in the Sarnia and Windsor areas, interconnection points with the state of Michigan at the Lambton station in Sarnia and the Keith station in Windsor, and large loads in the Sarnia and Windsor/Essex areas.

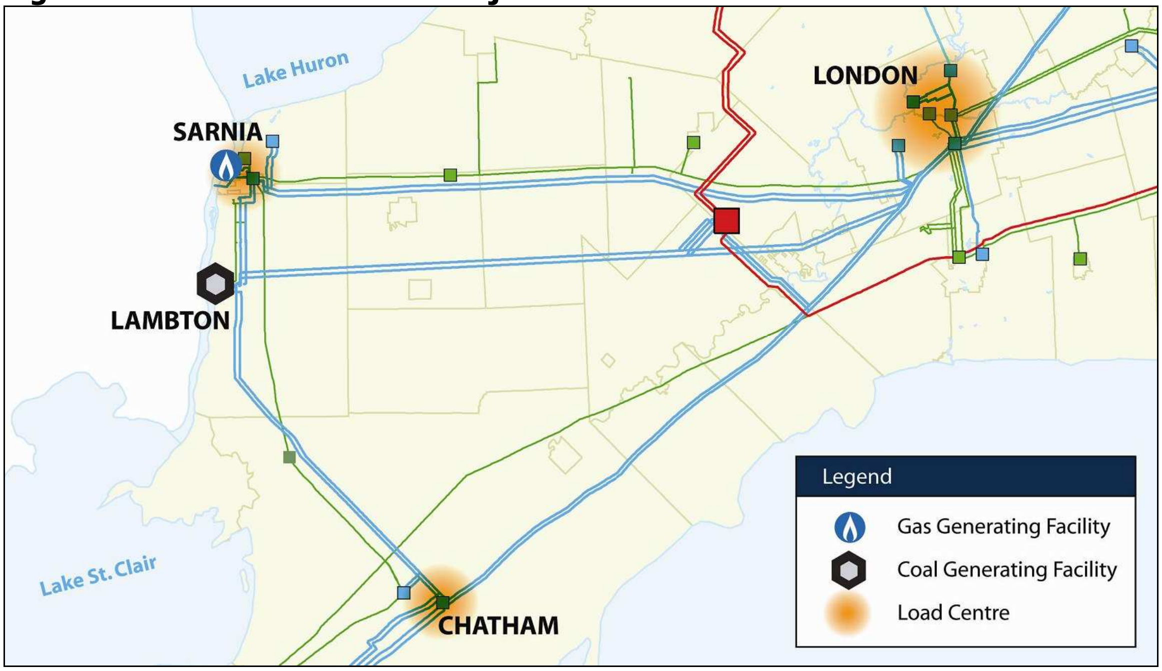
Figure 2.32 – West of London Transmission System



Source: Hydro One Networks Inc. and OPA

There is 2,000 MW of coal-fired generation in operation at the Lambton plant in Sarnia. With the planned shut-down of the coal-fired units in Ontario, including the Lambton plant, a number of gas-fired plants have been contracted to provide replacement power under the government's Clean Energy Supply procurement program. Two of these plants are located in the Sarnia area, namely the St. Clair Energy Centre (570 MW) and Greenfield Energy Centre (1,005 MW). The former has an in-service date of December 2008, the latter, October 2008. The Lambton station is being modified to alleviate short-circuit concerns and permit the operation of the new Sarnia generation in parallel with the existing units at Lambton. Besides Lambton and the two new generating plants, there are other existing gas-fired generating plants in the Sarnia area including TransAlta (510 MW). In total, and assuming the Lambton units remain in operation, there is over 4,100 MW of generating capacity in the Sarnia area. The major load centres and generation facilities are shown in Figure 2.33.

Figure 2.33 – West of London Major Load and Generation



Source: Hydro One Networks Inc. and OPA

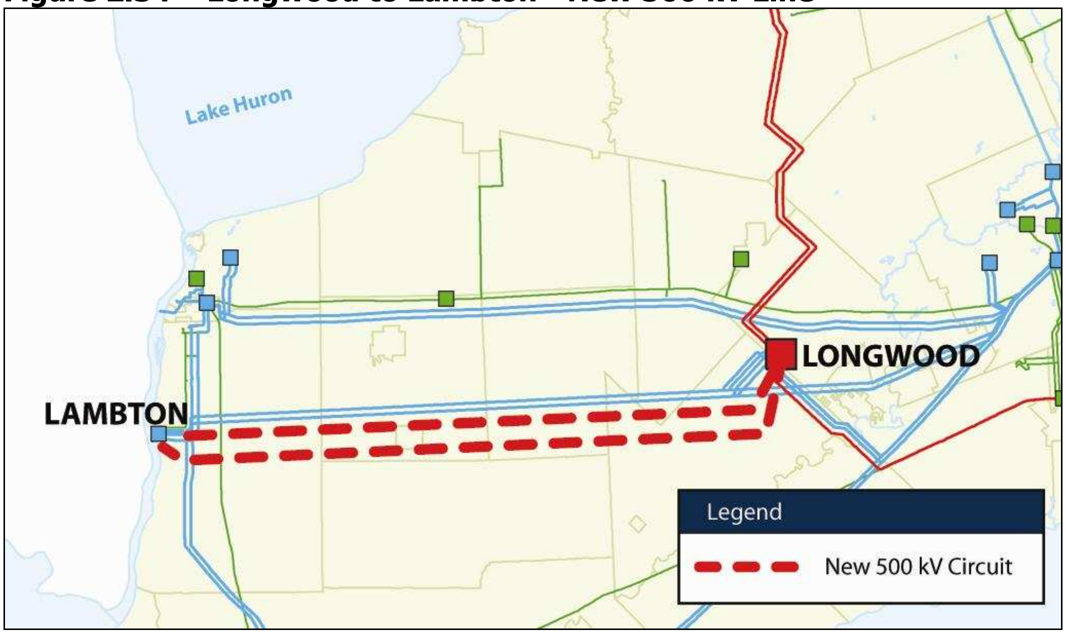
Furthermore, there are three high-capacity interconnections with the state of Michigan that terminate in the Sarnia area - two at the Lambton station with a capacity of 1,500 MW and one at the Scott station in the northern part of the Sarnia area, with a capacity of 410 MW. In total, the three interconnections can provide a simultaneous interconnection transfer capacity of about 1,250 MW (less than the sum of the individual capacities to accommodate contingencies with the interties).

The load in the Sarnia area is large, totalling about 800 MW. After netting the local demand in the Sarnia area, there is a potential for about 4,500 MW that could be transmitted from the Sarnia area to the London area.

As shown in Figure 2.32, there are six 230 kV circuits that connect the Sarnia area to the London area – two directly to the Buchanan station in London, two to the Longwood station west of London and two via Chatham to London. The capability of these transmission circuits for transferring power from the Sarnia area to the London area is about 3,000 MW. This is insufficient to permit the full transfer of about 4,500 MW of excessive generation and maximum import that can come from the Sarnia area. However, the eventual shutdown of the coal-fired units at Lambton will reduce this transfer requirement to about 2,500 MW. The transmission capability from Sarnia to London, therefore, is adequate for this resource development scenario for the Sarnia area.

Should additional major generation be added in the Sarnia area, the likely alternative for increasing the transfer capability between the Sarnia and London areas is the addition of a 500 kV line from the Longwood station to the Lambton station, a distance of about 80 km, as shown in Figure 2.34. The cost of this line and associated station facilities is in the order of $300 million.

Figure 2.34 – Longwood to Lambton - New 500 kV Line



Source: Hydro One Networks Inc. and OPA

The other part west of the London area is the Windsor/Chatham area. The transmission system supplying this system is shown in Figure 2.35. Chatham is supplied by two 230 kV circuits from Lambton and two 230 kV circuits from Longwood. From Chatham, four 230 kV circuits on two tower lines supply the Windsor area.

Figure 2.35 – Windsor/Chatham 230 kV Transmission System

Source: Hydro One Networks Inc. and OPA

The load in the Windsor/Essex area totals just over 1,000 MW. Local generation totals about 740 MW and includes Brighton Beach (580 MW), West Windsor (97 MW) and Windsor TransAlta (62 MW), all gas-fired plants. They are shown in Figure 2.36. There is another 84 MW to be added in east Windsor from the Combined Heat and Power Program. There is also an interconnection with the state of Michigan between Windsor and Detroit that has a capacity of about 400 MW.

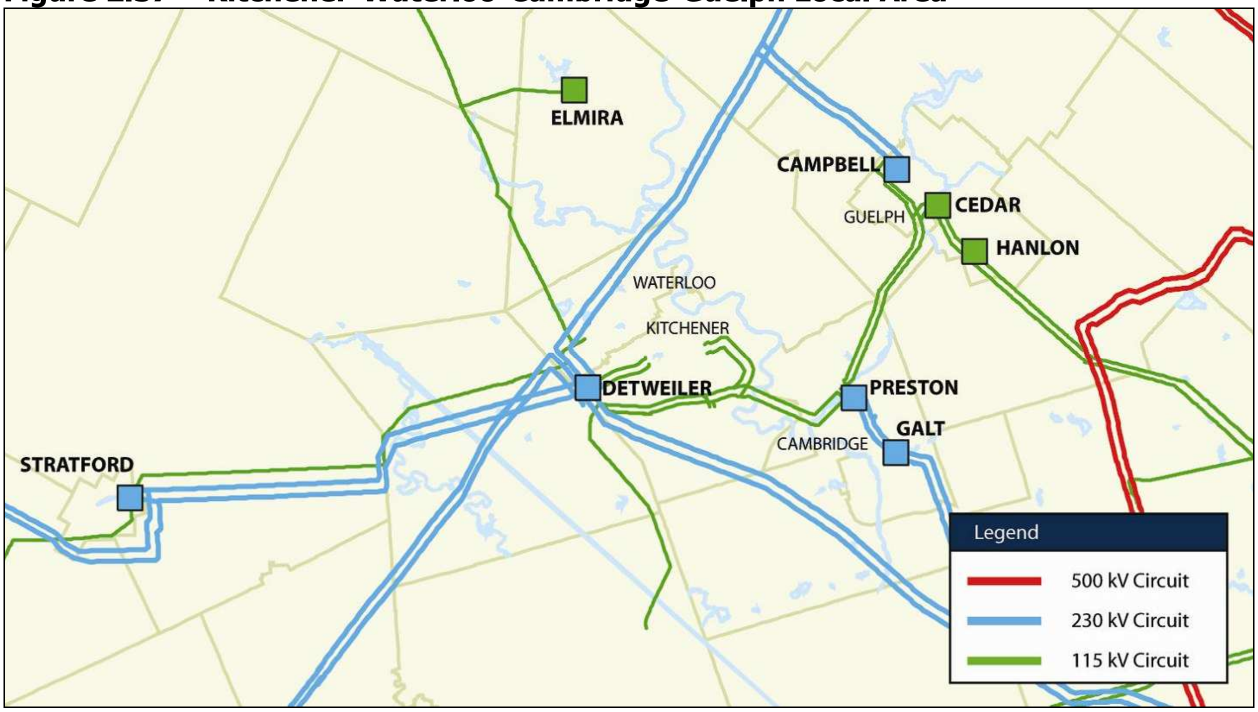
Figure 2.36 – Windsor/Chatham Major Load and Generation

Source: Hydro One Networks Inc. and OPA

Load and generation in this area is fairly well balanced, and the transmission between Chatham and Windsor is adequate for bulk system needs based on committed resources at this point in time. There are local transmission issues, which will be discussed in the following section on local area reliability in SWO, but the bulk transfer capability is generally not affected, with the exception of the need to keep the combined output of the Brighton Beach generating plant and the inflow from the Detroit interconnection within the capability of the 115 kV transmission system out of the Keith station in Windsor. The solution, which is to uprate the 115 kV system out of Keith station, is part of the overall Windsor/Essex local reliability reinforcement plan.

Local Area Supply Reliability – SWO is experiencing a robust growth in a number of its load centres including the Kitchener-Waterloo-Cambridge-Guelph (KWCG) area, the Brant-Woodstock area, and the Windsor/Essex area. In many of these cases, there is insufficient capacity to supply the increased load. Note that many of these growth centres are supplied from the 115 kV network, which has limited capability to expand. The details of the OPA's planning for these local area reliability needs is being addressed in a separate stakeholder engagement process focused at the affected communities. A summary of the specific local area reliability is included here. Because of the urgency, the Woodstock solution most likely will proceed ahead of the IPSP review. Other elements of the overall solution for the other projects may also proceed in this manner.

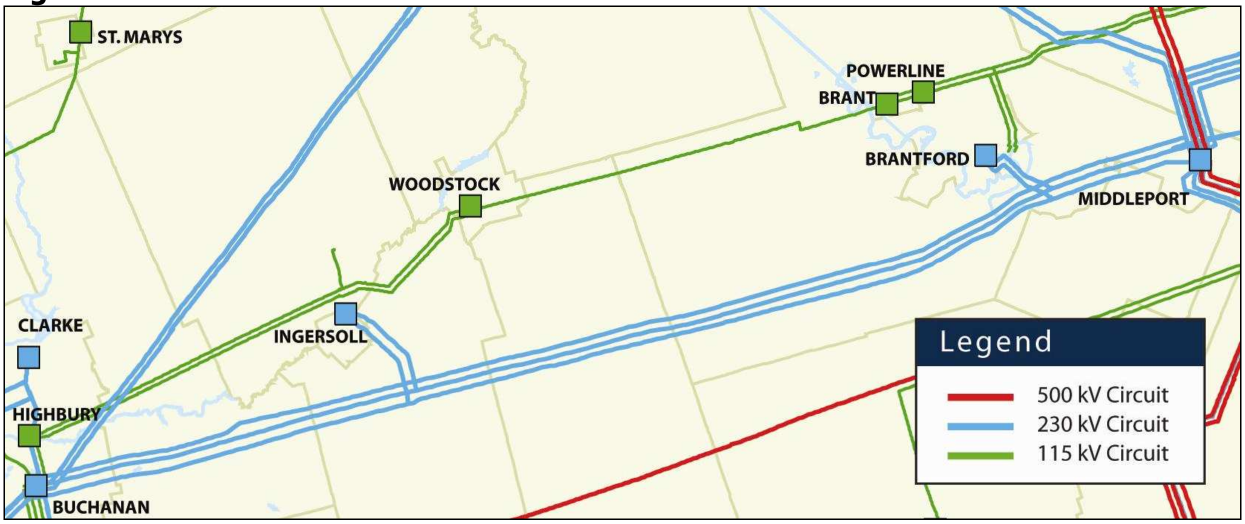
Figure 2.37 – Kitchener-Waterloo-Cambridge-Guelph Local Area



Source: Hydro One Networks Inc. and OPA

The KWCG area is shown in Figure 2.37. The 2005 peak load for the area totals over 1,300 MW. There are four distinct but inter-related supply adequacy needs: 115 kV supply to the Kitchener area load; 115 kV supply to the Guelph area load; 230 kV supply to the Cambridge and Kitchener load from the Middleport station. These needs must be addressed before 2008-2010. Interim measures such as the addition of capacitors and load transfers can extend the need date to 2012. Possible solutions to address these needs include adding local gas-fired generation in the Cambridge area; adding 230/115 kV transformation in Guelph to augment the 115 kV capacity there; and adding switching facilities on the 230 kV lines. Transmission alternatives to local generation at Cambridge are adding 500/230 kV transformation west of the Milton station and a 230 kV line from that station to the Cambridge area, or adding a 230 kV line from the Detweiler station in west Kitchener to Cambridge. The detailed studies and stakeholder engagement are currently underway.

Figure 2.38 – Woodstock-Brant Local Area



Source: Hydro One Networks Inc. and OPA.

The Woodstock-Brant area is shown in Figure 2.38. The Woodstock area, which has a load of about 100 MW, is experiencing rapid growth. The load in the Brant area, which is about 100 MW, is rapidly approaching the capacity of the 115 kV line serving that area. A solution will need to be in place in the 2008 to 2010 timeframe. The solution for Woodstock is a new 230 kV supply into the area from the south or from the west. The solution for Brant is augmenting the existing 115 kV supply. There is also the option of providing Brant with an augmented 115 kV supply from Woodstock once a 230 kV line is built into the area. The detailed studies and stakeholder engagement are currently underway.

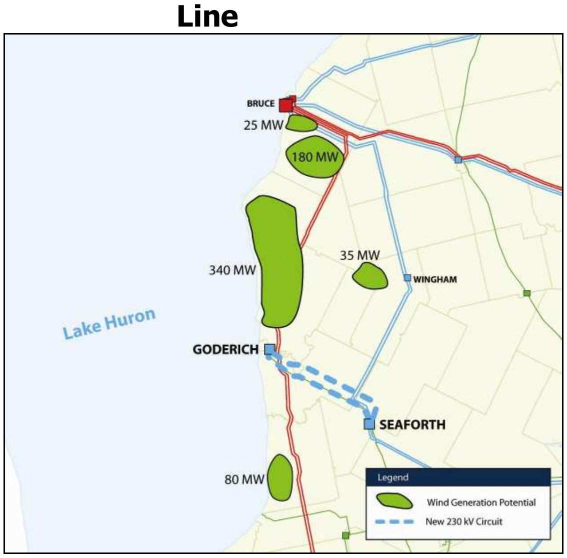
Figure 2.39 – Windsor-Essex Local Area

Source: Hydro One Networks Inc. and OPA

The Windsor/Essex area is shown in Figure 2.39. It is a major load centre with a load close to 1,000 MW. There is also local generation totalling about 740 MW. The growth in the City of Windsor is static, but the growth in the surrounding area is fairly robust. The issues for this area are inadequate capacity on the 115 kV system supplying Kingsville (Leamington area), Belle River and Tilbury; risk of major load interruptions from the loss of one of the transmission lines into the Lauzon station in Windsor; and congestion on the 115 kV system out of the Keith station that could restrict output of the Brighton Beach generating plant and inflow from the interconnection between Windsor and Detroit. Some of the potential solutions include a new 230/115 kV transformer station near Kingsville, uprating the 115 kV circuits out of the Keith station in Windsor, replacement of the 230/115 kV transformer at the Keith station and local generation in the Leamington area connected to the Kingsville station. The detailed studies and stakeholder engagement are currently underway.

Renewable Resource Development – Recent studies have identified excellent wind generation potential in Bruce/SWO - along the east shore of Lake Huron, the north shore of Lake Erie and the high land between Orangeville and Bruce. In many cases, the locations with good wind development potential in Bruce/SWO are reasonably close to existing 115 kV and 230 kV lines, which would facilitate their connection to the power grid. Two locations, however, that would require the building of enabler lines to facilitate their development, are the area on the Bruce Peninsula north of Owen Sound and the areas north and south of Goderich along the Lake Huron shore. The renewable resource potential and enabler lines are shown in Figure 2.40 and Figure 2.41.

Figure 2.40 – East Lake Huron Renewables and Enabler Line



Source: Hydro One Networks Inc. and OPA

Figure 2.41 – Bruce Peninsula Enabler Line

The wind potential on the Bruce Peninsula is estimated to total about 400 MW, as shown in Figure 2.41. Currently, there is no high-voltage transmission line on the Bruce Peninsula. To develop this wind resource, a single-circuit 230 kV line would be required from the Owen Sound station to just south of Tobermory. The distance is about 80 km and the cost of this enabler line is about $90 million. A lead time of about five years would be required.

Similarly, the Lake Huron shore has a wind generation potential of about 600 MW, located north and south of Goderich. Currently, the main transmission through this area is the 500 kV line between Bruce and Longwood. Connection of wind generators to the 500 kV circuits is not preferred, both because of their reliability impact on the bulk facilities and the high cost of the 500 kV connection equipment required. A possible solution in providing a 230 kV connection point for these generators would be to rebuild the 35 km Goderich to Seaforth 115 kV line to enable it to operate at 230 kV, and convert the Goderich station for 230 kV operation. This would allow the wind generators located just north and south of Goderich to be connected to this station or tapped to the line supplying the station. The estimated cost of this work is $60 million. A lead time of about three to five years is required. The enabler line for Goderich is shown in Figure 2.40.

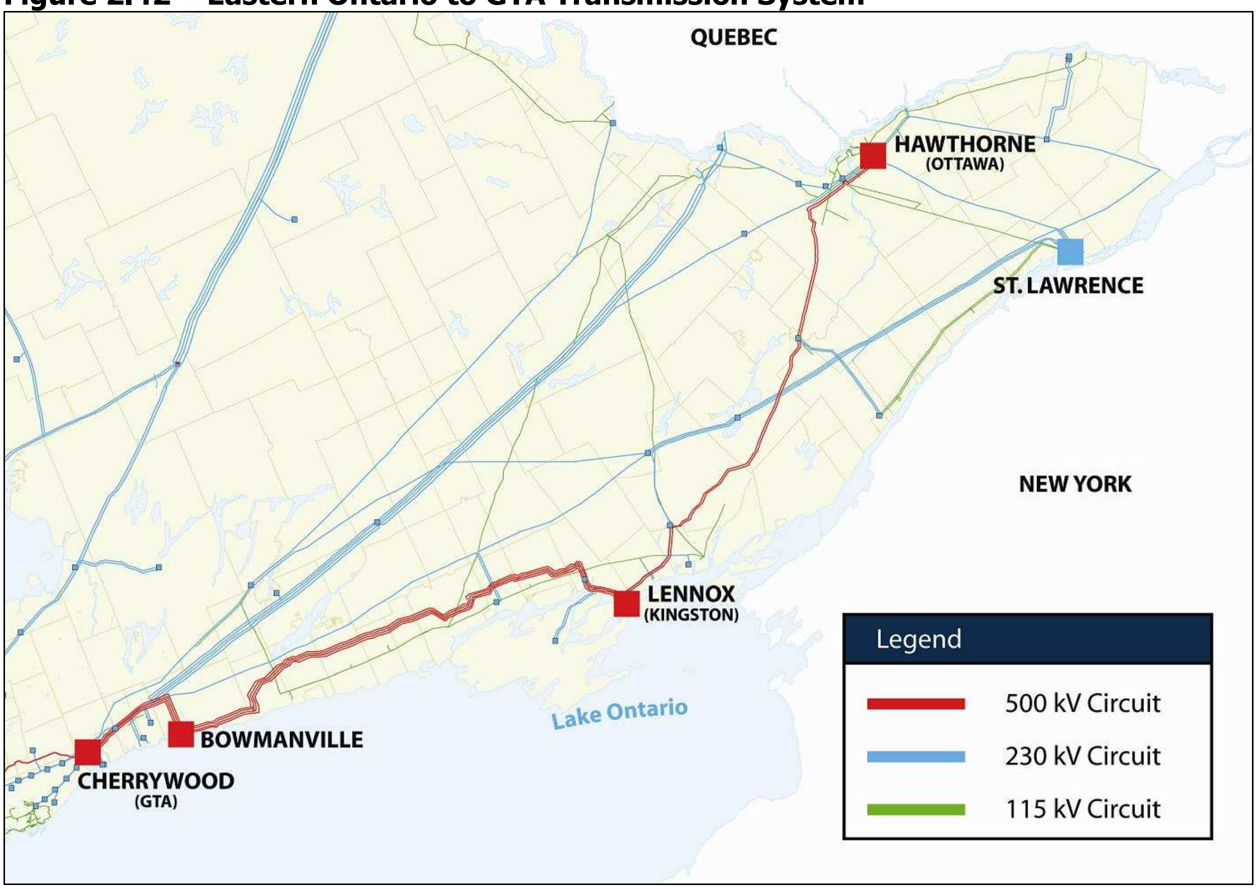
In summary, for the Bruce/SWO subsystem, a new 500 kV transmission line from Bruce to the GTA is required as soon as possible. The total generation in the Bruce area following the addition of two more Bruce units and 725 MW of committed wind generation will exceed the transmission capability out of Bruce. Furthermore, there is a potential for another 1,000 MW of wind generation in the area. There are two options for routing the new line - from Bruce to Milton or from Bruce to Essa along existing transmission right-of-ways. The Milton option is better technically. In the meantime, there are a number of near-term and interim measures possible for minimizing congestion costs until the new line is in-service. These include generation rejection, series compensation, 230 kV line uprating, the addition of shunt compensation in Bruce/SWO, and restricting further generation development in the Bruce area. These solutions will likely proceed prior to and independently from the IPSP approval. Adequate reactive power support in SWO is also critical - either from Nanticoke generating units or from capacity on SVCs. There are also a number of local reliability needs in SWO, because of robust growth. Integrated solutions are being considered in these cases.

2.3.7 Eastern Ontario to the GTA

Overview

The bulk transmission system from eastern Ontario to the GTA is shown in Figure 2.42. The key elements of this transmission system include two 500 kV circuits from the Hawthorne station in the Ottawa Area to the Lennox station in the Kingston area and four 500 kV circuits from the Lennox to Bowmanville stations. Bowmanville also connects four 500kV circuits to Cherrywood in the GTA and the Darlington nuclear generating station in Clarington. From an electrical perspective, the Bowmanville station is the boundary point for the bulk transmission system between eastern Ontario and the GTA. The supply to the GTA from eastern Ontario generation and imports from Quebec and New York primarily flows along the 500 kV system towards Bowmanville. This flow combined with the generation output from Darlington forms the main power injection into the GTA from the east. Under high import conditions during summer peak periods, the transfer levels from Bowmanville to Cherrywood can range from 4,500 MW to 5,000 MW.

Figure 2.42 – Eastern Ontario to GTA Transmission System



Source: Hydro One Networks Inc. and OPA

The 230 kV network in eastern Ontario primarily connects generation sources, provides local supply to the various load centres and delivers imports from Quebec and New York. This network is generally not used for large power transfers to southwest Ontario. While there are six 230 kV circuits that connect Cherrywood to stations in the Peterborough, Belleville and Ottawa areas, they are long circuits; several of these circuits are 250 to 300 km in length. As a result they collectively transfer only a small amount of power from eastern Ontario to the GTA. During summer peak periods, transfer levels to the GTA are in the 300 MW range.

Generation Resources

There is a diversity of generation sources in eastern Ontario. There are significant hydroelectric generation facilities along the St. Lawrence, Ottawa and Madawaska rivers. The Saunders plant at St. Lawrence is the largest hydroelectric facility providing 980 MW of generation. The Chenaux and Chat Falls plants along the Ottawa River provide respectively 135 MW and 95 MW. The five plants (Mountain Chute, Barrett Chute, Calabogie, Stewartville and Arnprior) along the Madawaska River provide a potential capacity of 600 MW. The Madawaska plants provide primarily peaking generation, while the Saunders and, to a lesser degree, the Ottawa river plants provide baseload generation for eastern Ontario.

Figure 2.43 – Eastern Ontario Generation

Source: Hydro One Networks Inc. and OPA

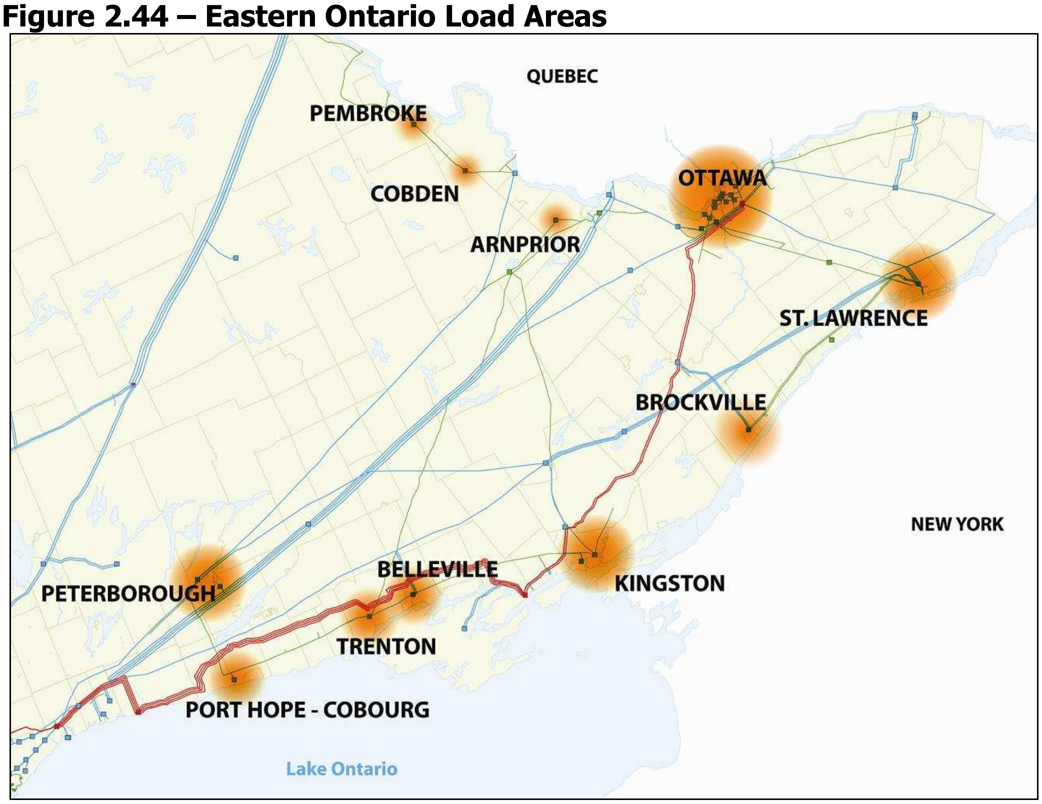
The 2,000 MW Lennox generating station in Kingston is the major gas facility in eastern Ontario. There are three gas non-utility generator (NUG) facilities, the 150 MW AES Cogeneration plant and the 200 MW Cardinal Power plant east of Brockville, and the 70 MW Ottawa Health Science Centre in Ottawa. The Wolfe Island Wind Farm project was one of the Renewable Energy Supply II RFP winners and is presently under development south of Kingston. The Wolfe Island project will provide 200 MW of wind capacity by the end of 2008

Most of the generation sources in Eastern Ontario are connected on the 230 kV system with a few exceptions. Two of the four Lennox units are connected directly to the 500 kV system. The Barrett Chute and Stewartville hydroelectric plants are connected on the 115 kV system in the Arnprior area. The Cardinal Power and Ottawa Health Science Centre plants are also connected on the 115 kV system.

Area Loads

Eastern Ontario is a winter peaking region. While the overall Ottawa area remains winter peaking, the City of Ottawa has more recently become summer peaking. The winter peak load is about 3,800 MW and the summer peak load is about 3,500 MW. The major load centres are found in the Ottawa, Kingston, Peterborough, Belleville-Trenton, Port Hope-Cobourg, Arnprior, Cobden-Pembrooke and St. Lawrence-Brockville areas.

Figure 2.44 – Eastern Ontario Load Areas



Source: Hydro One Networks Inc. and OPA

Growth in eastern Ontario is expected to be less than 1.2 percent over the next 20 years. Table 2.5 shows the 2005 winter and summer peak loads of the major load areas in eastern Ontario. Because of the geographic diversity of the areas, the peak loads in each area may not coincide with the overall Ontario system peak. Table 2.5 shows the historical non-coincident peak load for each area.

Table 2.5 – Eastern Ontario Non-Coincident Peak Loads

Area	Winter Peak	Summer Peak
Ottawa	1,810	1,790
Kingston	690	550
Peterborough	330	250
Belleville-Trenton	270	240
St. Lawrence-Brockville	210	160
Port Hope-Cobourg	160	120
Cobden-Pembroke	100	80
Arnprior	90	70
Other	230	170
Total	3,890	3,430

Source: IESO

Interconnections

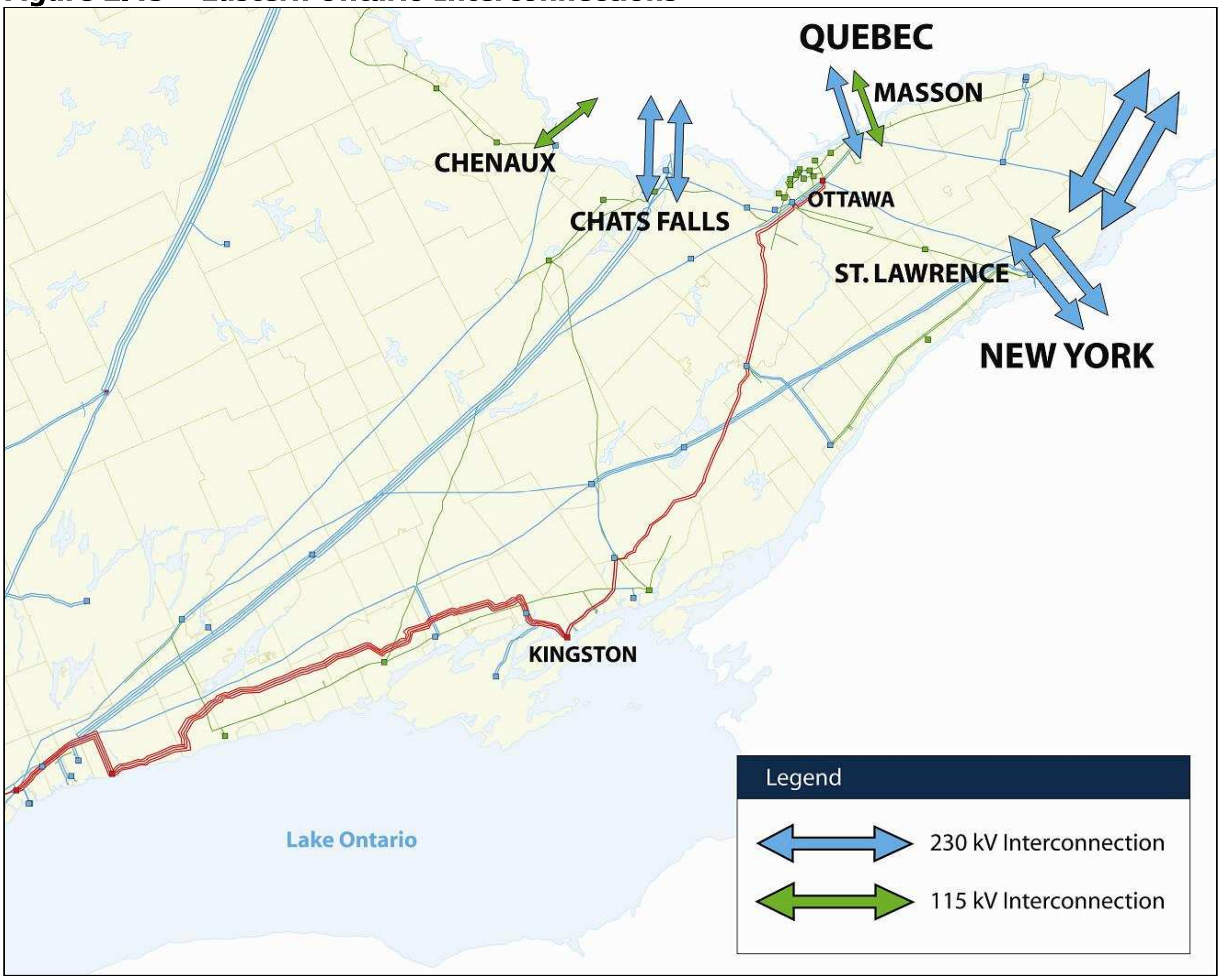
There are a number of interconnections with Quebec and New York that permit access to additional generation sources for local and provincial resource needs. There are two 230 kV interconnections with New York at the St. Lawrence station in Cornwall. These interconnections have both voltage regulators and phase angle regulators installed to control the voltage and the power flows between Ontario and New York. However, the ability of these phase angle regulators to control power flows is limited. Together these interconnections have a bi-directional transfer capability of 400 MW.

Unlike many of the interconnections with the U.S., the interconnections with Quebec are operated in a “non-parallel” manner. When power is imported from Quebec, generators in Quebec are disconnected from the Hydro-Quebec system before they are connected to the Ontario system. The reverse is true when power is exported to Quebec. Ontario generators are disconnected from Ontario before connecting to Quebec. There is no parallel or “simultaneous” connection to both the Ontario and Quebec systems. The generators are “radial” to one system at any time.

In total, there are seven interconnections with Quebec in eastern Ontario. There is a 115 kV interconnection with a transfer capability of 65 MW in the Cobden-Pembroke area near the Chenaux generating station. There are two 230 kV interconnections with a combined transfer capability of 440 MW at the Chat Falls generation station. East of Ottawa between the Cumberland area in Ontario and the Masson area in Quebec, there are a 230 kV and a 115 kV interconnection with transfer capabilities of 250 MW and 90 MW respectively; however, the 115 kV interconnection is reserved for emergency use only. East of Cornwall, there are two 230 kV interconnections with Quebec that have a combined transfer capability of 800 MW.

When importing from Quebec on the Cornwall interconnections, the normal mode of transfer is 400 MW on one interconnection towards Ottawa and 400 MW on the other interconnection towards St. Lawrence. The interconnection capabilities specified refer to the summer transfer capability for flows into Ontario from Quebec. The capabilities of several interconnections are significantly lower for flows out of Ontario and into Quebec. Collectively the flow capability into Ontario is about 1,550 MW, and out of Ontario into Quebec the flow capability is less than 600 MW.

Figure 2.45 – Eastern Ontario Interconnections



Source: Hydro One Networks Inc. and OPA

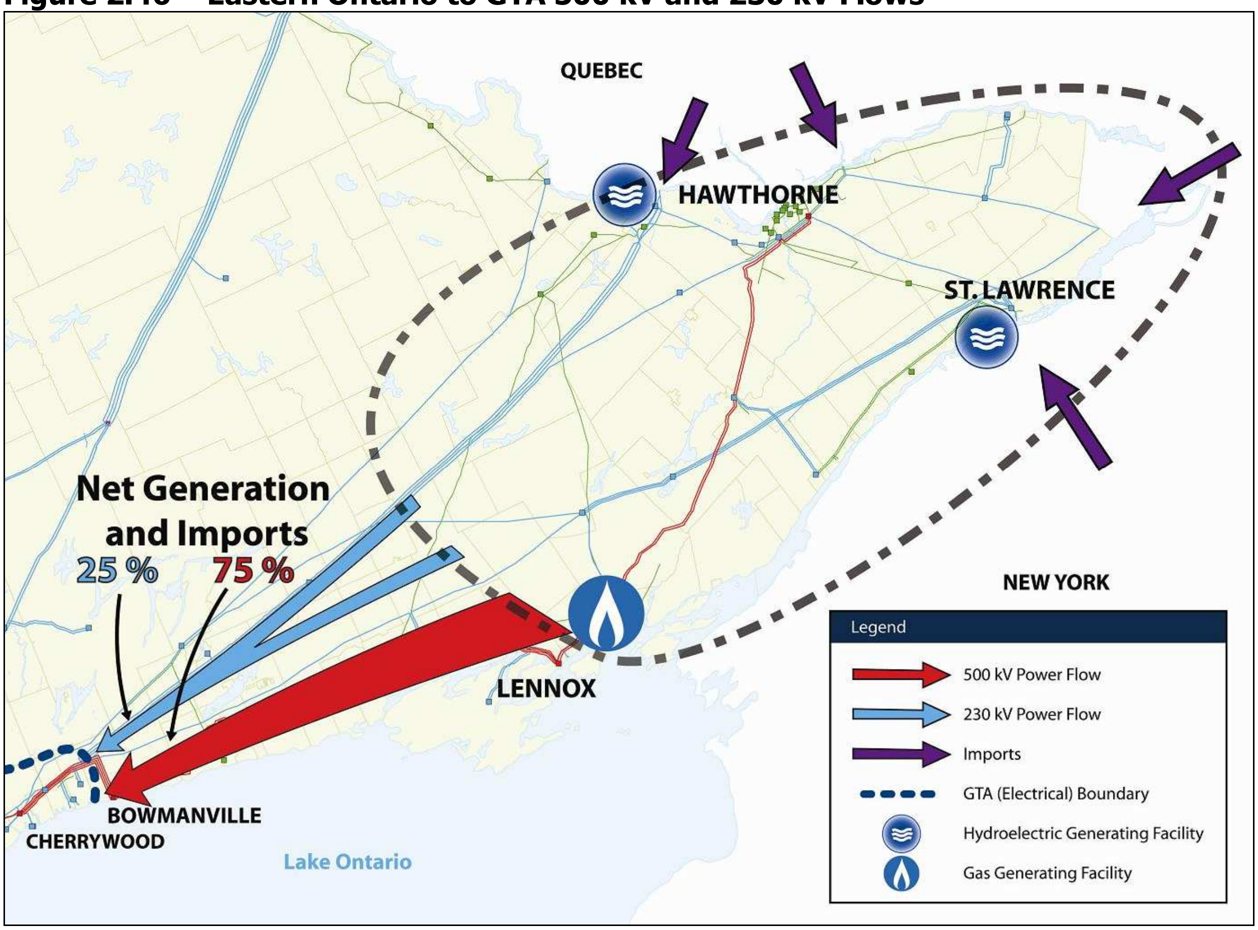
Transmission Issues and Options

While there are 4,500 MW of installed generation capacity in eastern Ontario, the actual available capacity is lower during summer peak conditions and is subject to a number of factors including outages, contractual arrangements with non utility generators (NUGs), water levels for hydroelectric plants and wind conditions for wind farms. With a total area load of

3,500 MW, eastern Ontario is generally self-sufficient with small generation surpluses during peak periods.

As mentioned earlier, surplus generation and imports will flow towards the GTA primarily on the 500 kV system and to a lesser degree on the 230 kV system. Approximately 75 percent of the net generation and imports from the Cornwall and Ottawa areas will flow on the Lennox to Bowmanville 500 kV circuits to the GTA and 25 percent will flow on the six 230 kV circuits into Cherrywood. The Lennox to Bowmanville circuits have a transfer capability of about 4,500 MW, which can accommodate the full range of generation and imports in eastern Ontario. During summer periods with high import levels, flows on these circuits have typically ranged from 1,000-1,400 MW. From the eastern Ontario 500 kV system perspective, there is significant room to incorporate new generation sources and further interconnection expansion. There may be facilities in the GTA that could be more limiting for new generation and imports. This is discussed further in the GTA East subsection under GTA Transmission Options.

Figure 2.46 – Eastern Ontario to GTA 500 kV and 230 kV Flows



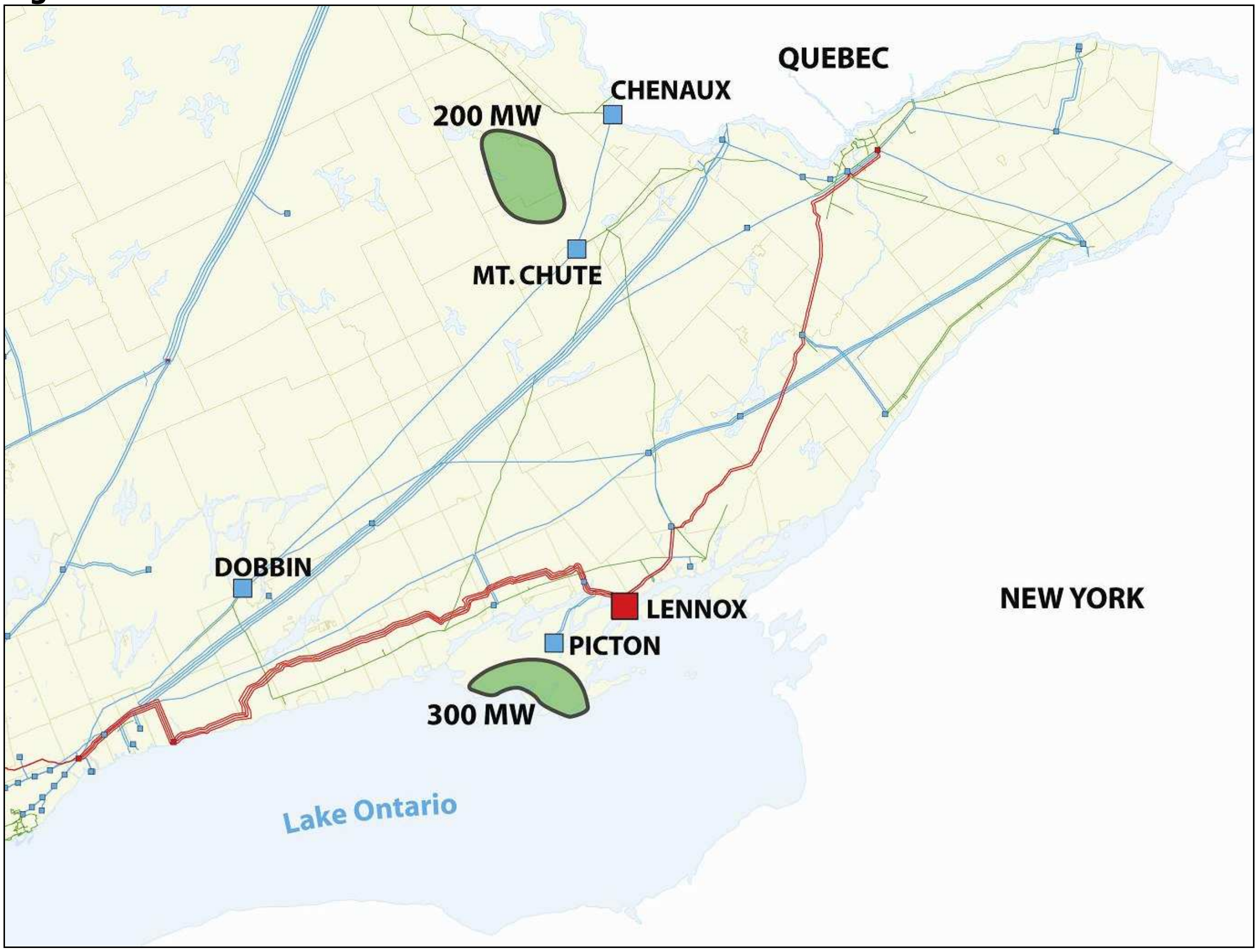
Source: Hydro One Networks Inc. and OPA

On the 230 kV system there are significantly more limitations for incorporating new generation sources. With the exception of two 230 kV corridors, many of the 230 kV circuits are typically long, isolated and span a broad geographic area. The two main 230 kV corridors are the circuits from Chat Falls to Peterborough and the GTA, and the circuits from St. Lawrence to Hinchinbrooke to Lennox in Kingston. The path from Chat Falls to Peterborough is over 200 km long and the path to the GTA is about 270 km. The path from St. Lawrence to Lennox is 210 km. Even on these corridors, the total capacity is limited and a significant portion is used to deliver the existing resources to local areas or towards the GTA. For example, with all the Saunders generating units running and high imports from Quebec and New York, there is no spare capacity on the St. Lawrence to Hinchinbrooke corridor. There is capacity to accommodate as much as 300 MW on the 230 kV system near Lennox, including the Hinchinbrooke to Lennox circuits. Incorporating more generation in the Kingston area may require new connection lines into the Lennox station and new 500/230 kV transformers at the station to send the surplus power to the 500kV system. The 230 kV circuits in the other areas of eastern Ontario will have more limitations and, depending on the connection location, the ability to connect new generation facilities can vary from 50-200 MW. Unless the new generation is near the 500 kV connection points at Lennox or Hawthorne, additional 230 kV transmission may be required for larger facilities.

With respect to renewable development, there are two areas in eastern Ontario identified with good wind potential. One area is approximately 50 km southwest of the Chenaux station and the other area is in Prince Edward County near the Picton station. At the Chenaux location three sites with a combined wind potential of 200 MW have been identified. The only 230 kV transmission in the vicinity is the single circuit which connects the Chenaux and Mountain Chute generating stations to the Dobbin station in Peterborough. With Chenaux and Mountain Chute running during summer peak periods, there is less than 50 MW of capacity on this circuit and congestion will occur depending on the level of generation development. The risk of congestion is lower during off-peak periods, when Mountain Chute is not running, since it is a peaking facility and Chenaux output may be lower. There may be as much as 150 MW of capacity available during such periods. In addition to the connection line, to connect the wind facility to the 230 kV line, the Chenaux to Dobbin line capacity will require upgrading to incorporate the full wind potential in this area.

At the Picton location, two sites with a combined wind potential of 300 MW have been identified. There is adequate capacity on the 230 kV circuits from the Picton station to Lennox to incorporate this potential. Only additional transmission connection facilities to the generation sites are required. From an electrical perspective, generation connected to the 230 kV circuits in this area is effectively a direct connection into Lennox. As mentioned above, generation development beyond 300 MW in this area will require additional 500/230 kV transformers at Lennox.

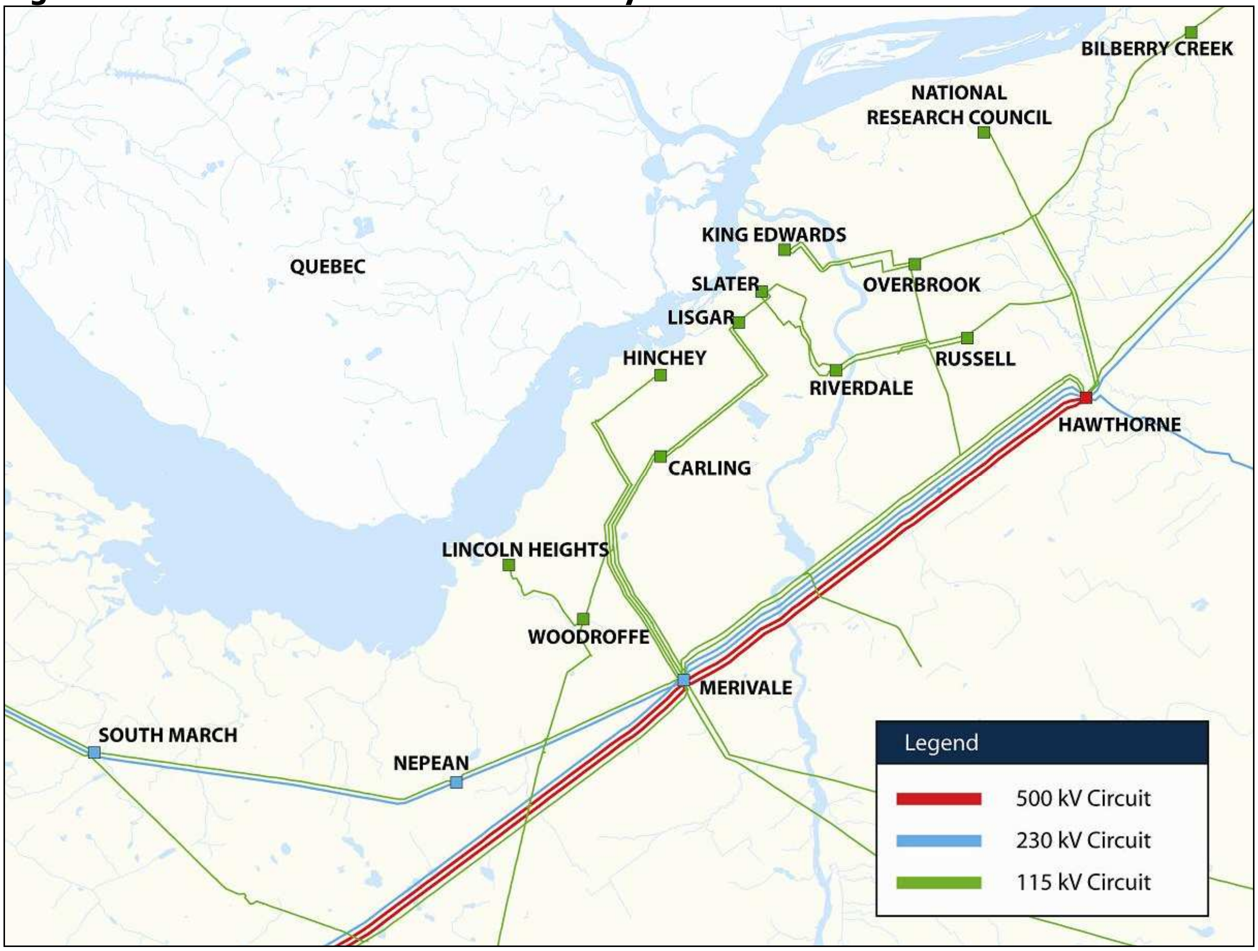
Figure 2.47 – Eastern Ontario Wind Generation Potential



Source: Hydro One Networks Inc. and OPA

The bulk transmission system into the Ottawa area consists of two 500 kV circuits from Lennox and four 230 kV circuits from the St. Lawrence, Chat Falls, St. Isidore and Cherrywood stations. The transfer capability of this set of facilities is 1,900 MW and is constrained by area voltage issues when one of the 500 kV circuits is unavailable. The 500 kV circuits and the reactive power from the Lennox generating station provide critical voltage support and permit the high transfer levels into the Ottawa area. Without this voltage control from Lennox, transfer capability into the Ottawa area may not be sufficient to supply the demand during extreme weather or following transmission contingencies. The Ottawa area summer load is about 1,800 MW and the expected load growth is approximately 1.2 percent annually over the next 10 years. Additional transmission facilities may be required for both voltage support and supply capacity to meet the area load beyond the medium term or earlier, should growth exceed projections.

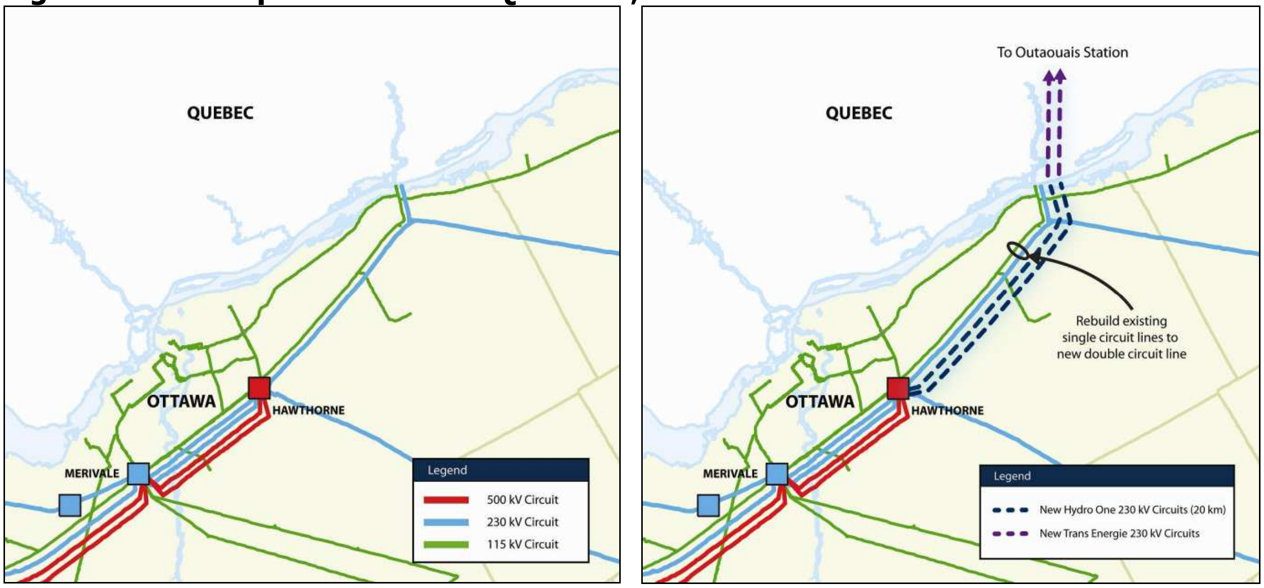
Figure 2.48 – Ottawa Area Transmission System



Source: Hydro One Networks Inc. and OPA

Hydro One Networks and TransEnergie, the Quebec transmission company, are jointly working on a plan to construct a new 1,250 MW interconnection. The interconnection crossing will be at the same location as the existing 230 kV interconnection to the Masson area in Quebec. On the Ontario side, Hydro One Networks will build a new 230 kV double-circuit line, 20 km long, on an existing corridor presently occupied by a single-circuit 115 kV and a single-circuit 230 kV tower line. Hydro One Networks will rebuild these single-circuit lines to two double-circuit tower lines. One tower line will carry the two new 230 kV circuits to Quebec and the other tower line will carry the existing 115 kV and 230 kV circuits. Station upgrades at the Hawthorne station are also planned to connect these two new circuits and provide reactive power support for the higher transfers expected at the station. Some additional upgrades to the 230 kV system downstream of Hawthorne may be required to accommodate the higher transfers under some generation, loading and import conditions. This may include increasing the capacity of the short line section between the Hawthorne and Merivale station and modifications of some special protection schemes. Hydro One Networks is presently reviewing whether any additional requirements are necessary. There is adequate room on the 500 kV system to accommodate 1,250 MW of additional imports.

Figure 2.49 – Proposed Ontario - Quebec 1,250 MW Interconnection



Source: Hydro One Networks Inc. and OPA

The unique feature of this new interconnection is that the Ontario and Quebec systems will be electrically connected by HVDC converter facilities at the Outaouais station in Quebec. This means that AC power from the sending side is converted to DC power before being transmitted. The power is reconverted to AC before being injected into the receiving side's transmission system. Quebec has a number of HVDC interconnections with New York, New England and New Brunswick. The main advantage of a HVDC connection is that it provides rapid and full control of the amount of power that can flow. Large changes in the power flow levels can be made within a fraction of a second. This feature can be used to relieve overloaded lines and equipment when there is a sudden loss of a key transmission element.

This new 1,250 MW interconnection will provide greater access to resources in Quebec. It will address not only long-term bulk transmission needs for the Ottawa area, but also near-term local supply issues. The 115 kV circuit, which supplies a number of customers in east Ottawa and the municipalities of Cumberland, Rockland and Hawkesbury, is currently at capacity. Currently, operating measures are deployed to mitigate overloads during peak periods. The new interconnection project involves rebuilding this 115 kV tower line and, in the process, upgrade the capability of the 115 kV line. The station upgrades at Hawthorne will provide additional reactive support to the local area and reduce dependence on the Lennox generation for voltage support during peak periods.

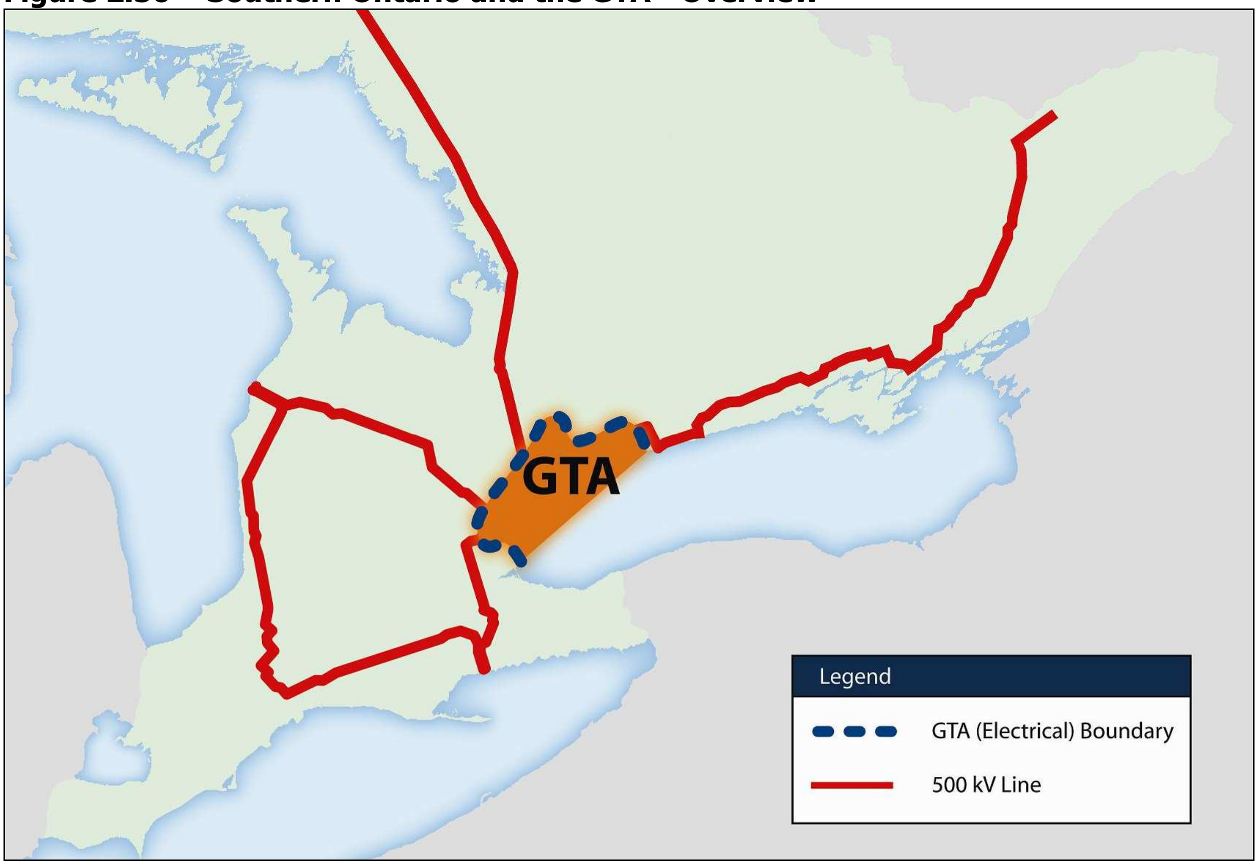
A new 1,250 MW interconnection will slightly increase the flows on the St. Lawrence to Hinchinbrooke 230 kV circuits. Under some conditions, these circuits have experienced congestion in the past and require the use of a generation rejection scheme. If congestion levels continue to increase, expansion of the generation rejection scheme or upgrades to the 230kV circuits may be required. Another consideration for managing congestion on this path is to improve the power flow control capability on one of the phase angle regulators (PARs) on the interconnections with New York at the St. Lawrence. Currently, one of the PARs has only half the flow control capability of the other unit. When the PARs reach their capacity, the scheduled flow on the interconnections cannot be maintained and this could add to congestion on the 230 kV system in the St. Lawrence area.

Other potential developments in eastern Ontario involve new connections to the Cornwall area. Canadian Niagara Power Inc., a subsidiary of FortisOntario Inc. and a licensed transmitter and distributor, is currently exploring with Hydro One Networks Inc. the feasibility of new interconnections in the Niagara and Cornwall regions. In Niagara, the project involves a synchronous connection between the IESO-controlled grid and the grid controlled by the New York Independent System Operator. In Cornwall, the project involves a synchronous connection between the IESO-controlled grid and Hydro-Quebec through the Cedar Rapids Transmission system. The benefits of these incremental projects may include greater intertie capabilities between neighbouring systems, security of supply to the immediate area and competitive market influence improving price stabilization in Ontario.

2.3.8 The Bulk Transmission System in the GTA

The 500 kV bulk transmission supply to the GTA area is shown in Figure 2.50. The 500 kV system delivers large amounts of power from major generation sources. Some of these generation facilities are located far from the GTA. These include the Bruce nuclear generating station on the shores of Lake Huron, the hydroelectric facilities in northern Ontario and generation facilities in the Kingston and Cornwall areas in eastern Ontario. The 500 kV system also connects the Darlington nuclear generating facility just east of the GTA.

Figure 2.50 – Southern Ontario and the GTA - Overview



Source: IESO and OPA

The GTA Transmission System

The GTA transmission system supplies over 40 percent of the total provincial load and represents the largest subsystem in Ontario. The GTA's summer peak load of 10,500 MW in 2005 is greater than the load in most provinces of Canada (except Quebec) and is similar to the provincial loads of B.C. or Alberta. In order to reliably supply a system the size of the GTA, both significant transmission and local generation facilities are needed.

Figure 2.51 shows the GTA transmission system. The geographical area supplied by the GTA transmission system includes the City of Toronto and large portions of the regional municipalities of Halton, Peel, York and Durham. The GTA outline shown is based on electrical considerations, not the municipal boundaries that form the GTA. In essence, the electrical boundary for the area supplied by the GTA transmission system is the continuous urban and suburban area, and not the outer rural portions of the GTA's municipal boundaries.

Figure 2.51 – GTA Transmission System

Source: IESO and OPA

The bulk transmission system that brings power to the GTA comprises 500 kV and 230 kV lines. Most of the power transmitted to the GTA is delivered on the 500 kV system. Figure 2.52 shows the 500 kV power flows coming into the GTA and the five stations in the GTA connected to the 500 kV system. Four are transformer stations that step the power down to the 230 kV level with the use of 500/230 kV transformers. The transformer stations include: Cherrywood in Pickering, Parkway in Markham, Claireville in Vaughan and Trafalgar in Milton. The fifth station, located in Milton, does not have 500/230 kV transformers, but contains facilities for connecting and switching a number of 500 kV lines from the south and west into the GTA.

Figure 2.52 – GTA 500 kV Supply

Source: IESO and OPA

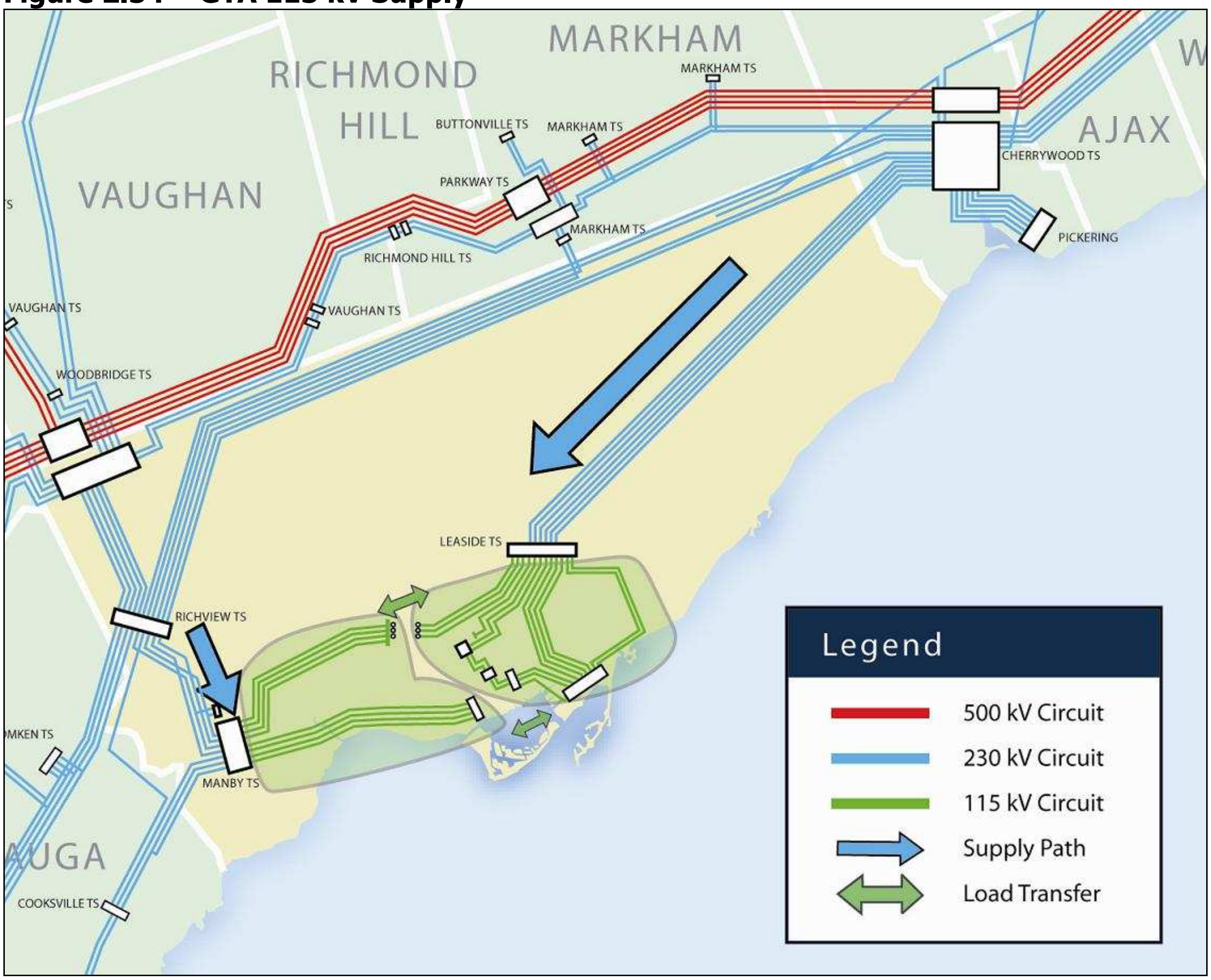
The 230 kV system connecting the GTA to outside areas delivers only a limited amount of power into the GTA. As shown in Figure 2.53, there are three 230 kV supply paths into the GTA. The 230 kV circuits running north from Claireville to Minden and those running east from the Cherrywood station to Peterborough, Belleville and Ottawa are primarily supply circuits for loads in the York and Durham regions. Since these are long circuits, their ability to bring power into the GTA is very limited. The four 230 kV circuits on the Burlington to Trafalgar corridor provide the only significant transfer capability into the GTA 230 kV system. A large portion of the generation and imports from Niagara and other southwest areas can flow along this 230 kV corridor.

Figure 2.53 – GTA 230 kV Supply

Source: IESO and OPA

Within the GTA, power is delivered to the loads largely via the 230 kV transmission network. Only in the pre-amalgamation portion of the city is the power further stepped down from 230 kV to 115 kV. There are two 230 kV to 115 kV transformer stations: Leaside station located in East York and Manby station located in south Etobicoke. The 115 kV subsystems supplied out of Leaside and Manby are operated separately and are not simultaneously connected together at the 115 kV level. Some switching facilities allow some load to be transferred back and forth between the two subsystems, but only in a limited fashion. The 115 kV supply systems are shown in Figure 2.54.

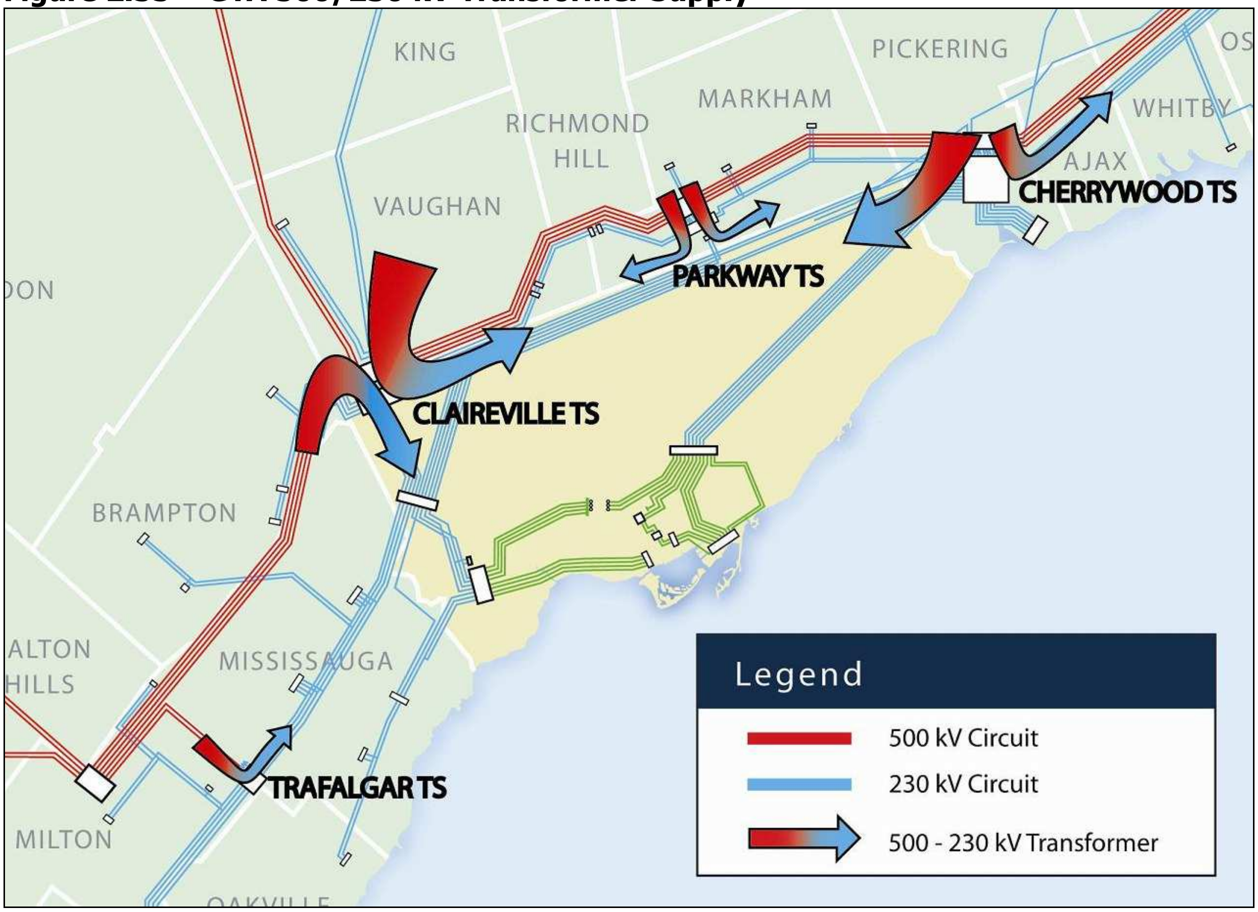
Figure 2.54 – GTA 115 kV Supply



Source: IESO and OPA

The major gateway from the 500 kV system to the GTA 230 kV system is via 12 large (750 MVA) 500/230 kV transformers. There are four at the Cherrywood station, two at the Parkway station, four at the Claireville station and two at the Trafalgar station. Collectively they deliver approximately two-thirds of the power to the GTA 230 kV system. The four major transformer stations and the 500 to 230 kV transformation are illustrated in Figure 2.55.

Figure 2.55 – GTA 500/230 kV Transformer Supply

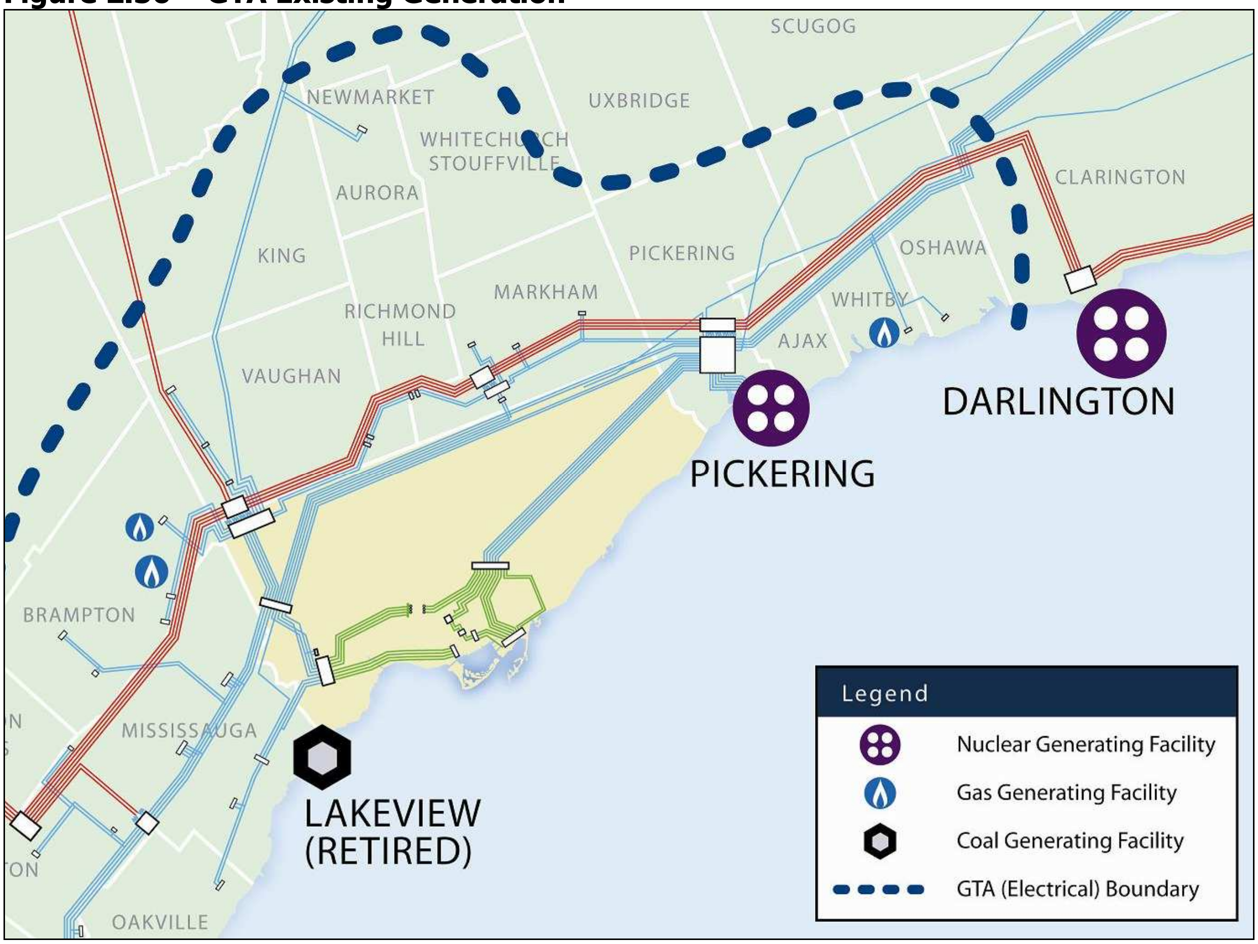


Source: IESO and OPA

In addition to the transmission supply, the generation sources within the GTA are also critical to supply the GTA load. With the shutdown of the coal-fired Lakeview Generating Station (GS) in April 2005, there is only one major local generation source found inside the GTA. This is Pickering GS, where there is 3,000 MW of generation capacity. A collection of smaller generators connected at distribution voltage levels (i.e., below 50 kV) makes up another 300 MW of capacity.

Although Darlington GS, with 3,600 MW of generation, is located near the GTA, its power is delivered on the 500 kV lines from the Bowmanville station. It needs to go through the GTA 500/230 kV transformers and hence, is not considered an internal generation source.

Figure 2.56 – GTA Existing Generation

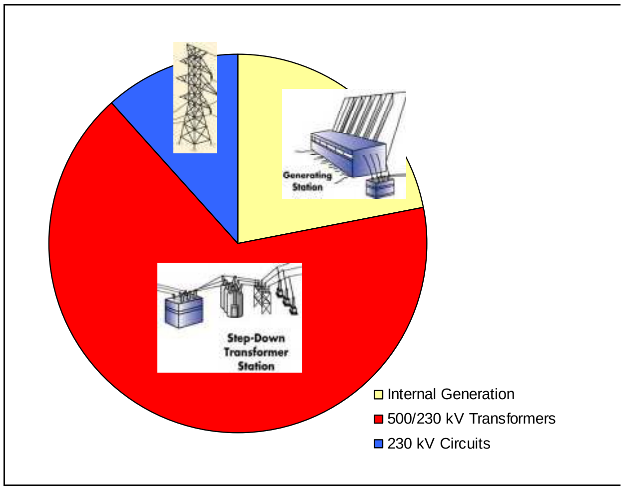


Source: IESO and OPA

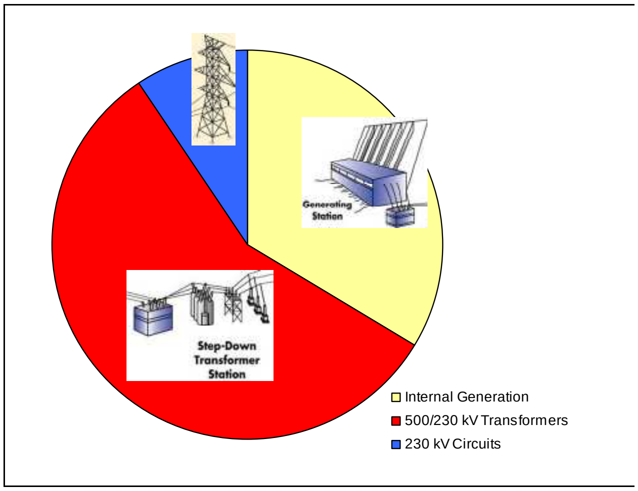
The following pie chart (Figure 2.57) illustrates the relative capability and contributions of the 500/230 kV transformers, the 230 kV lines and the internal generation to supply the GTA in 2005 and in 2010. The GTA continues to rely heavily on the transformer facilities to import power into the area. The 500/230 kV transformers make up two-thirds of the total GTA supply capacity. Internal generation makes up less than 25 percent of the supply capacity. Even though there are twelve 230 kV circuits connecting the GTA, they collectively provide about 12 percent of the supply capacity. The reason is that the 230 kV circuits north and east of the GTA are long circuits and are not connected to significant generation sources. Due to the electrical characteristics of the system, most of the power from generation sources finds its way to the GTA via the 500 kV system, rather than the 230 kV system.

Figure 2.57 – GTA Supply Capacity

GTA Supply Capacity Summer 2005



GTA Supply Capacity by 2010 with New Generation Procurements



Source: OPA and Hydro One Networks Inc.

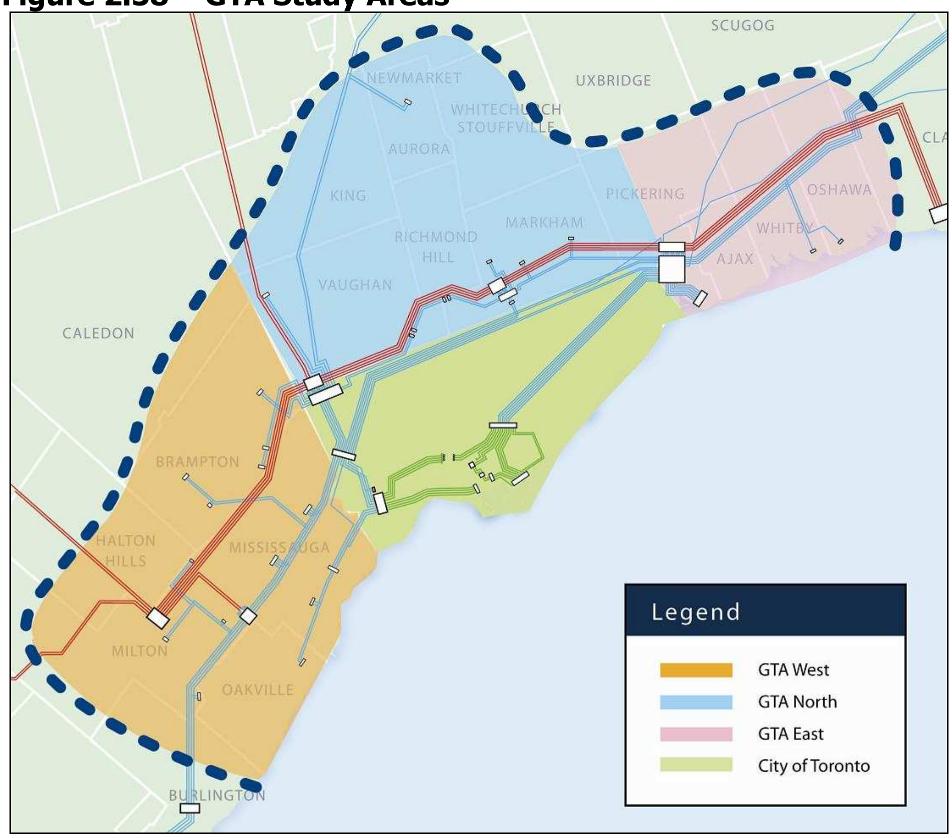
GTA Issues

Before exploring the options that address the GTA transmission needs, it is important to review the key issues and considerations that affect the transmission needs of the broader GTA system as well as the local areas. These are:

- supply capacity now and in the future
- supply security and system risk
- new generation and the need for a GTA "bypass"
- finding room for expansion.

To organize and facilitate the discussion of the GTA transmission system, the GTA is sub-divided into north, east, west and City of Toronto study areas as shown in Figure 2.58. These study areas are based mainly on electrical considerations and the electrical facilities within the defined boundaries. Such boundaries may not always line up with municipal boundaries.

Figure 2.58 – GTA Study Areas



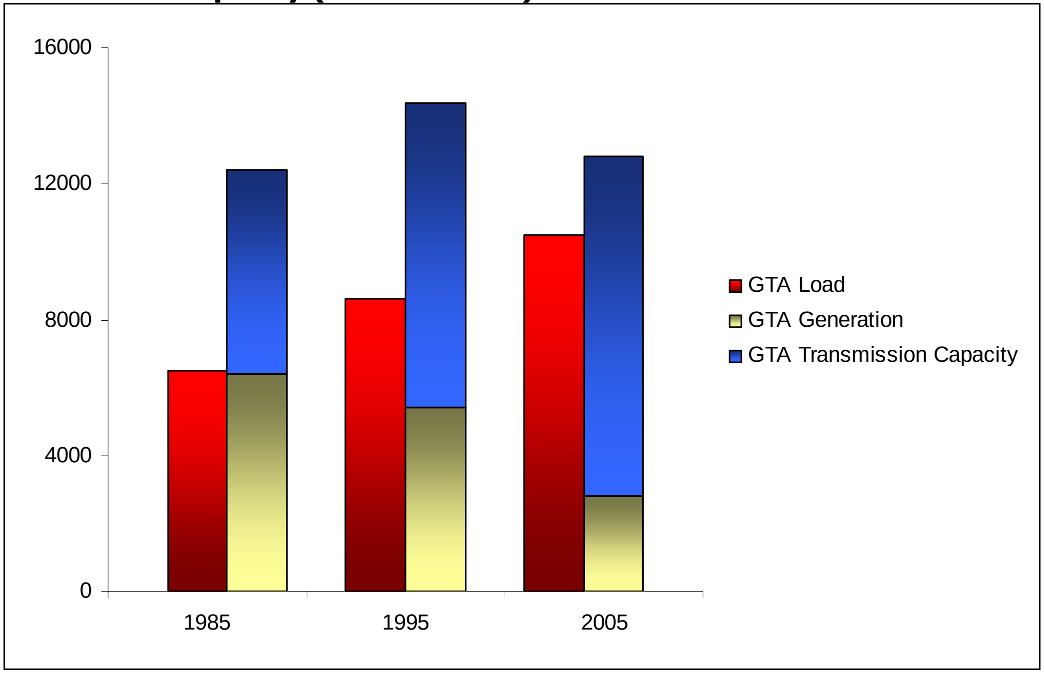
Source: IESO and OPA

Supply Capacity Now and in the Future

The immediate concern in the GTA relates to shrinking supply capacity margins and the need to be more self-sufficient for internal supply. Summer peak load in the GTA has grown consistently over the last 20 years, while internal generation has significantly decreased. New transmission has been added, but it has not kept pace with the gap between increasing loads and shrinking generation.

In 1985, the GTA area was nearly generation self-sufficient. Significant transmission capacity was available to accommodate unforeseen events and to provide the supply diversity for economical supply to the area. In the summer of 2005, with only 25 percent of the load supplied by internal sources (primarily from Pickering), the GTA relied heavily on the transmission system, with the lowest supply capacity margins in 20 years, to meet the high demand days. During several hot days that summer, all major transmission and generation facilities in the GTA were required to be available. An unforeseen loss of one or two key GTA transmission or generation facilities would have jeopardized the ability of the system to meet the GTA peak demand.

Figure 2.59 – GTA Summer Peak Load and Generation & Transmission Capacity (1985 to 2005)



Source: OPA

Since the summer of 2005, the GTA supply capacity has improved with the return of Pickering G1 and the addition of the second 500/230 kV transformer at the Parkway station. These additions were key to meeting the record system peak of 27,005 MW set this past summer. The new system peak eclipsed the previous record peak set in 2005 by over 800 MW.

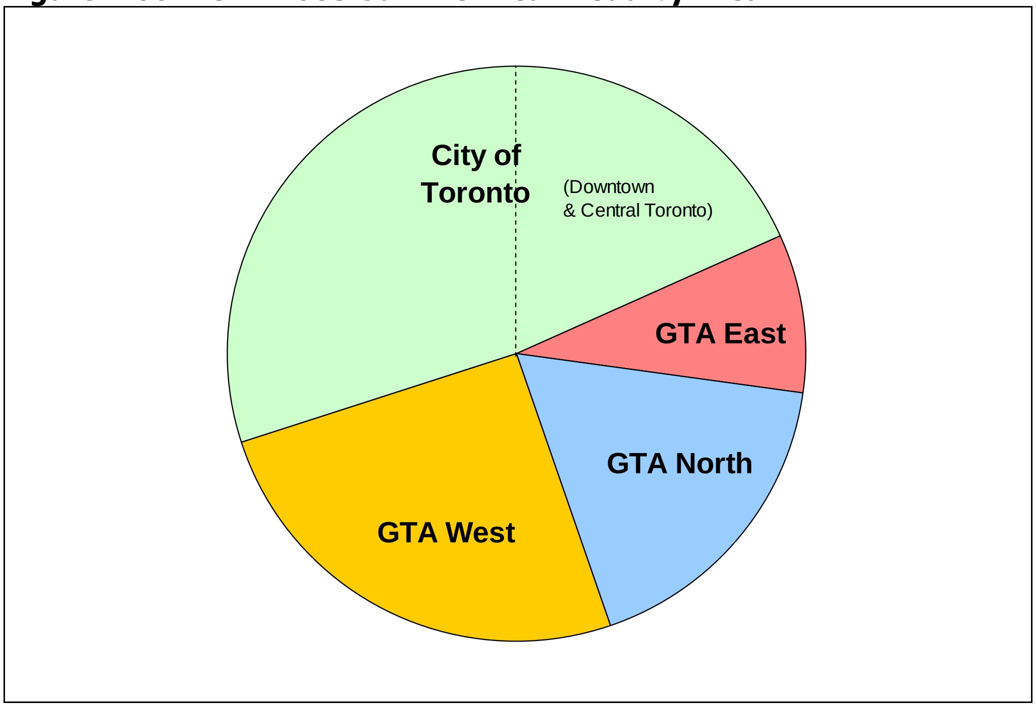
The near-term outlook will improve further with three new gas generation developments (Goreway Station, Portlands Energy Centre, GTA West) expected to be in service over the next four years. Both the Goreway Station and the Portlands Energy Centre are under construction.

While these projects were initiated mainly to address urgent local reliability issues where major transmission reinforcements could not be provided in time, they will add 2,000 MW of supply capacity for the GTA and contribute significantly to improving the capacity margins.

With load expected to grow in the GTA, there will be supply capacity issues beyond the near-term period. The load growth forecast for the City of Toronto over the next five years and the five to 10-year period are 0.8 percent and 1.2 percent annually. While these growth rates are more in line with the provincial average, the growth rates in the GTA's 905 areas are significantly higher. Over the next five years, the 905 area growth rates vary from 2.7 percent to 3.1 percent, and over the five to 10-year period, the rates vary from 2.0 to 3.0 percent. Areas in York, Peel and Halton regions have the highest projected growth in the province[3].

Figure 2.60 shows the load breakdown of the City of Toronto, GTA North, East and West areas. These are based on total loading at the stations that reside in each of the four study areas. The actual loads of the municipalities or local distribution companies (LDCs) may vary slightly. For example, the load stated for the City of Toronto will be higher than the loads recorded by Toronto Hydro Electric System (THES). Some load stations which are closer to the Toronto boundaries with other municipalities may supply not only THES but other distribution companies such as Enersource Hydro Mississauga, PowerStream and Veridian Connections.

Figure 2.60 – GTA 2005 Summer Peak Load by Area

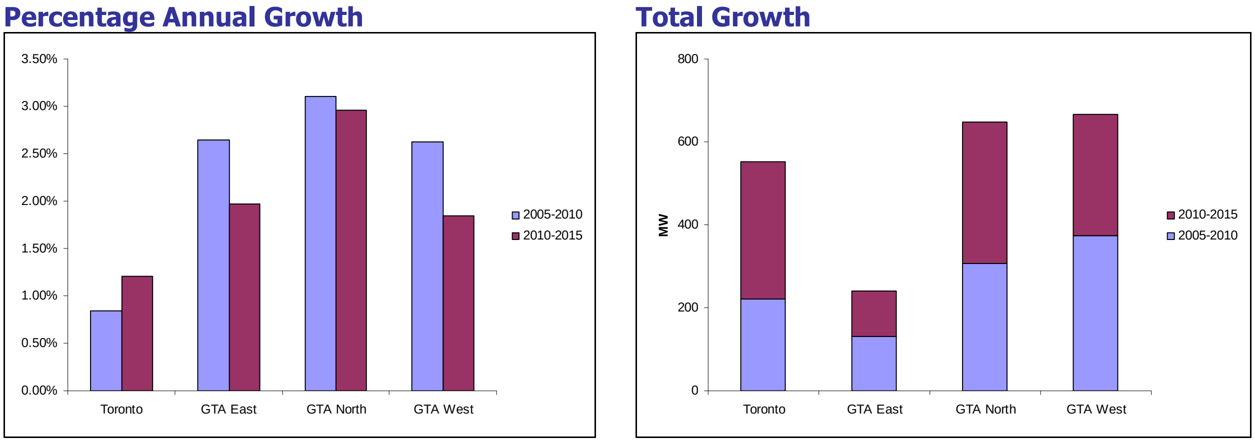


Source: GTA LDCs and OPA

[3] Load forecasts were provided by LDCs and do not include potential CDM initiatives, because insufficient information exists at this time on the amount of peak reduction to expect and how to attribute such reductions to specific stations.

Forecast growth for the GTA study areas is shown in Figure 2.61.These forecasts are based on LDC forecasts of station loadings, coincident with the sub-area peaks. The overall GTA average annual growth is expected to be about 1.8 percent per year over the next 10 years. At this rate, the GTA load would increase by 2,000 MW in 10 years and effectively absorb the new generation provided by the Goreway Station, Portlands Energy Centre and GTA West developments.

Figure 2.61 – GTA Forecast Load Growth by Area



Source: GTA LDCs and OPA

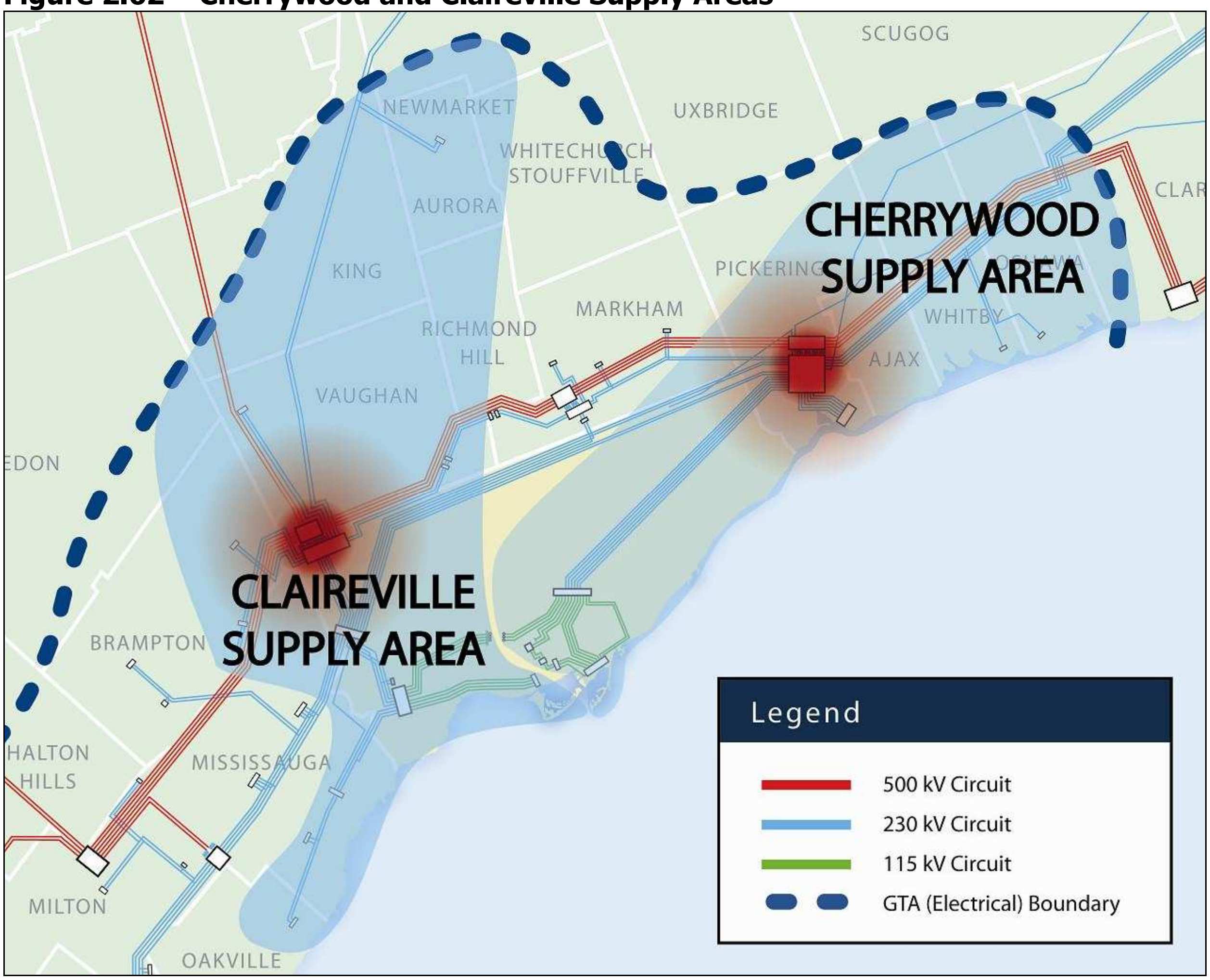
By 2015, not only will there be an overall supply capacity issue, but a number of transmission facilities throughout the GTA will have already reached capacity. For example, by 2013, the 500/230 kV transformers at the Claireville station will reach capacity. The Claireville transformers supply load in the west part of Toronto, as well as a number of areas, including Brampton, North Mississauga, Vaughan, Richmond Hill and Newmarket. In the absence of more generation, additional 500/230 kV transformer capacity will be required. The supply capacity for Claireville and other areas is discussed in greater detail in the GTA Transmission Options section.

Supply Security and System Risk

In addition to concerns with adequate supply capacity, the security of supply and risk of significant load loss when major disturbances occur are important considerations. With both greater intensification and land development within the GTA, there is not only more load to supply, but also fewer opportunities for new transmission supply paths. New locations to provide network reinforcements or new connection lines to supply new load stations are limited. As a result, it is often necessary to maximize the transfer capability on existing supply paths and install transmission facilities with ever higher capabilities. This results in a greater concentration, both physically and electrically, of transmission facilities and an increased risk of greater load loss due to extended outages of major facilities, multiple equipment failures, or extraordinary events (e.g., fire, flooding, tornado or ice storm). The risk increases further as many of the facilities are aging or reaching their end-of-life. While the probability of such events is quite low, their impacts on the GTA communities would be very high. There are a number of locations on the GTA system which warrant further consideration.

The Claireville and Cherrywood stations are arguably the most critical 500 kV stations. They both connect key 500 kV lines and each provide about 3,000 MW of transformation capability. Cherrywood also connects 3,000 MW of generation from Pickering. Together, Claireville and Cherrywood provide two-thirds of the supply to the GTA 230 kV system. Extraordinary events or major failures at either of these stations would result in prolonged interruption to a large part of the GTA. A complete loss of Cherrywood would affect nearly half the GTA load. While the load loss magnitude is not as great at Claireville, the risk of prolonged outages is much greater since Claireville uses gas-insulated switchgear (GIS). Failure or damage to GIS facilities requires much longer lead times to procure and install replacement equipment. Any further major expansion at Claireville or Cherrywood must assess the risk issues and give due consideration to expanding other stations or establishing new stations.

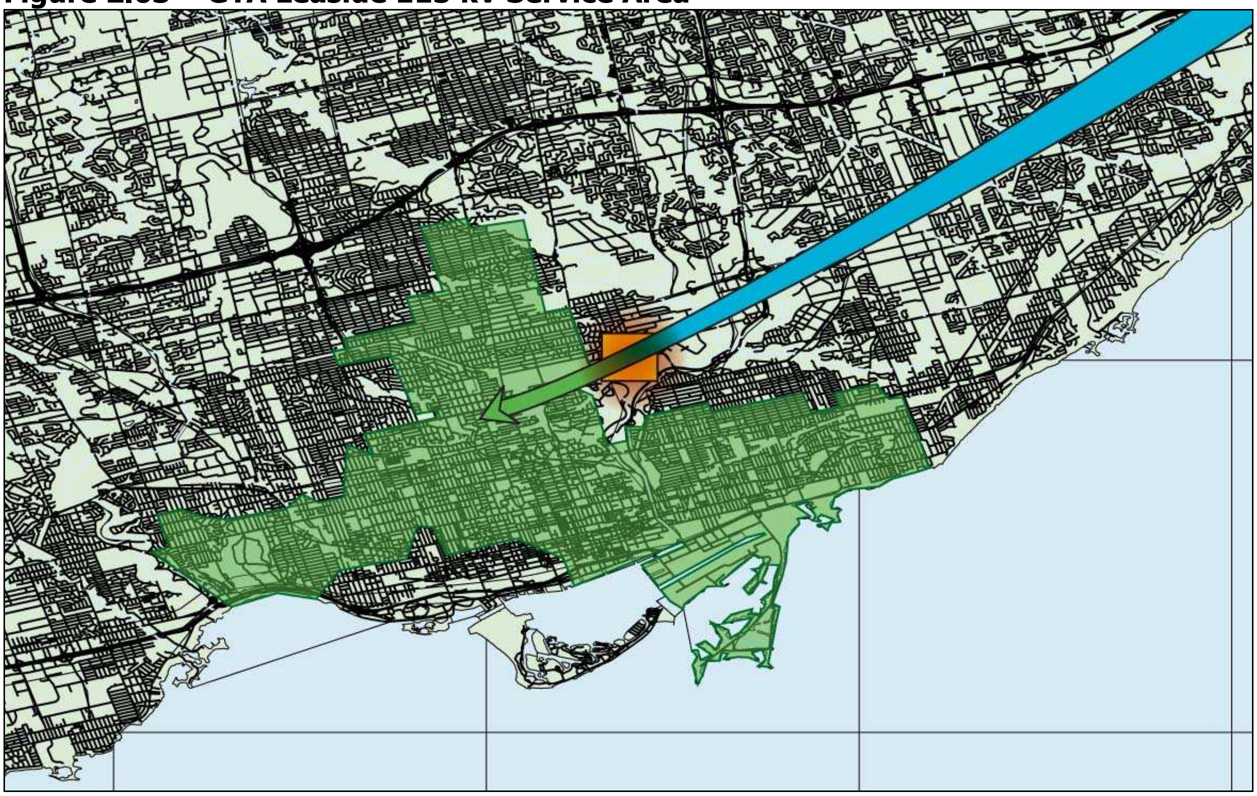
Figure 2.62 – Cherrywood and Claireville Supply Areas



Source: IESO and OPA

The supplies to central and downtown Toronto are other sub-systems where the concentration of facilities is of particular concern. Presently, both the Manby and Leaside stations represent the only source of supply to the 115 kV systems. The Manby 115 kV system supplies over 700 MW of load, including most of the financial district load in the downtown core. The Leaside 115 kV system supplies 1,300 MW of load, including many of the major hospitals in the downtown area. Figure 2.63 shows the single supply path to the Leaside station and illustrates the extent of the service area supplied by the Leaside 115 kV system.

Figure 2.63 – GTA Leaside 115 kV Service Area

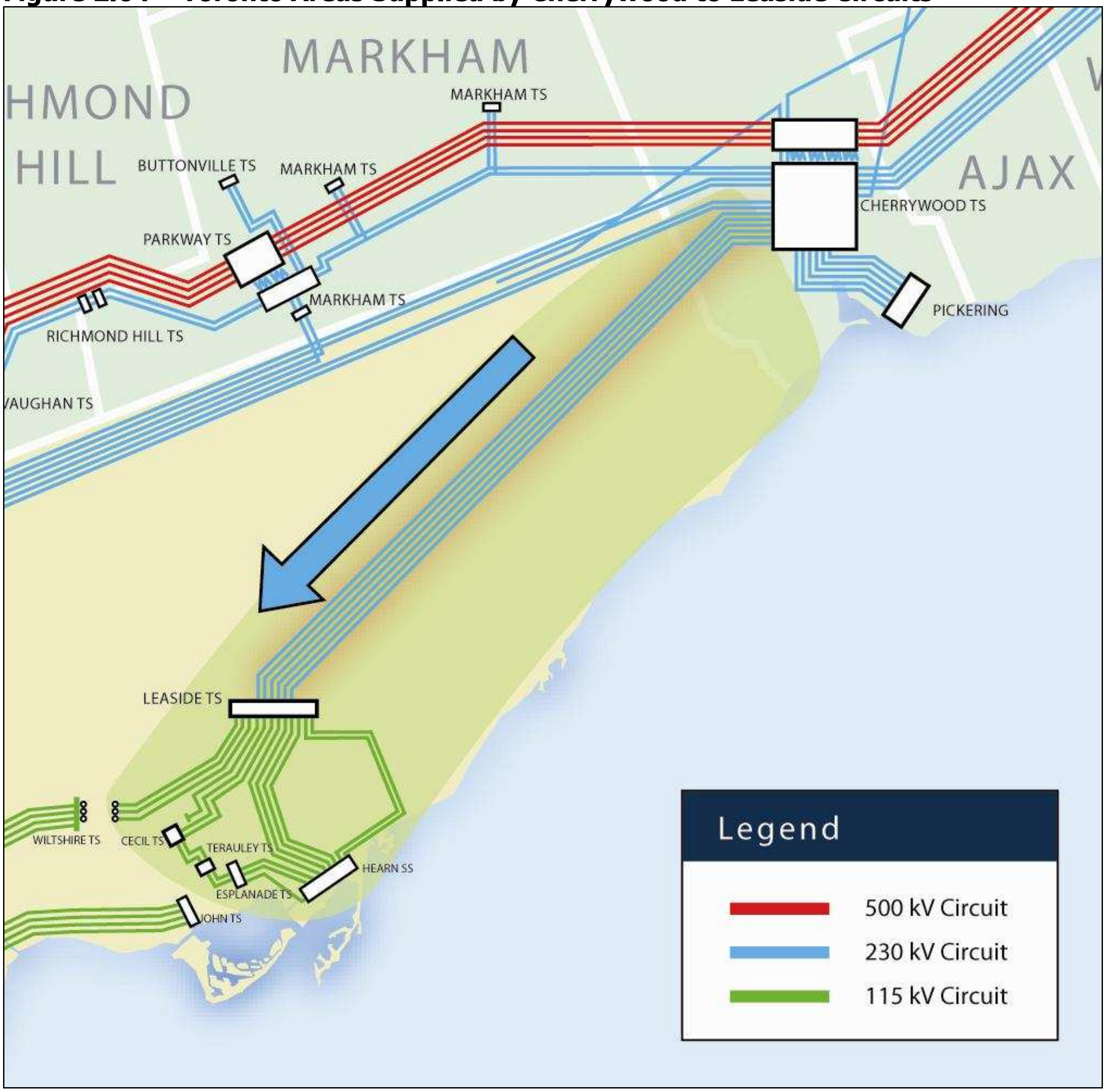


Source: Toronto Hydro Electric System and OPA

There is a limited capability of about 400 to 500 MW for any one system to transfer load to the other under emergency conditions. If either station is lost due to an extraordinary event, significant amounts of load would be unsupplied for extended periods. There are presently no means to fully back up either station. Further adding to the security risk is the concern for aging facilities. Nearly all of the 115 kV underground cables are over 25 years old and half of these are at least 40 years old. The risk is compounded by the high loading levels on the 115 kV system, which means it is difficult to obtain long "outage windows" to refurbish or replace these aging facilities in a timely manner. Should multiple elements of similar vintage fail at the same time, it may not be possible to replace them all in a short period of time.

The 230 kV supply circuits on the Cherrywood to Leaside corridor are the sole geographic path to supply the Leaside station and a number of 230 kV load stations in the Scarborough area. The total load, including the Leaside 115 kV loads connected to these 230 kV circuits, is 2,300 MW. This is a sizable amount of load that would be at risk from weather events that may take the transmission corridor out of operation. Figure 2.64 conceptually shows the approximate service area supplied by the Cherrywood to Leaside circuits.

Figure 2.64 – Toronto Areas Supplied by Cherrywood to Leaside Circuits



Source: IESO and OPA

Another important security concern is the significant requirement for voltage support and control capability for the GTA transmission system. Maintaining a proper voltage profile and system voltages at high enough levels is critical for system security and integrity. Strong voltages also reduce losses on the system.

Reactive power, expressed in units of Mvar, is required to support voltages. Reactive power must be provided locally where voltage support is needed. Reactive power sources traditionally include generators and capacitor banks. Generators provide reactive power that is "dynamic" in that there are control systems which can adjust nearly instantaneously and maintain constant reactive output that is insensitive to changes in system voltage. Capacitor banks provide reactive power that is "static," in that there are no active systems and their reactive output can vary widely with changes to system voltage. Other devices, which provide reactive power that is more similar to the dynamic manner of generators, include static var compensators (SVC) and static compensators (STATCOM).

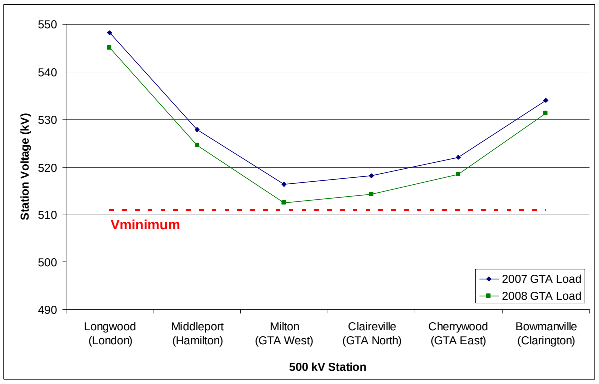
Generators internal to the GTA provide not only active power to supply the load, but also reactive power to support the system voltage. In the absence of additional generation, there is greater reliance on the existing transmission system to import higher levels of power into the GTA. In a simplified example, one additional MW of load may require 0.5 Mvar of output from a nearby internal generator to support that load. But if the power is brought in via the 500/230/115 kV network, the reactive power required may be two Mvar or more. The higher the transfer through the existing transmission network, the greater the reactive power consumption. Adding transmission facilities, such as new lines and transformers, can off-load existing facilities and reduce the reactive power need.

In response to decreasing internal generation and increasing load, adding capacitor banks has been the primary means of providing the required reactive power to support the GTA voltages over the last 15 years. During this period, nearly 3,000 Mvar of high voltage and 1,500 Mvar of low voltage (distribution level) capacitor banks have been installed in the GTA. The GTA is compensated at a high level with static capacitor banks. In fact, the largest 230 kV capacitor banks in eastern North America are found in the GTA. While capacitor banks are an economical means to provide reactive power, there is a limit to the amount that can be installed on the system. Capacitor banks lose their effectiveness when voltages decline, which is when they are needed the most. Excessive use of capacitor banks can result in a false sense of security, where voltage instability can occur even at relatively high operating voltages following a disturbance to the system. Other devices, such as SVCs and STATCOMs, which fluctuate less with voltage, are available but are much more costly.

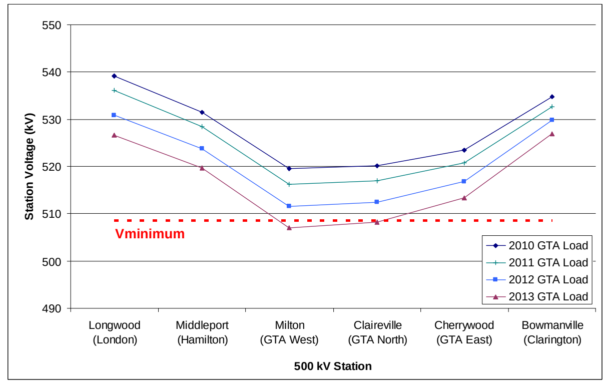
Plots of the GTA voltage as a function of the GTA load are shown in Figure 2.65. The voltage profile plots with the 2007 transmission and internal generation facilities show that voltage performance is adequate for 2007-2008. The balance of the Goreway Station and the first phase of the Portlands Energy Centre (PEC) are expected to be in service by 2008 and will provide adequate voltage support until 2010. By 2010, the balance of the PEC development will be completed and the 600 MW GTA West facility will be in service. These projects will provide adequate voltage support until 2012, as shown in the voltage profile plots for the 2010 conditions. Beyond 2012, significant additional voltage support will be required to ensure adequate voltage performance in the GTA. This could be provided by transmission reinforcement or additional internal generation.

Figure 2.65 – Post Contingency System Voltage Profile

2007 GTA Generation Conditions



2010 GTA Generation Conditions



Source: IESO

In the GTA Transmission Options section of this paper, further discussion can be found regarding the GTA system voltage and reactive power support and how the transmission projects can help to address these issues in the medium to longer-term timeframe.

New Generation and Need for a GTA "Bypass"

With many discussions underway for new major developments to replace coal-fired generation and to use more renewable sources of generation, the generation landscape will be changing significantly over the next 20 years. The existing bulk transmission system was largely designed to deliver power from existing generation sites to the GTA and the Golden Horseshoe area. With large generation facilities retiring and new major sources appearing in different locations, flow patterns can change dramatically.

In the 2015 to 2025 time period, major new generation developments could occur in the western, northern and eastern areas of the province. A number of new generation developments are given in the resource discussion paper (#4) and have also been articulated by industry stakeholders. Such developments could include:

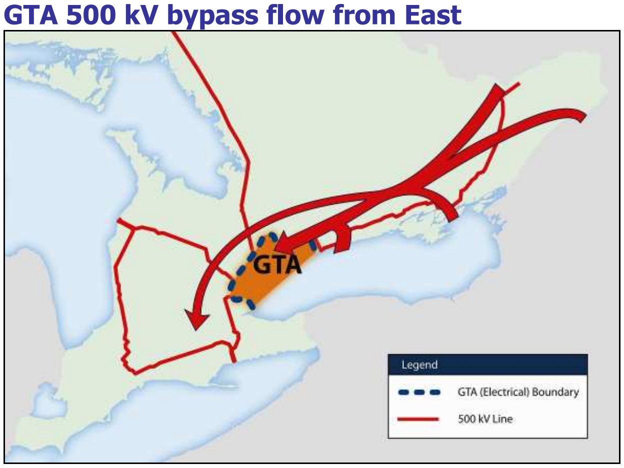
- in the west: nuclear expansion at Bruce GS and more wind developments in the Bruce and southwestern Ontario areas
- in the north: hydroelectric and wind developments
- in the east: nuclear expansion at Darlington GS, major imports from Quebec and wind developments in the Prince Edward County and Cobden/Pembroke areas.

Depending on the timing and types of new generation developments, power transfer levels to the GTA could be much larger and in different directions than were originally contemplated in the design of the present system. Existing 500 kV paths into the GTA may need to be reinforced or reconfiguration of the 230 kV network may be required to redirect the higher flows.

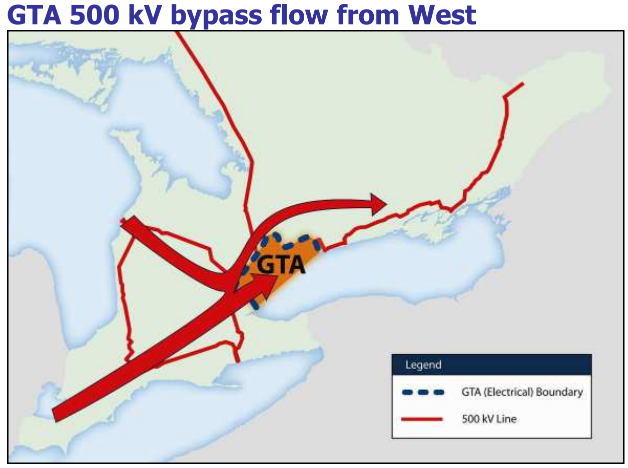
For even higher transfer levels, new 500 kV transmission may be required to redirect large amounts of power across the GTA to other areas in the province. The GTA 500 kV system may need to act, more so than today, as a hub for large-scale switching of power. A potential scenario could have high eastbound flows through the GTA during the day, and high westbound flows through the GTA during the night. Such a scenario could occur with large scale development of wind in the west and large scale generation or imports from the east. New 500 kV facilities would be needed to "bypass" the overflow of excess power flow from any one direction around the GTA. The need for such transmission facilities would not be expected before the 2015-2020 timeframe and would be strongly linked to generation development schedules.

Figure 2.66 – GTA - 500 kV Bypass Flows

GTA 500 kV bypass flow from East



GTA 500 kV bypass flow from West



Source: IESO and OPA

While the discussion in this section has been focused on transmission issues associated with new generation developments, the decision on whether to retire or refurbish a large internal generation facility such as the four Pickering B units has a significant impact on the GTA transmission system. If the Pickering B units are not refurbished, then a number of issues would need to be addressed, including replacement supply, capacity of the Cherrywood transformers and the 230 kV system, system voltage support and security risk. Due its importance to the GTA system, the transmission changes required would likely be complex and extensive.

Finding Room for Expansion

There are two considerations in finding room for expansion: electrical room and physical room. While physical room relates to the actual space available to install new station equipment or to route a new transmission line, electrical room is concerned with the system's ability to incorporate new transmission and generation facilities. The GTA transmission system is strongly meshed with many interconnecting lines at the 500 kV and 230 kV levels. While this provides a good level of reliability and operational flexibility, it also means that short-circuit levels can be quite high.

The short-circuit capability of transmission station equipment reflects its ability to withstand the large currents, typically tens of thousands of amps, flowing through the equipment when there is a short circuit caused by a disturbance or equipment failure. The equipment must be able to withstand the high short-circuit currents until protection systems can operate and clear the problem.

Adequately rating equipment to handle maximum expected short-circuit levels is a critical safety requirement. Inadequate facilities can lead to explosive failures that can not only injure personnel at the stations, but also result in extensive damage to other key station facilities.

There are a number of key stations in the GTA where short-circuit levels are high and approaching the equipment capability. These stations are Claireville, Richview, and Cherrywood on the 230 kV system and Leaside and Manby on the 115 kV system. Station facilities at Claireville, Cherrywood and Richview already have some of the highest short-circuit capabilities available. Installing higher rated equipment is not feasible for these stations; moreover such equipment may not even be available.

Reconfigurations at these stations have been or are taking place to split up station switchyards electrically to reduce short-circuit levels. The drawback to this effort is that reliability is significantly reduced each time a station switchyard is split. As a result, switchyards are generally split no more than once before there is an adverse reliability impact. In some locations, such as Cherrywood and Leaside, where there is generation nearby, each switchyard at the station must be operated in a split mode depending on the number of generating units operating. Once the new Goreway Station, Portlands Energy Centre (PEC) and GTA West generation is in service, Claireville, Richview, and Leaside switchyards are expected to be operated in split mode for normal operations.

With limited short-circuit capacity at many of the key GTA stations, there is only a limited amount of new transmission or transmission-connected generation that can be installed. Not only is the size restricted, but the type and siting options for new facilities are also limited. For example, once PEC is completed, there is no remaining short-circuit capability to site more generation on the Leaside 115 kV system without a major rebuild of the Leaside switchyard. Even following the 230 kV switchyard split at Claireville and notwithstanding the risks discussed above, adding more 500/230 kV transformers at Claireville may not be possible without extensive work and costs.

Eventually, when short-circuit capacity runs out, station rebuilds, where technically possible, or major reconfigurations of the bulk GTA transmission system will be required. These are large-scale and long-term investments that can collectively, over time, cost several hundred million dollars. As a result of high loading levels in so many places in the GTA, long-term outages for such major changes cannot be scheduled easily and expensive temporary or bypass facilities must be constructed. The timing of and need for such investments will largely depend on the transmission and generation facilities required to meet the near- and medium-term needs of the GTA.

The lack of physical room is a problem for both near-term load supply and risk and long-term bulk system expansion. Not only is available space limited at existing stations, but land and corridor space earmarked 30 years ago is also nearly all used up. Past planners had the foresight 30 years ago to designate a corridor on the Parkway Belt lands (which includes many of the 400-series highways) for transmission development to meet the GTA growth. Only a small amount of this space remains today for new transmission. It is, therefore, critical to ensure that this space be preserved and that any changes to the Parkway Belt land usage will not limit the ability to use these lands for future transmission purposes.

At present, no new significant lands have been designated for transmission in the GTA to service areas between the parkway belt corridor lands and the recently designated green belt lands. The OPA recognizes the need to work closely with other provincial and municipal planning agencies to ensure adequate transmission facilities are in place to support the desired future development, just as would be the case for transportation, water and wastewater facilities. The OPA will seek opportunities to identify transmission needs when multi-use infrastructure corridors are being planned by municipalities.

Establishing new rights of way will be extremely difficult in developed areas. Where it is not technically possible to establish a new overhead transmission line, underground transmission options will need to be considered. However, even underground projects present significant challenges in dense urban areas such as downtown Toronto. For example, in the case of the John to Esplanade Link project currently under construction, Hydro One Networks determined that boring a tunnel 20 metres underneath the downtown core was more feasible than laying trenches beneath the surface. The decision to tunnel was based on the cost and complexity of designing around the myriad of existing infrastructure components (distribution cables, gas lines, fibre optic networks, traffic control systems, communication lines, water pipes, sewage systems, TTC, etc.), and on avoiding significant disruption to activity in the downtown core.

New “greenfield” transmission routes in the GTA will also be an issue. They are expensive given the high cost of land in the GTA and developing them will be complicated by the interests of many stakeholders with strong sentiments. Fierce opposition has even been encountered for transmission projects on existing rights of way.

For local load supply within the GTA, the biggest current challenge is providing additional supply circuits in the GTA West (west Brampton, Halton Hills, Milton) and in the GTA North (Aurora, Markham, King, Newmarket, Vaughan). These areas have been growing rapidly and are expected to continue growing over the next 10 years or more. However, there is currently very limited 230 kV infrastructure available to meet this growth.

GTA Transmission Options

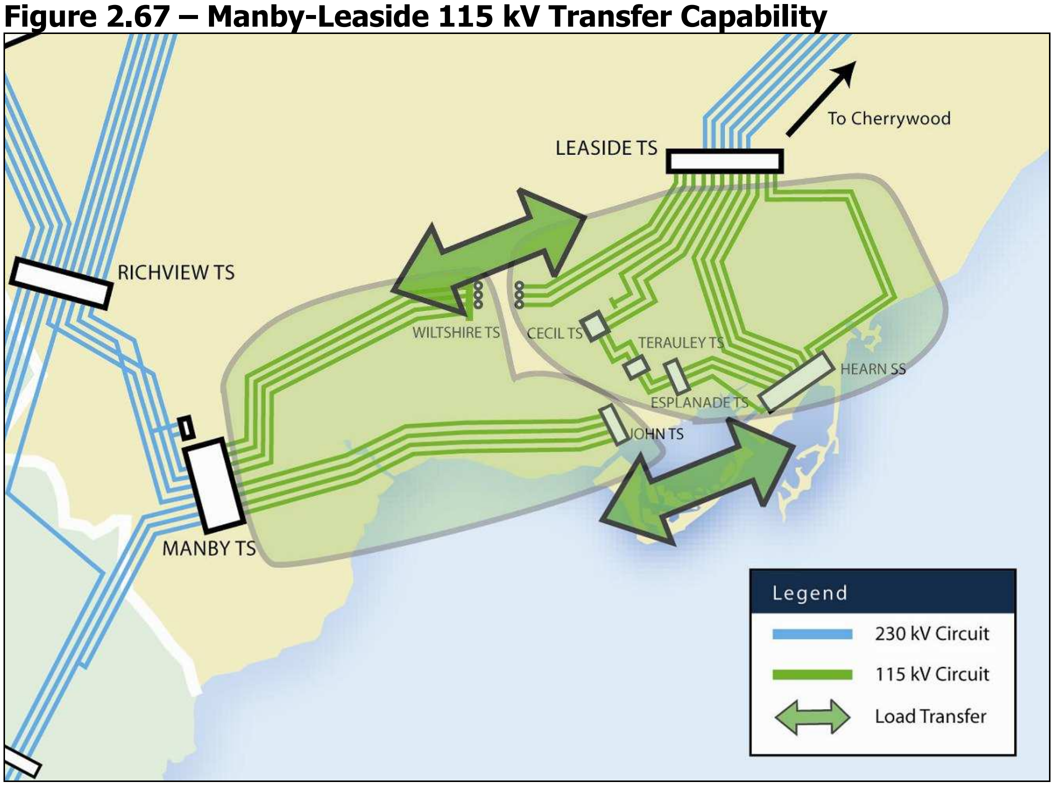
This section discusses in more detail the potential solutions to many of the issues described above, including transmission options in the four GTA study areas. Facilities residing in one part of the GTA generally provide significant support and benefits to other parts of the GTA. It should be noted once more that the electrical boundaries have a limited correlation with the municipal boundaries. While some facilities may have a more local focus, all facilities contribute to the overall supply and security of the GTA system.

While many of the transmission options may address a number of different needs, an overall theme emerges for each of the study areas in the GTA. In the City of Toronto, the key issue is security and risk of supply to central and downtown Toronto. In the GTA North, the need is to relieve the loading on the Claireville 500/230 kV transformers and further development of Parkway for the long-term supply needs of York Region. In the GTA West, the main concern is new transmission to address load supply for the fast growing areas in Peel and Halton Regions. In the GTA East, the key issue is changes in generation facilities, whether related to major new developments or retirement of Pickering B units.

City of Toronto

As discussed earlier, central and downtown Toronto are supplied out of only two stations, Manby and Leaside, which transform the 230 kV supply to 115 kV for subsequent delivery to the load stations where it is received by Toronto Hydro Electric Systems (THES) for distribution. Also noted earlier, the 115 kV systems supplied from each station are electrically isolated. Some switching facilities exist to transfer some load from one system to the other. Load transfers are necessary to perform maintenance and to provide emergency supply. However, the ability to transfer load capability between the two systems is limited, as there is only about 400-500 MW of emergency transfer capability between the two systems. Transfer capability for normal operation (i.e., for maintenance) is much lower, at 250-300 MW.

Figure 2.67 – Manby-Leaside 115 kV Transfer Capability



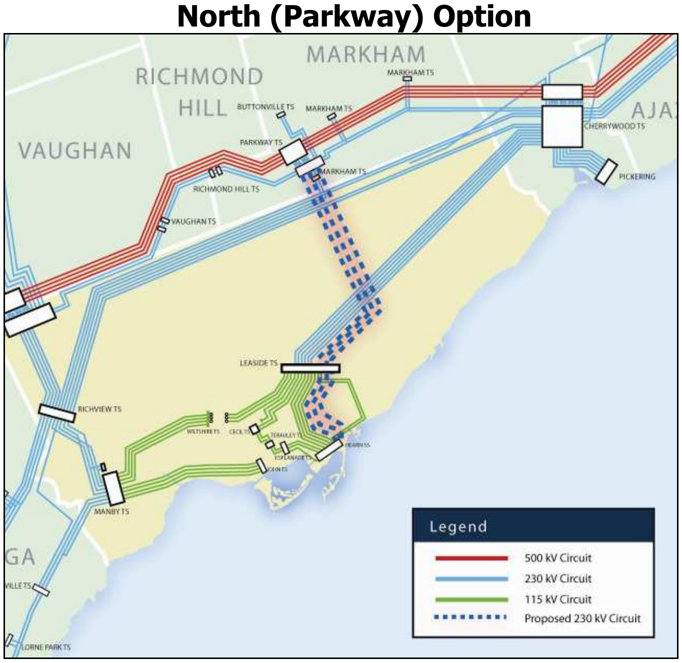
Source: IESO and OPA

There is presently no means for either 115 kV system to fully back up the other system in case a catastrophic event affects Manby or Leaside. While the Portlands Energy Centre project, with 550 MW of generation, would help mitigate the load loss and outage duration, there would still be areas on both 115 kV systems that would experience prolonged rotating outages.

The risk is further exacerbated by the fact that the six 230 kV circuits running into Leaside from Cherrywood are all on the same power corridor. Should an extraordinary weather event result in the loss of this corridor, loads supplying either the 115 kV system or the 230 kV circuits would be impacted, with an immediate loss of 2,300 MW of load. The loss of the Richview to Manby 230 kV corridor would not be as severe because the 115 kV loads are lower and the stations normally supplied by 230 kV circuits could be restored from Cooksville. However, not all of the Manby 115 kV load could be transferred to the Leaside 115 kV system, and some load would still be subjected to rotating outages.

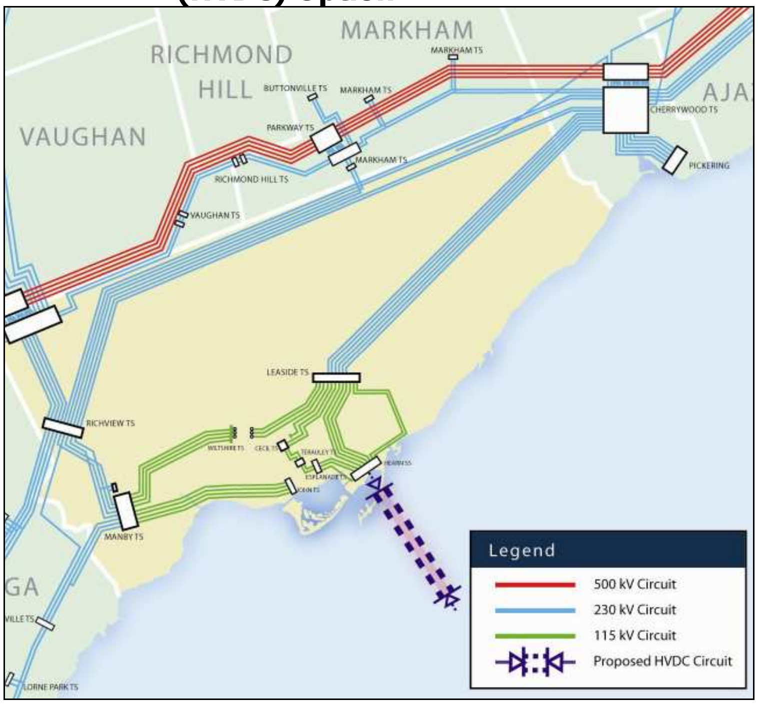
All potential solutions to address the central and downtown Toronto security risk involve the concept of a third supply point connected at the Hearn station. With a third supply point, the 115 kV systems could be fully backed up even for a catastrophic loss to any one station (Leaside, Manby or Hearn). Under normal conditions, each station would supply a portion of the 115 kV system independently. Under emergency conditions, switching facilities would be provided to transfer approximately half the load of one 115 kV subsystem to the other two subsystems. There are presently three options to provide a third supply. Each option proposes a new supply from a different direction – north, west and south – and brings a new supply path with 500 to 700 MW of capacity into Hearn, at costs ranging from $500-600 million.

Figure 2.68 – Toronto Third Supply Options: North (Parkway) Option



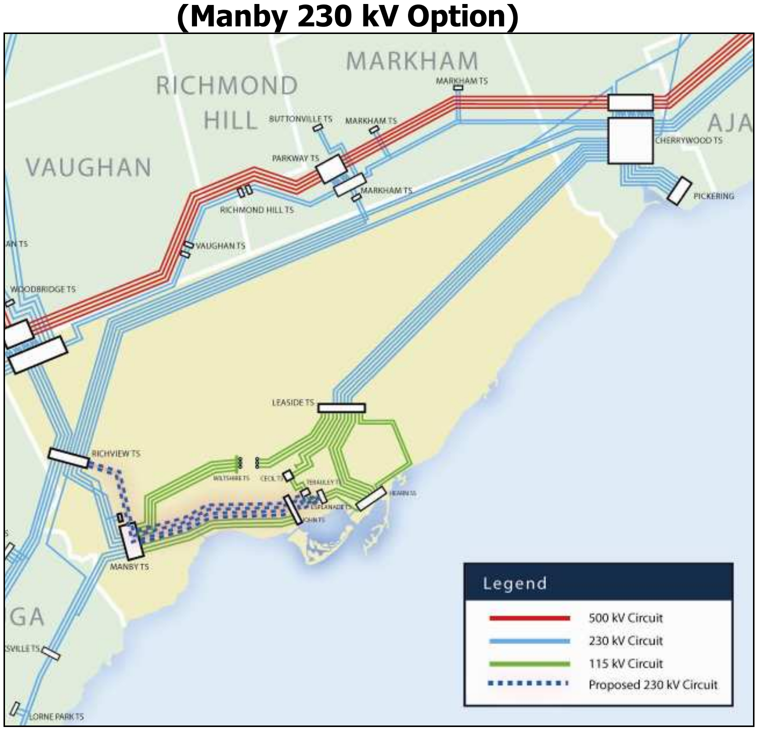
Source: Hydro One Networks Inc., IESO and OPA

Figure 2.69 – Toronto Third Supply Options: South (HVDC) Option



Source: Hydro One Networks Inc., IESO and OPA

Figure 2.70 – Toronto Third Supply Options: West (Manby 230 kV Option)



Source: Hydro One Networks Inc., IESO and OPA

The third supply option from the north involves expansion at the Parkway station. A new 500/230 kV transformer will be required in addition to the two existing ones. Three new 230 kV circuits – approximately 25 km long – would be routed along a combination of existing corridors, where available, and road allowances from the Parkway to the Hearn stations. At Hearn, up to three 230/115 kV transformers would be installed to connect to the 115 kV system.

The third supply option from the south involves a high voltage direct current (HVDC) connection to Hearn via an underwater cable under Lake Ontario. The cable could connect to potential source points, such as Niagara, or to generation facilities near the Lake Ontario shore in New York State. The advantage of such a connection is that it would provide another generation source connection to not only support central and downtown Toronto, but the GTA as a whole. While a potential disadvantage of this proposal is that expensive HVDC station facilities would be required, it has the added benefit of not increasing short-circuit levels. This would provide greater operational flexibility in configuring the Leaside 115 kV system.

The third supply option from the west involves a path from the Richview and Manby stations. A new 230 kV double-circuit line approximately seven km long would be required between Richview and Manby. From Manby to Hearn, three 230 kV circuits, approximately 20 km long, would be required. Only part of the supply would be routed on existing corridors. For more than half of the supply, new right-of-way space will be required. This option provides less diversity than the other two options because the new supply and the Manby supply will emanate from the same source, the Richview station. Also, the new supply will put additional loading on transmission facilities further upstream, such as the Claireville transformers in the GTA North and the Trafalgar to Richview corridor in the GTA West.

In addition to the security risk issues discussed above, by 2015, supply capacity issues will emerge in central and downtown Toronto. The capacity of the Cherrywood to Leaside 230 kV circuits, which supply much of the Scarborough area and the Leaside 115 kV system, will be exceeded by 2015. The 230/115 kV transformer capacity at Leaside is not far behind and will be exceeded by 2017. These need dates assume that the Portlands Energy Centre generation will be fully in-service by 2010. Due to short-circuit limitations, both additional generation and major transmission upgrades cannot be added without rebuilding the Leaside station. Even if Leaside was rebuilt, much of the 115 kV and 230 kV facilities into Leaside would require reinforcement for significant capacity improvements. Other issues, such as limited space and the ability to take outages, could further limit the possible improvements. With little or no ability to feasibly expand the existing facilities, a new supply path, such as a third supply, would be required.

The timing for a third supply depends on a number of factors. If solely based on capacity needs, then a third supply could be required as early as 2015. However, given the security risk issues discussed as well as concerns for aging infrastructure, operation flexibility, and the ability to take long outages for maintenance, a third supply may be required sooner. THES, in consultation with Hydro One Networks, is presently reviewing the impact of these considerations on the timing of third supply options for the needs of central and downtown Toronto customers. From a bulk system perspective, a third supply may be required sooner to address Pickering B retirement or refurbishment programs. This is discussed further in the GTA East subsection.

There also are supply capacity issues in the immediate and near term. The facilities of immediate concern are the 115 kV circuits from Leaside to Birch Junction that supply the Bridgeman and Dufferin load stations in central Toronto. The loadings observed in the summers of 2005 and 2006 exceeded the circuit capacity. To address this urgent need, Hydro One is presently developing a plan to provide the necessary reinforcement. Approvals for this plan will be sought shortly.

In the near term, the 230/115 kV transformers at the Leaside station and the 230 kV circuits supplying Leaside from Cherrywood will reach capacity by 2008. To address the near- and medium-term supply needs, the OPA has contracted for the development of the Portlands Energy Centre, a 550 MW combined cycle gas generation facility to be connected at the Hearn station. The first phase of this project is to be in service for the 2008 summer period. The second phase is scheduled for completion in the summer of 2010. This generation facility will not only provide timely relief of the transmission facilities but also improves security of supply. It will significantly increase supply diversity and mitigate the risk of those events that can result in multiple outages to upstream transmission facilities.

The four 230 kV circuits from Richview to Manby will reach capacity by 2010. These circuits supply the Manby 115 kV system as well as parts of western Toronto, southern Mississauga and Oakville. There are two possible options to provide relief to this corridor. One option is to rebuild the existing 115 kV tower line presently being used for distribution to a 230 kV tower line. Another option is to build a new eight km long double-circuit 230 kV line from the Trafalgar station to connect to the 230 kV circuits supplying the Oakville load station. This new line would be routed through lands reserved for transmission line corridors as part of the Parkway Belt West Plan. This option has the added benefit of providing relief for the Trafalgar to Richview circuits and is discussed further in the GTA West subsection on transmission options. Both options are shown in Figure 2.71.

Figure 2.71 – Richview to Manby Supply Capacity Upgrade Options

Richview to Manby

Trafalgar to Oakville

Source: IESO and OPA

GTA North

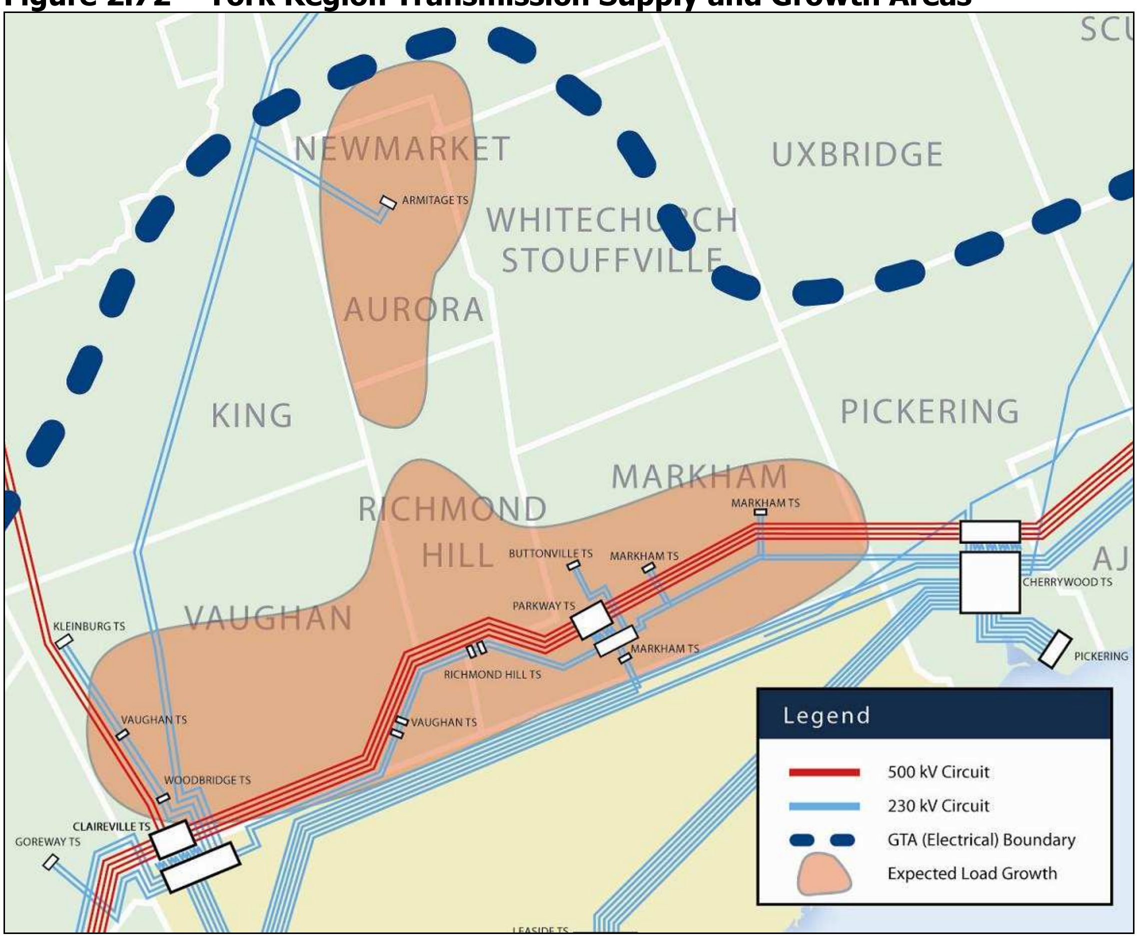
The 500/230 kV transformation at the Claireville station will be at capacity by 2013. As mentioned previously, adding new transformers will be technically challenging and costly because of high short-circuit levels and complex gas-insulated switchgear (GIS) equipment. Following the major station refurbishment and modification work that will be shortly underway, the 230 kV switchyard at Claireville will be configured for split mode operation. The consequence of this is that additional transformers will need to be installed in pairs to maintain an appropriate flow balance on the two halves of the switchyard. Another key concern for expansion at Claireville is the concentration of facilities and the amount of load that will rely on Claireville for supply.

An alternative solution to the Claireville capacity issue is to expand the Parkway station for York Region loads and the Milton station for Peel and Halton Region loads. Both stations have room to expand. The expansions would diversify the risk at Claireville and are likely to be less costly than the Claireville solution. Parkway is a new air-insulated station that can easily accommodate additional transformers. Milton SS presently doesn't have a 230 kV switchyard, but space exists at the station for extensive 230 kV GIS facilities. There may be opportunities to design an air-insulated switchyard depending on the ultimate future requirements. Some reconfiguration of the 230 kV network will be required to transfer the loads currently supplied by Claireville to either Parkway or Milton.

Both Parkway and Milton may be expanded for purposes other than relief to Claireville. Establishing a third supply for central and downtown Toronto from Parkway would require more 500/230 kV transformation capability. The timing for a third supply option could align with the capacity relief for Claireville. The GTA West section will describe in greater detail the need for expanding Milton as soon as 2014 to address load supply issues for Brampton, Milton and Halton Hills. The transmission plans for both Parkway and Milton may address the Claireville transformer capacity and supply risk issues. This provides opportunities to maximise the benefits of these transmission investments.

The OPA extensively studied the need and solutions for northern York Region in the summer of 2005. There was a significant level of community involvement and input in the course of that study, which resulted in the identification of an urgent need to augment the electricity supply to the region. The recommended plan contains a number of components, including: a new transformer station near Holland Junction, a demand management program and local generation in the area. The first and second components are proceeding. The local generation solution, which represents the high value use of gas-fired generation, will be initiated shortly. In the event that a successful procurement contract for local generation cannot be concluded, the alternative option is to upgrade the line from the Buttonville station to Gormley with a double-circuit 230 kV line and build a transformer station at Gormley.

Figure 2.72 – York Region Transmission Supply and Growth Areas



Source: IESO and OPA

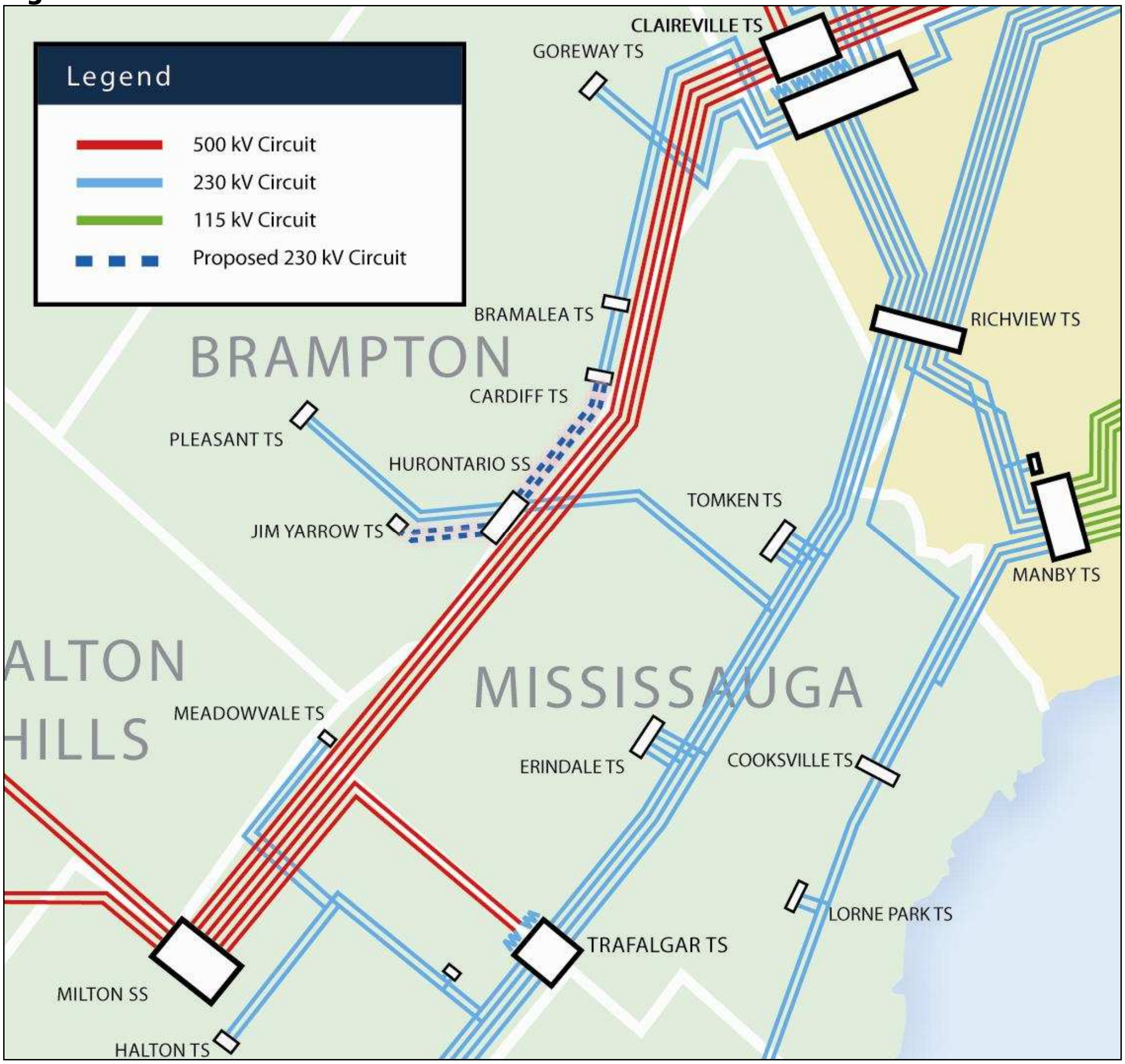
Beyond 2020, additional infrastructure will be required to support the growing loading in York Region. The current limited transmission capacity to northern and central York Region will be used up. Figure 2.72 illustrates the York Region transmission supply and growth areas. Other than the 230 kV circuits from Claireville supplying the Armitage stations and the 230 kV circuits from Parkway supplying the Buttonville station, there are no other supply lines or points. Also, by 2020, the existing 230 kV lines along the 407 highway likely will be at capacity. Presently there is some room to connect one or two new stations for supply to the Vaughan and Markham areas. However, such stations may require more distribution infrastructure to bring the power northward to load areas. Consideration will need to be given for new a supply point into the area to address long-term needs.

GTA West

The main issues for the GTA West pertain to supply capacity. Presently, the 230 kV circuits from Trafalgar to Richview which supply Mississauga, Brampton and Halton Hills, are at capacity. To address this urgent need, Hydro One has filed a leave to construct application with the Ontario Energy Board (OEB) for an extension of the 230 kV circuits along the 407 highway corridor to connect to the Trafalgar to Richview circuits at a proposed Hurontario station. The target in-service date for this work is May 2009. Hydro One will also be initiating environmental assessment work for the reinforcement of the line section from the Hurontario station to Jim Yarrow load station. While a firm in-service date has not yet been established for the reinforcement work to Jim Yarrow, it is proceeding on an urgent need basis and is targeted to be in-service as soon as possible following the Hurontario station work. Hydro One and the affected LDCs have established interim mitigation measures until the new facilities are in place.

Another near-term supply capacity issue is the loading of the 500/230 kV transformers at the Trafalgar station. These transformers will reach capacity by 2010. To address this need, the Minister of Energy directed the OPA to procure up to 1,000 MW of generation in the Trafalgar vicinity. The OPA issued a Request for Qualifications in November 2005 which closed in early 2006. In April 2006, the OPA issued the GTA West Trafalgar request for proposals (RFP) for 500 MW-600 MW of clean generation to be installed by June 1, 2010. The closing date for RFP submissions was September 27, 2006 and the successful participant is expected to be announced by mid-November 2006.

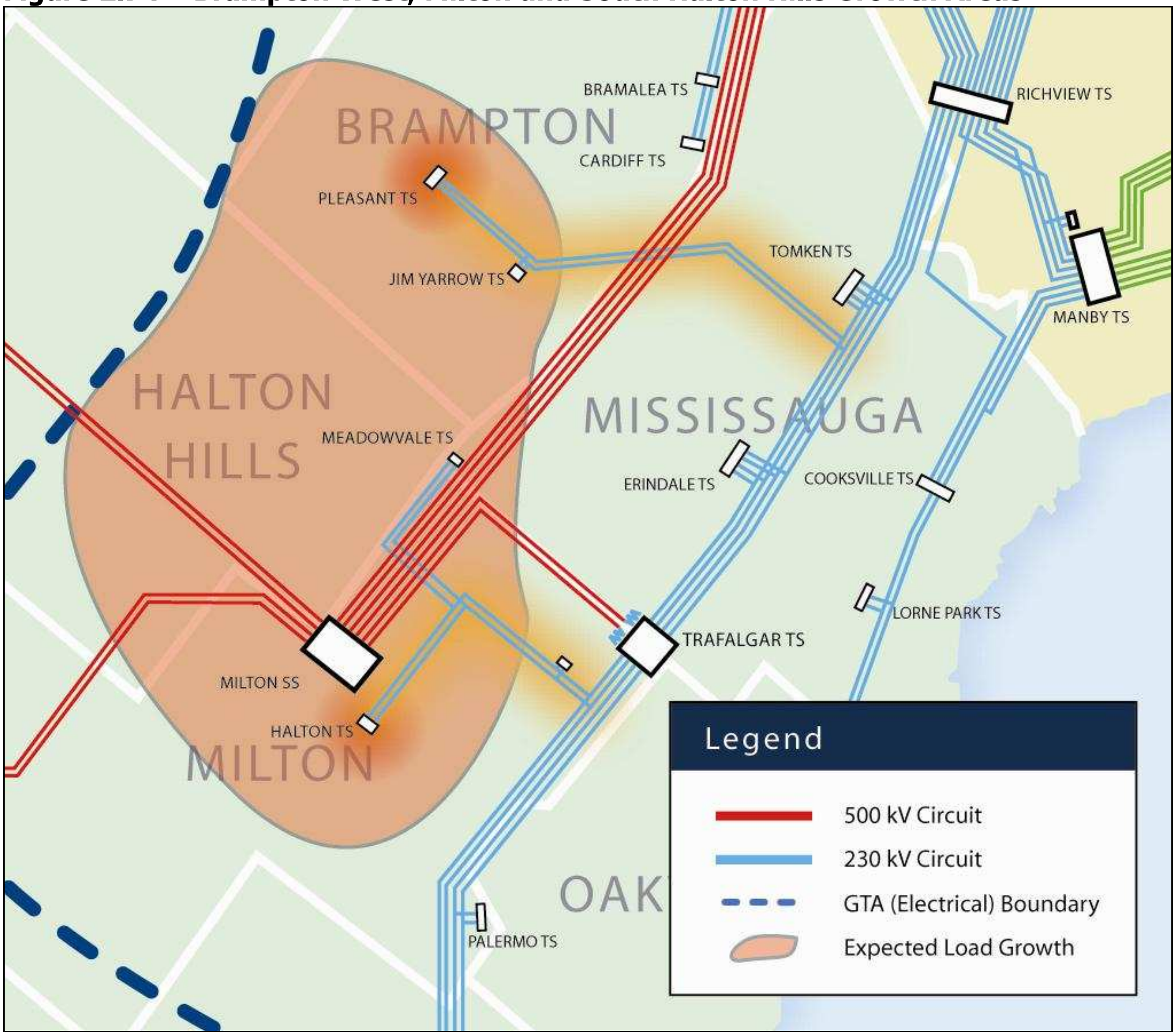
Figure 2.73 – Hurontario Station and Line Extensions



Source: IESO and OPA

While the Hurontario station and line work address the immediate and near-term needs, additional transmission facilities will be required to meet medium- and long-term needs. The 230 kV circuits supplying the western Brampton, Halton Hills and Milton areas will reach capacity by 2014. With the urban boundaries expanding and forecasts for significant development, the load growth in these areas is the highest in the province. For example, the Halton station load has been growing at nearly 10 percent per year over the last three years and is expected to continue over the next five years. Over the next 10 years, the Halton station load growth is projected at six percent per year. Halton Region projects the population growth in the Town of Milton to be 60 percent over the next 10 years. The City of Brampton projects a population growth of 35 percent over the next 10 years.

Figure 2.74 – Brampton West, Milton and South Halton Hills Growth Areas

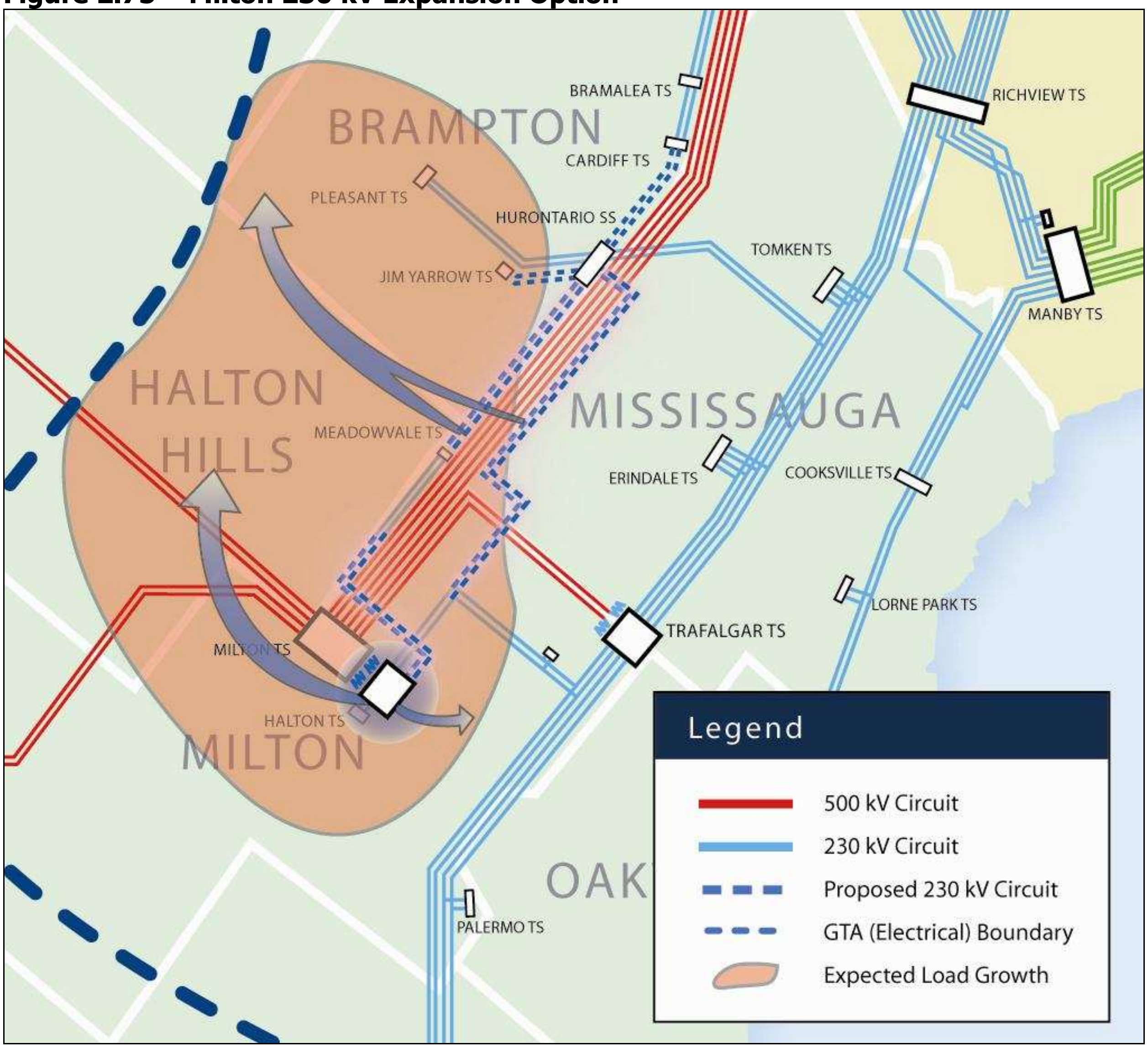


Source: IESO and OPA

As Figure 2.74 shows, there is limited transmission to supply the expanding areas of western Brampton, southern Halton Hills and Milton. The 230 kV line currently supplying the Jim Yarrow and Pleasant stations will require reinforcement by 2013 to address the growing loads on the existing stations. Within the next five years another load station is expected to connect to the 230 kV circuits from Trafalgar that currently supply the Trafalgar, Halton and Meadowvale load stations. Additional load stations cannot be accommodated on any of these circuits without exceeding the IESO criterion for the total load permissible on a double-circuit line section. In the medium-term and beyond, new transmission facilities will be required to supply new load stations in these expanding areas.

There is room on the Highway 407 transmission corridor to accommodate two new 230 kV double-circuit lines from the Milton to Hurontario station. This makes the Milton station an ideal location for a new supply point into the GTA. Expansion at the Milton station would include a pair of 500/230 kV transformers and a 230 kV switchyard to connect the new 230 kV circuits. The new 230 kV circuits would provide additional capability to connect new load stations along the 407 corridor. These new circuits could also re-supply the Jim Yarrow and Pleasant load stations and provide relief for the Claireville and Trafalgar 500/230 kV transformers. Figure 2.75 conceptually shows the new 230 kV lines along the existing 500 kV corridor from the Milton station.

Figure 2.75 – Milton 230 kV Expansion Option



Source: IESO and OPA

One of the 230 kV circuits would be an eight km extension of the existing 230 kV circuit between the Halton and Meadowvale load stations to the Hurontario station. The Halton load station could remain part of this new circuit, or could be terminated directly into the Milton 230 kV switchyard to free up more line capacity. The second 230 kV circuit would run the entire length of approximately 18 km from Milton to Hurontario. In the longer term, as development expands further north, new 230 kV circuit spurs that run north through Halton Hills or western Brampton areas will be required. New north-south transmission right-of-ways will be needed. The OPA will be working with municipal planning agencies to ensure that transmission use is considered when the municipalities are planning multiuse corridors for long-term development. Once the 230 kV switchyard at Milton is developed, the 230 kV transmission lines can be developed in stages as the need grows.

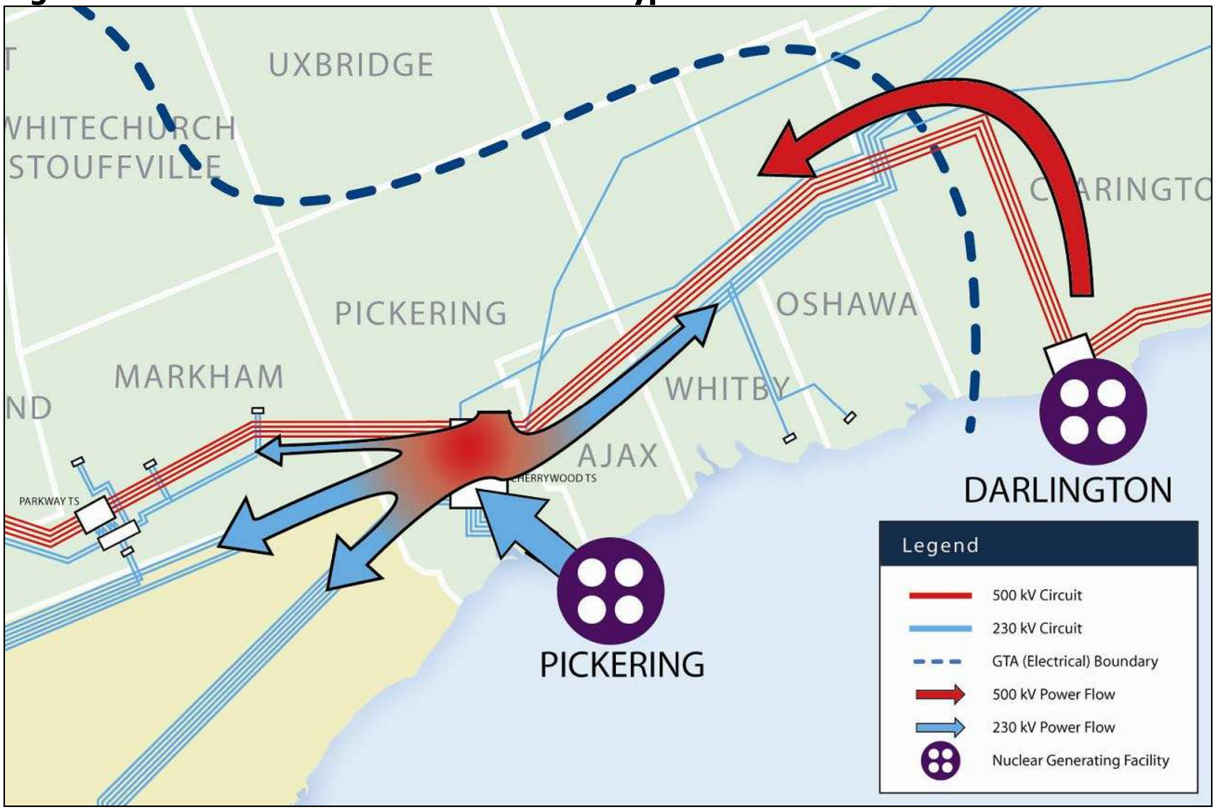
While the primary need for the Milton 230 kV expansion is supply capacity for the western Brampton, Halton Hills and Milton areas, this transmission development will also increase the overall GTA supply capacity by another 1,500 MW, relieve the Claireville 500/230 kV transformers, improve the GTA area voltage and further diversify the 500/230 kV supply points.

By 2015, the 230 kV circuits on the Trafalgar to Richview corridor will reach capacity. The Milton expansion and the transfer of the Jim Yarrow and Pleasant loads will significantly reduce the loading on these circuits. However, if more capacity is required to accommodate additional load stations and higher transfers from generation or imports from southwestern Ontario, a new double-circuit 230 kV line of approximately eight km would be required from the Trafalgar station to connect to the 230 kV circuits, which supply the Oakville load station. Right-of-way space for such a line is available. A transmission corridor route has been identified in the Parkway Belt West Plan. As mentioned previously, this transmission line would also address the Richview to Manby supply capacity issue. Consideration could be given to advancing the Trafalgar to Oakville line in lieu of rebuilding the 115 kV tower line between Richview and Manby.

GTA East

The Cherrywood station is the 500 kV and 230 kV hub in the GTA East. There are four 500 kV circuits that connect Cherrywood to the Bowmanville stations. The Darlington nuclear generation station delivers power into the 500 kV system at Bowmanville. There are four 500 kV circuits that connect Cherrywood to the Claireville station. At Cherrywood, the four 500/230 kV transformers and the generation at Pickering deliver power into the 230 kV system. Six 230 kV circuits run east to the Peterborough, Belleville and Ottawa areas. These circuits deliver the power to the GTA East and Peterborough area loads. West from Cherrywood, there are twelve 230 kV circuits which supply the City of Toronto and Markham areas. Six of these 230 kV circuits connect to the Leaside station to supply the eastern, central and downtown areas of Toronto. Two 230 kV circuits connect to the Parkway station to supply the Markham areas. Four 230 kV circuits connect to Richview to supply the northern parts of Scarborough, North York and Etobicoke.

Figure 2.76 – GTA East Transmission and Typical Flows

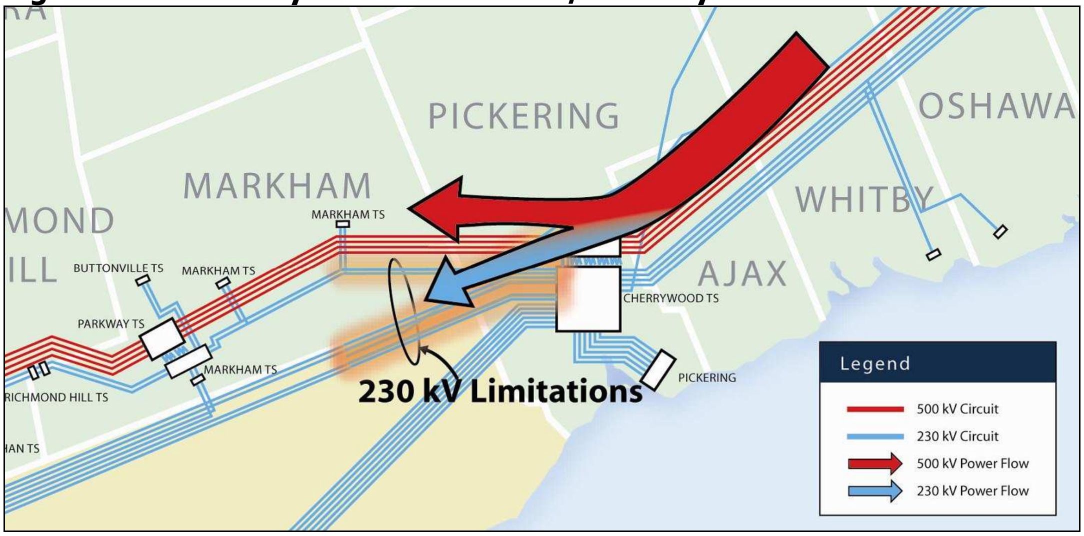


Source: IESO and OPA

The key events that would impact the GTA East transmission system are changes to major generation in GTA East and in eastern Ontario. This could include such developments as new wind generation, new generation at Darlington, retirement of Pickering generation or new high-capacity interconnections with Quebec or New York.

The limitations for incorporating new power sources east of Cherrywood are the 230 kV circuits from Cherrywood to Parkway and Richview. The existing system can accommodate about 1,500 MW of additional generation or imports from eastern Ontario before the capabilities of these 230 kV circuits are exceeded. Improvements to the Cherrywood to Parkway and Richview 230 kV circuits for higher transfer levels are limited since these circuits are already using fairly large conductors. Special high-capacity conductors and extensive tower reinforcements may be necessary to provide any significant line capacity improvement. Other alternatives could include installing in-line breakers to split the 230 kV circuits when there are overloads or to split the circuits in a permanent manner. When the circuits are split, sections of the circuits would be supplied radially with no "through" flows between Cherrywood, Parkway or Richview. The option to split the 230 kV circuits is made more viable by the work currently underway to unbundle the Cherrywood to Claireville 500 kV circuits. Presently the four circuits are bundled in pairs and connected as though they were two "super" circuits. This work will improve operational flexibility and transfer capability on these 500 kV circuits.

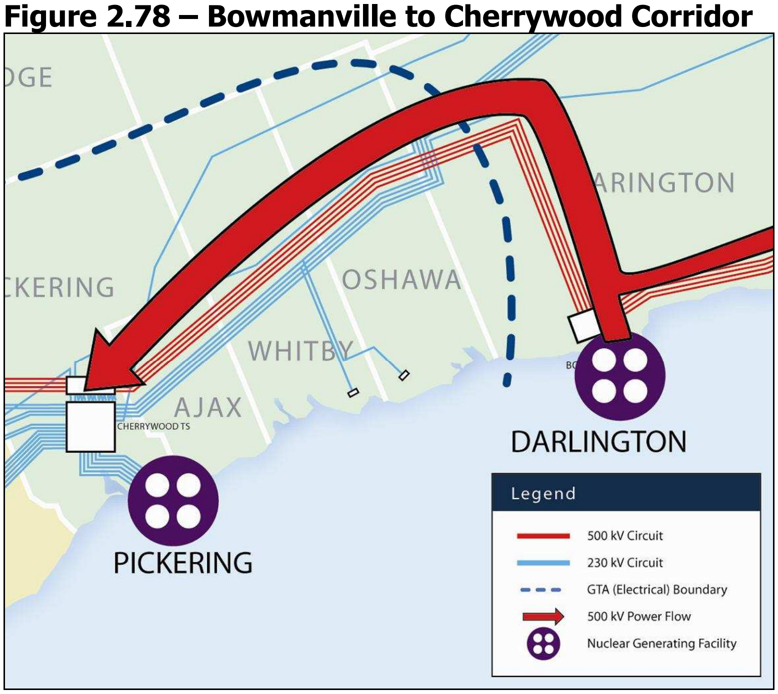
Figure 2.77 – Cherrywood to Richview/Parkway 230 kV Limitations



Source: IESO and OPA

The next set of limiting transmission facilities are the four 500 kV circuits on the Bowmanville to Cherrywood corridor. These 500 kV circuits have a transfer capability of about 6,500 MW. The output from Darlington takes up 3,600 MW of this capacity. Currently under high import conditions from eastern Ontario, 1,000 MW to 1,400 MW of power can flow on this corridor, leaving 1,500 to 1,900 MW of remaining transfer capability.

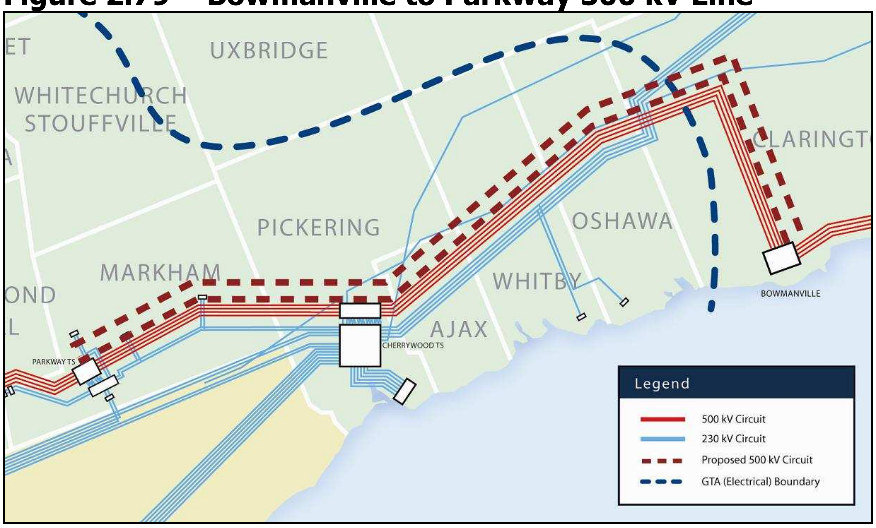
Figure 2.78 – Bowmanville to Cherrywood Corridor



Source: IESO and OPA

To accommodate additional power flows of 2,000 MW or more, reinforcing the Bowmanville to Cherrywood corridor with additional 500 kV circuits will be required. The existing corridor permits another double-circuit 500 kV line, 65 km in length, to be constructed from Bowmanville to Cherrywood and from Cherrywood to Parkway. The need for the Cherrywood to Parkway section depends on the level of additional power flows. There is a limited amount of power that can be delivered to the 230 kV systems at Cherrywood. Also, as noted earlier, it is desirable to reduce the concentration of supply facilities at Cherrywood. Both concerns could be addressed by extending the new 500 kV line to Parkway and bypassing Cherrywood altogether. This provides an "express" route from Bowmanville directly into Parkway. To absorb the extra power flowing into Parkway, additional 500/230 kV transformation and 230 kV reconfiguration facilities would be required to supply more load from Parkway. Options to transfer more loads to Parkway could include the third supply option from Parkway to supply downtown Toronto loads, and the extension of 230 kV circuits to pick up the Vaughan load stations or other York Region loads currently supplied from Claireville.

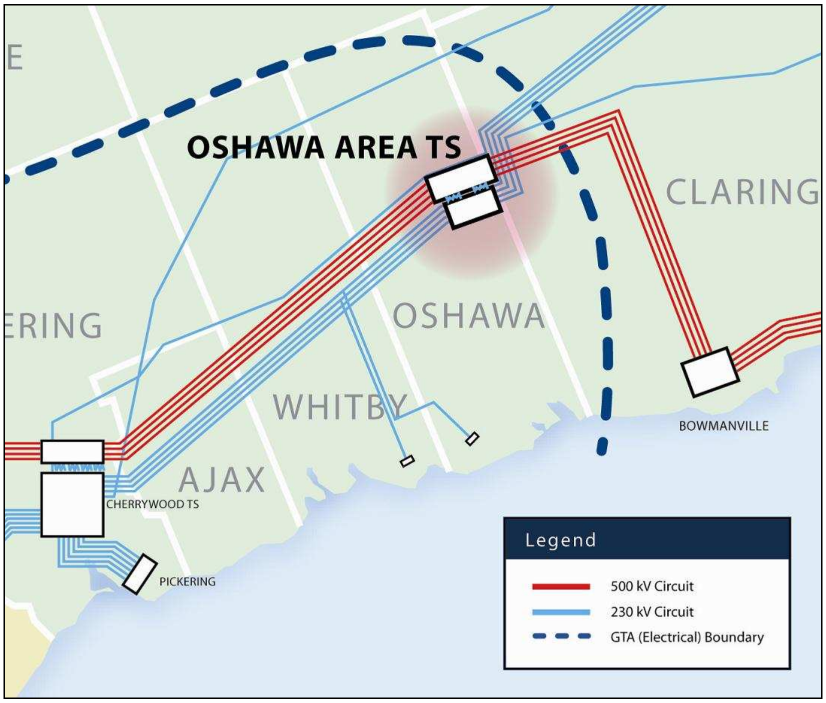
Figure 2.79 – Bowmanville to Parkway 500 kV Line



Source: IESO and OPA

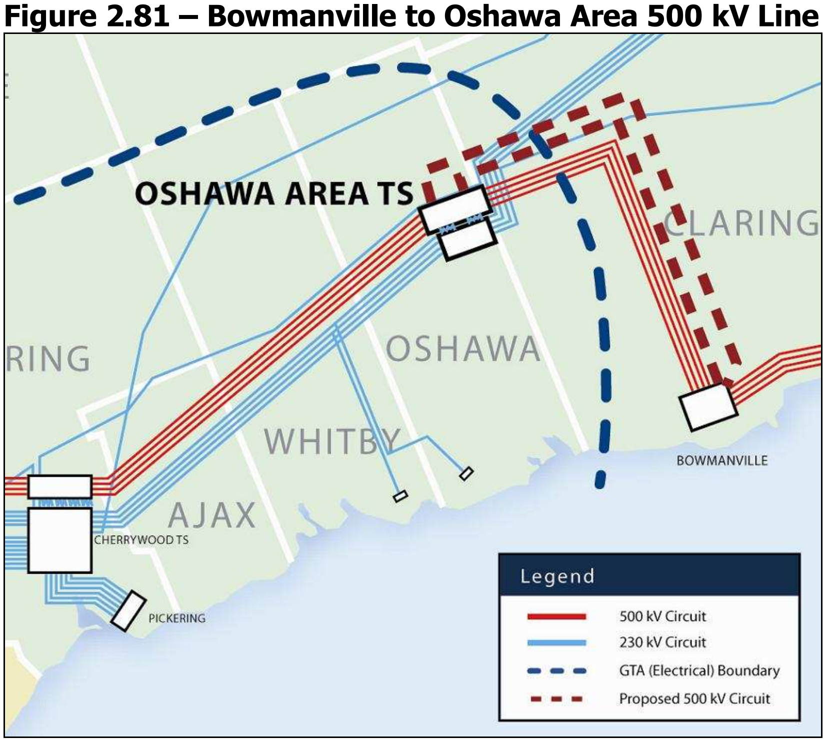
If additional power flows east of the GTA are less than 2,700 MW, an alternative to building the new 500 kV circuit to Parkway is to establish a new 500/230 kV station in the Oshawa area, similar to the Parkway station. A site was established by the former Ontario Hydro for such a purpose. This site, referred to as the Oshawa Area station, is located at the intersection of the Bowmanville to Cherrywood 500 kV circuits and the five 230 kV circuits from Cherrywood to eastern Ontario. The Oshawa Area station is shown in Figure 2.80. The loads in the GTA East would then be supplied from the Oshawa Area station rather than the Cherrywood station. As shown in Figure 2.81, a new 500 kV line only 20 km in length would need to be built from Bowmanville. This connection to the Oshawa Area station would reduce the flows on the existing 500 kV lines to Cherrywood by more than 1,000 MW.

Figure 2.80 – Oshawa Area Station



Source: IESO and OPA

Figure 2.81 – Bowmanville to Oshawa Area 500 kV Line



Source: IESO and OPA

Retirement of existing generation located in the GTA will affect the transmission system in GTA East. In particular, a decision not to refurbish Pickering B nuclear units would have significant impacts. Such a decision would remove up to 2,000 MW of internal generation from the GTA. The Cherrywood 500/230 kV transformers would be inadequate to provide the necessary supply capacity to the 230 kV system. The loss of this generation would also require the Oshawa Area station to be built. The Oshawa Area station would provide a new 500/230 kV supply point into the GTA East 230 kV system. The new supply point would further diversify the supply risk at Cherrywood. It would also reduce the reactive power demand at Cherrywood and provide additional voltage support to the 230 kV system. This would help minimize the additional reactive power needed when the Pickering B units are removed. The Parkway third supply option for downtown Toronto would also help to reduce the loading on the Cherrywood 500/230 kV transformers and the need for reactive power. The combination of the Parkway third supply option and the Oshawa Area station could address the Pickering B retirement from a transmission supply perspective.

A refurbishment program for the Pickering B units that involves outages of more than two units for extended periods would also have significant impacts on the transmission system, in particular, the Cherrywood 500/230 kV transformers. In such cases, reconfigurations of the 230 kV system to reduce the loading at Cherrywood or temporary generators may be required. Alternatively, if the Oshawa Area station is required for new generation or area supply, it could be advanced to make it available during the critical refurbishment periods. The Oshawa Area station could substantially mitigate impacts arising from delays in the refurbishment program.

With regard to the GTA East area supply capacity, no significant issues are observed into the medium-term period. The existing 230 kV circuits emanating east from Cherrywood have adequate capacity to meet the near- to medium-term needs. To permit more stations to connect to the 230 kV circuits in the longer term, development of the Oshawa Area station may be required. This would permit the GTA East loads to be supplied from two points and would reduce significantly the circuit loadings from the Cherrywood end.

In summary, the Oshawa Area station may be a medium-term development to address the retirement, and possibly the refurbishment, of the Pickering B units or a long-term development for generation incorporation or area load supply.

3. Analysis of Environmental Impact and Alternatives

Under paragraph 8 of Section 2(1) of the IPSP regulation (Ontario Regulation 424/04, as amended), electricity projects that trigger an individual environmental assessment under Ontario's *Environmental Assessment Act* within five years of the approval of the IPSP require additional analysis. For these projects, the OPA is required to provide a "sound rationale," as well as "an analysis of the impact of the electricity project on the environment, and an analysis of the impact on the environment of a reasonable range of alternatives to the project."

A number of prospective projects meet this requirement, but only a portion of these projects will likely be recommended for approval in the first five years following the IPSP's approval. Under Ontario Regulation 116/01, as noted in Table 3.1, the projects that meet these criteria are 230 kV transmission lines longer than 50 km, 500 kV transmission lines that are longer than 2 km, and waterpower projects that are equal to or greater than 200 MW. There are a number of transmission projects and no waterpower projects that meet the criteria in regulation 116/01, but not all will meet the five-year criterion in regulation 424/04.

Table 3.1 – Electricity Projects Requiring Individual Environmental Assessments

Electricity Project Type	Conditions for Individual Assessment
Transmission lines	> 115 kV and < 500 kV and > 50 km ≥ 500 kV > 2 km
Transformer stations	> 500 kV
Hydroelectric facilities	≥ 200 MW
Oil facilities	≥ 5 MW
Coal facilities	All
Municipal solid waste	Incinerating MSW from ≥ 1,500 persons domestic waste or > 100 tonnes of waste per day
Liquid industrial or hazardous waste	Sites receiving and incinerating off-site generated waste

Source: Ontario Regulation 116/01 and Ministry of Environment, Guide to Environmental Assessment Requirements for Electricity Projects (March 2001). NB: Requests can be made for other electricity projects to be subject to Individual Environmental Assessments.

Notably, nuclear projects are outside the scope of the requirements set out in the IPSP regulation. Nuclear projects are regulated by the Canadian Nuclear Safety Commission and subject to environmental assessment under the *Canadian Environmental Assessment Act*. Ontario Power Generation and Bruce Power are initiating their own processes, for refurbishment or new-build nuclear.

We have retained Hardy Stevenson and Associates Limited to complete the project-level analysis of prospective projects meeting the requirements of regulation 424/04.

3.1 Environmental Analysis of Electricity Projects

In this section, we introduce the analysis of electricity projects as required under the IPSP regulation. While the impact of the prospective projects on the environment is addressed in this section, the rationale for and alternatives to each of the projects is addressed differently. As all of the projects are transmission projects for system reinforcement or incorporation of new renewable resources, each project being contemplated helps meet the government's policy commitments outlined in the Minister's June 13, 2006 directive. This, therefore, is the sound rationale for these projects. The alternatives to the projects include additional conservation and demand management (CDM) or other forms of generation.

In our assessment of demand and supply resources in Ontario, we have found there is no ability to meet the renewable resources target (15,700 MW) without investments in transmission. The feasible renewable resource potential is primarily located in northern and rural Ontario, while the demand is concentrated in the urban south. Moreover, there is little scope to reduce the need for this renewable resource capacity through local generation, conservation and demand management (CDM) or additional conventional generation resources in the south.

The projects that have been addressed in this paper are prospective and are required over the life of the plan, not only in the first five years. The first IPSP will recommend fewer projects than will appear in the following section and in Appendix 2 of this paper. This means that in subsequent IPSPs, as more knowledge is gained on local renewable resource options, such as bioenergy, there may be alternatives for meeting the renewable energy targets with less new or upgraded transmission.

The potential environmental effects of the projects are evaluated using two methods: a project-level environmental assessment and a strategic environmental assessment (SEA). The project-level environmental analysis is conducted by Hardy Stevenson at a "corridor" level of detail. The discussions of environmental and socio-economic effects of the electricity projects and their alternatives are qualitative and descriptive, but are supported by a "desk top" analysis. The analysis includes quantitative data where it is available and is supported by geographic information system (GIS) mapping. Some of the projects under review have been the subject of previous environmental assessments. While field work is not considered within the scope of the IPSP work, in the past, members of Hardy Stevenson's project team have completed environmental assessment-level field work for most of the projects under consideration.

The SEA approach applied by Hardy Stevenson draws on primary and secondary data sources, socio-economic and environmental data derived from GIS analysis and information from existing environmental assessment studies. SEA evaluates projects, as seen together, at a broader level of detail than on the project-level analysis. Three core SEA questions are considered: (1) will non-transmission projects (such as highways or pipelines) occur in the same time and space as the proposed transmission project and result in cumulative effects? (2) are other transmission projects expected to occur coincident with the subject transmission project and have overlapping effects? (3) when all transmission projects are seen together, will there be broad effects?

As stated previously, the analysis is undertaken at a corridor level of detail. This is distinct from a routing study, as corridors are generally scoped more broadly to allow for the identification of route alternatives and variations resulting of environmental, geo-physical or socio-economic features. Several of the prospective projects in this paper utilize existing rights of way and transect developed areas. In these cases, the corridors are narrow, typically 500 metres outside either edge of an existing right-of-way. For new lines, such as the Ontario Manitoba interconnection, the assessed corridors (study areas) are necessarily larger.

The factors by which projects are evaluated are adapted from standard and SEA evaluation methods, including Ontario's environmental assessment process and SEA methods commonly applied to master plans. The required parameters and components of this methodology are flexible and subject to adjustment, depending on the purpose of the assessment. The evaluation factors considered for SEA include the following.

- type, location and magnitude of potential effects
- cumulative construction and operations effects
- potential level of public concern
- risks from natural hazards (such as tornadoes and ice storms)
- mitigation and compensation and residual effects.

A "do nothing" option was considered for all projects. The evaluation factors that are considered for each project are listed in summary form in Table 3.2.

Table 3.2 – Evaluation Factors for Large Electricity Projects

Factors	Indicators
Socio-economic	Land-use, First Nations interests, settlement features
Agricultural	Soils
Aquatic	Wetlands, lakes and rivers
Terrestrial	Habitat
Forestry	Forested areas, woodlots

Source: Hardy Stevenson

Hardy Stevenson is also assessing whether the prospective IPSP electricity projects, individually and combined, represent a sustainable approach to electricity planning. The assessment investigates the environmental and socio-economic features and implications of transmission projects that may be recommended in the IPSP. The list of projects assessed by Hardy Stevenson is larger than the set that will likely be recommended by the plan.

An important principle guiding the assessment is avoidance of impacts to ecologically sensitive areas. Wherever possible, capacity expansion will leverage existing corridors or routes that can be redeveloped or upgraded and give preference to new transmission projects that utilize existing right-of-ways. This will minimize land use requirements.

3.2 Project Listing

Hardy Stevenson has provided a preliminary analysis of 12 prospective transmission projects. The projects vary considerably in size and occur in both rural and urban areas in northern and southern Ontario. These projects are listed in Table 3.3. The preliminary analysis results are presented in Appendix 2.

Table 3.3 – Transmission Projects Triggering Individual Environmental Assessments

Project	Description
Manitoba Transmission Interconnection	500 kV east-west transmission from Nelson River hydro-electric projects in Manitoba to Thunder Bay area, with further transmission system reinforcement to Sudbury
Little Jackfish Hydro and Lake Nipigon Wind Development	230 kV transmission from Nipigon station to Little Jackfish for hydroelectric and east of Lake Nipigon wind development
Lake Superior East Wind Development	230 kV transmission from Sault Ste. Marie to Mackay (replace existing 130 kV) and 500 kV from Sault Ste. Marie to Mississagi
Sudbury West Transmission Reinforcement	230 kV transmission redevelopment from Hanmer station (Sudbury) to Mississagi station (east of Sault Ste. Marie)
Manitoulin Island Wind Development	Rebuild 115 kV transmission from Espanola to Little Current to 230 kV and add new 230 kV transmission from Little Current to Wikwemikong Unceded Reserve
Moose Basin Hydro Development	500 kV transmission from Moose Basin to Sudbury
North-South Transmission Reinforcement	500 kV transmission from Sudbury to the Toronto area
Barrie South Transmission Reinforcement	500 kV transmission from Essa station (west of Barrie) to Claireville station (Vaughan)
Parry Sound Wind Development	230 kV transmission from Parry Sound station to the Byng Inlet area
Bruce – Greater Toronto Area (GTA) Transmission Reinforcement	500 kV transmission from Bruce Power nuclear generating station to the GTA
Bruce Peninsula Wind Development	230 kV transmission from Owen Sound station to south of Tobermory area
Darlington B Incorporation	500 kV transmission from Bowmanville SS to an new Oshawa area station

Source: OPA

4. Transmission Development Proposals to Meet Policy Objectives in the Government Directive

This paper has provided an overview of the transmission system in Ontario and a detailed discussion of the issues, needs and solutions for the eight subsystems defined. It is important to remember that the solutions presented for addressing the identified needs in this paper are a survey of potential options. They are not recommendations, unless as noted or as appropriate, on whether any of the options should be implemented or on the sequencing of the options. Transmission is an enabler to facilitate resource development and maintain system reliability and efficiency. Its development must be integrated with the overall demand and supply plan. The companion integration discussion paper (#7) will discuss how, what and when transmission is needed in the context of overall integrated planning of resources and transmission in Ontario for the next 20 years.

The ministerial directive contains a number of policy objectives that provide directions to the OPA in formulating the transmission development plan in the IPSP. While the specific transmission development elements of the IPSP will be discussed more fully in the companion discussion paper, here are some of the proposed approaches to meet the transmission-related policy objectives (highlighted in italics below).

Enabling the achievement of the supply mix goals

- Identify restrictions or obstacles to the integration of the resources proposed in the IPSP and provide solutions to address them in a timely manner. The lead time required for implementing the transmission solution is a major consideration.
- Consider the need to connect these resources to the power network, and the ability to transfer the power with minimum restrictions to customers connected to the network and maintain system reliability and performance.
- Evaluate the choice of location and timing of development for some resources, such as wind generation. Decisions will be influenced by transmission availability, implementation lead time and cost. Integration of the transmission component in the evaluation of the specific options is essential.
- Provide for an early start in seeking regulatory approvals, conducting environmental assessment of routes and sites required for the transmission solutions, and the necessary project development work. This allows for a better coordination between the resource and transmission implementation lead times.

Facilitate the development and use of renewable energy resources

- The transmission plan will advance the concept of developing transmission (enabler connections) for dedicated renewable locations where there is significant development potential remote from the power grid and where there is economy of scale in coordinating their development.

- These resources will be difficult to develop without a proactive and coordinated approach to ensure transmission is available in a timely fashion with the resources.
- The economic development of renewable energy resources, in particular, those in remote locations of the province, will require, to the extent possible, the full use of transmission infrastructure that is dedicated for their incorporation into the power network. The timing and capacity of transmission provided will impact on where, how much and when different groups of renewable resources will be developed.

Promote system efficiency and congestion reduction

- The transmission plan will consider the impact of changes to regional demand and resources on the bulk transmission paths, and identify and address potential congestion points on the transmission network. In general, the aim of the transmission development plan is to minimize congestion and the need to frequently curtail low cost and clean energy resources because of transmission constraints.
- The aspects of transmission losses will be incorporated in the evaluation of the cost of resources in different locations of the province. The proposed transmission solution will considered appropriate equipment and system design, such as voltage ratings and technology, to minimize losses within the industry practices.

Facilitate the integration of new supply, all in a manner consistent with the need to cost effectively maintain system reliability

- In integrating the new resources, the individual elements of the proposed transmission development plan will be designed and conformed to accepted reliability criteria and standards to maintain an adequate level of system reliability.
- Appropriate configurations, routings and technologies will be considered in terms of performance, cost and environmental/land use impact to arrive at a preferred solution.
- Technologies and applications that are new to Ontario, but are used elsewhere, such as series capacitors and static VAR compensators, will be included in the scope of solutions.

Pursue applications that allow high efficiency and high value use of the natural gas fuel

- For local area reliability needs, an integrated planning approach will be employed. As such, conservation and demand management options, generation options and transmission and distribution options will all be considered in developing the preferred solution. In many cases there is a synergy between system supply adequacy need and local reliability need. This provides the opportunities to develop gas-fired generation at appropriate locations on the network to effectively address both needs.
- The proposed use of gas-fired generation to relieve specific local area reliability needs will consider the cost and availability of gas supply, demand diversity on the gas supply and general community acceptance.

Replacement of coal-fired generation and necessary transmission infrastructure

- The proposed transmission development plan has identified specific system needs related to the shut down of the coal-fired generating units. Solutions have been proposed.

In the companion integration discussion paper (#7), the specific elements of the transmission development plan will support resource development in an integrated manner consistent with the strategic approaches discussed above.

Appendix 1: Power System Concepts, Terms and Special Facilities

A brief description of the power system concepts, terms and special facilities covered in the IPSP Transmission Discussion paper is provided below:

Power System Planning and Design Criteria used in the planning of the transmission system in the IPSP is based on the rules, criteria, standards, and guidelines established by the IESO, Northeast Power Coordinating Council (NPCC), and North American Electric Reliability Council (NERC). Reliability standards in Ontario are mandatory and enforced through the IESO administered Market Rules that govern the operation of the electricity marketplace and bulk power system. The IESO's Ontario Transmission Assessment Criteria document sets out the technical criteria for transmission planning of the IESO-controlled grid. The NPCC criteria and principles for bulk power system planning are mainly provided in their Document A-2 (Basic Criteria for Design and Operation of Interconnected Power Systems) and Document A-5 (Bulk Power System Protection Criteria).

Power system planning and analysis uses a deterministic contingency-based assessment to evaluate the adequacy and security of the bulk power system. The power system must be planned with sufficient capability to withstand the loss of elements resulting from specified, representative, and reasonably foreseeable contingencies (i.e., disturbances) at projected customer demand and anticipated power transfer levels. When these contingencies occur, they should not result in any criteria violations, or the loss or unintentional separation of a major portion of the system. The power system must be designed to keep voltages, line and equipment loading within applicable limits following these contingencies. The contingencies to be tested are specified in the NPCC Document A-2 and the IESO Ontario Transmission Assessment Criteria.

Power System Stability refers to the ability of the system to maintain a stable operating state following a disturbance or a change to the power system.

The control and operation of power systems is complex. All generating machines that produce electricity are synchronized with each other so that they generate power in a coordinated manner. The power that they produce must always equal the load being consumed by users and this balance must be maintained on a near instantaneous basis throughout the entire interconnected system.

Occasionally, disturbances occur that can disrupt this equilibrium. The system is designed so that this equilibrium and a stable operating state must be established for a recognized set of disturbances. A stable operating state means that generating machines stay in synchronism and adequate voltages are maintained so that uncontrolled disconnection of power system elements (e.g., generators, lines, loads, etc.) does not occur.

Transient stability and voltage stability are two major sub-classes of power system stability issues. Transient stability is generally associated with large disturbances. Transient instability results in the disconnection of generators, typically within seconds of the disturbance. Voltage stability refers to the ability to maintain stable operating voltages for small or large perturbations on the power system. Voltage instability results in the uncontrolled decline of voltages (or "voltage collapse") leading to the disconnection of power system elements. Voltage instability can develop in seconds to several minutes and can result from disturbances, excessive power transfers or high system loadings. Transient instability or voltage instability can lead to major disruptions to the power system.

Reactive Power – The NERC Glossary of Terms, May 6, 2006, defines reactive power as: "The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar)." In more general terms, reactive power provides voltage support for the transmission system. Voltage is equivalent to pressure, like the pressure required to keep water flowing from your garden hose. Reactive power is one way to maintain or support voltage, allowing power to be transmitted.

Generation Rejection or GR is automatic detection of transmission line outages and immediate disconnection of generating units in a pre-designed, controlled manner following such outages to maintain system stability and safe equipment loading. Generation is typically disconnected for a short period of time. A generation rejection scheme is one type of the broader class of special protection schemes (SPS). Ontario deploys these throughout the province, and has deployed GR at Bruce for many years. It operated infrequently at Bruce.

Series Compensation is the use of a technology which inserts capacitors in series with the transmission circuit in order to reduce its "effective electrical length" and provide reactive power support under high power transfers conditions. percent compensation is the resulting reduction in the effective line length, i.e., 30 percent compensation would be to reduce the effective line length by 30 percent.

Synchronous Condensers are generators that are operated to produce reactive power only. Thus, they do not require the turbine and prime mover portion of generating facilities. They will require all the equipment associated with the generator operation, including the excitation and voltage regulator systems, and the transformer, bus and switching facilities associated with connection to the transmission system.

Static VAR Compensators (SVC) uses power electronic technology in combination with conventional capacitors and reactors to provide adjustable reactive power. The ability of this equipment to act very rapidly to changing system conditions and handle high voltage and high currents makes these devices suitable for reactive power control.

High voltage Direct Current (HVDC) transmission facilities use power electronics to convert power from an alternating current (AC) form to a direct current (DC) form. Most of the electricity transmitted on the bulk power system and used in homes and businesses are in AC form. The advantages of DC transmission is that power can be transmitted over long distances with lower losses than AC transmission. The facilities that convert the power from AC to DC at the sending end and DC back to AC at the receiving end are known as converters. Converters provide full control of the amount of power that can be transmitted and power flow levels can be adjusted in a fraction of a second. Another application of the converters is to install them "back-to-back" with no transmission line in between. This allows two transmission systems to be connected in a "non-synchronized" (or asynchronous) manner. Each system can be operated completely independently, even at different frequencies. The Hydro-Quebec system is connected to its neighbours in both Canada and the U.S. in an asynchronous manner with HVDC facilities.

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Appendix 2: Project Assessments - Preliminary Results

Manitoba Transmission Interconnection

Project Description: The current 230 kV transmission lines that transport electricity from northwestern Ontario to other regions of the province are limited to about 350 MW in capacity. About 2,000 MW of wind and 800 MW of hydroelectric capacity have been identified in northwestern Ontario, in addition to the possibility for up to 1,250 MW of hydroelectric import capacity from the Nelson River system in Manitoba. Major reinforcement of the east-west tie capacity would be required to be able to connect even a portion of these resources to the Ontario system. To connect the 2,800 MW of domestic renewables in northwestern Ontario, the east-west tie would need to be strengthened by constructing a 500 kV transmission line. The prospective line would be constructed from somewhere along the Manitoba border to Sudbury.

This project assumes that Manitoba Hydro will develop a major new generating station on the Nelson River and that significant wind and hydroelectric generation will be developed in northwestern Ontario.

Summary of Environmental and Socio-economic Analysis: This project has been considered in two separate study areas due to the line's length. The first study area extends from the Manitoba border to the Thunder Bay area and includes both sides of Lake Nipigon. The second study area is from Thunder Bay to Sudbury. The total study area has been selected to be large enough to enable the selection of a suitable range of options for this project. This review focuses on the Ontario portion of the Manitoba-Ontario interconnection.

The study areas include some larger and smaller settlement areas from Nipigon to Sudbury portion, as well as a variety of Treaty areas, including Treaty 3, Robinson-Huron and Robinson-Superior Treaty areas. The Nishnawbe-Aski Nation has five tribal councils that could be affected by this project.

First Nations communities in northwestern Ontario are seeking alternative revenue sources, which could come from fees or rental arrangements for transmission projects crossing their lands, through shared ownership, or from developing renewable energy projects. In addition, virtually all of the remote communities in northwestern Ontario produce electricity using diesel generators, and there is a desire among these communities to connect to the provincial grid. Connecting to the grid would eliminate the environmental and health impacts associated with the combustion of diesel fuel near populations and reduce the reliance on transporting fuel. However, it may be difficult to overcome technical and cost challenges associated with such connections to the bulk electricity system.

Other socio-economic concerns relating to this project include increased access to remote unspoiled areas of northwestern Ontario and effects on traditional land-uses significant to First

Nations people. Subsequent environmental assessment studies should identify traditional use areas.

In terms of environmental impacts, GIS data are not available for much of the study area. It is known that the area is comprised of boreal and some lowland areas. Flora and fauna are those characteristic of the boreal forest. There is a large woodland caribou range that may be affected west of Lake Nipigon, and a large number of parks and protected areas are located within both study areas.

Various natural features and signature sites will require consideration in subsequent environmental assessment studies, including the Lake Superior heritage coast, Lake Nipigon basin and the Nagagamisis Central Plateau complex, a waterway system park located 75 km southwest of Hearst. Some mines are active in the study areas, including a De Beers diamond exploration site between the First Nations communities of Kasabonika, Wawakapewin and Kitchenuhmaykoosib.

Little Jackfish Hydro and East Nipigon Wind Development

Project Description: The development of new 230 kV transmission facilities is required to connect the proposed Little Jackfish generating station at the north end of Lake Nipigon and wind developments east of Lake Nipigon to the bulk transmission system at the existing 230 kV line south of Lake Nipigon. The proposed Little Jackfish station is 132 MW and the potential wind developments could be up to 300 MW of nameplate capacity.

The potential corridor follows the east side of Lake Nipigon from Little Jackfish to Beardmore and the east side of Lake Nipigon to Kama Bay. From Beardmore, this corridor follows the existing 115 kV line to Alexander station. The line length is 185 km.

Summary of Environmental and Socio-economic Analysis: The study area encompasses the proposed Little Jackfish hydroelectric development and existing transmission lines in the Lake Nipigon area, extending approximately 45 km to the east of Lake Nipigon. An environmental assessment was initiated for the Little Jackfish facility and associated transmission lines in the 1980s, but was withdrawn in 1999 prior to approval. The study area has been broadened to include areas east of Lake Nipigon that have future wind power potential.

Socio-economic and environmental characteristics of the area have been examined on several occasions. There are several major parks, as well as First Nations communities and municipalities. Highway 11 is located in the southern part of the study area. The CN rail line is located in the northern part. Four existing 115 kV right-of-ways and two 230 kV right-of-ways extend to the east and north of the Town of Nipigon.

There is no significant agricultural activity in the area due to poor soils. Socio-economically, the study area is generally characterized by resource extraction activities, including mining, forestry, commercial fishing and tourism. Other economic activities include services and retail activities. Hunting and fishing are common as subsistence and commercial activities. There is no active forestry in the area (as of 1989), but this may be subject to change.

The natural environment is characterized by the Canadian Shield. The northern half is rugged with bedrock at or near the surface, while the southern half has thick surface deposits of varied clays, silts and sands. Vegetation in the area is mainly boreal forest, with common species being black spruce, white spruce, balsam fir, jack pine, trembling aspen and white birch. In terms of fauna, the study area contains caribou and moose wintering grounds and raptor feeding habitats and is dominated by lakes and watercourses.

Lake Superior East Wind Development

Project Description: The project includes two segments: one double-circuit 230 kV transmission line segment following an existing 115 kV line and one 500 kV new line segment. The 230 kV segment extends from Great Lakes Power's (GLP) Third Line station (Sault Ste. Marie) to GLP's MacKay station (near Montreal River), and the new 500 kV line also follows the existing 230 kV lines, extending from GLP's Third Line station to Hydro One's Mississagi station. The rationale for this project is to collect wind power and pumped storage. The estimated distance for the line is 91 km for the first segment and 76 km for the second.

Summary of Environmental and Socio-economic Analysis: The study area is defined as 500 metres to either side of the existing right-of-way (expansion of current right-of-way). It is characterized by boreal forest and Canadian Shield with limited areas of agriculture in the vicinity of Sault Ste. Marie. Highway 17 and a rail corridor are located in this area. The transmission lines would cross the Garden River First Nation and settlement areas in and around Sault Ste. Marie. North of Great Lakes Power's Third Line station the right-of-way crosses the Batchewana River Provincial Park. As additional transmission capacity parallels the existing right-of-ways, most of the potential socio-economic and natural environmental effects are known. Additional analysis is required through the environmental assessment process.

Sudbury West Transmission Reinforcement

Project Description: The addition of new wind power capacity north of Sault Ste. Marie will utilize some of the transmission capacity between Sudbury and Algoma, but generation additions exceeding 200 MW to 300 MW in this area will result in the need to upgrade the 230 kV line between Hanmer station and Mississagi station. The Algoma to Sudbury transmission path has an eastbound transfer capability of about 700 MW, but a recent study of renewable generation identifies about 2,500 MW of wind located west of Sudbury, in the Algoma and Manitoulin Island areas. A prospective solution is to redevelop the existing 230 kV line from Hanmer to Mississagi to 500 kV.

Summary of Environmental and Socio-economic Analysis: An environmental assessment study has already been completed for the proposed line. The existing right-of-way is isolated and traverses several park areas. The 500 meter wide study area encompasses several remote and established settlements, such as Bayfield and Elliot Lake. At the eastern terminus, the area traverses an industrial land use area near Greater Sudbury. These are First Nations reserves; however, a number of First Nations communities south of the study area may have an interest in the project.

The majority of the lands are characterized by the Canadian Shield and boreal forest ecosystem. Some agricultural lands are located beyond either end of the area, near Hanmer station to the east and Bayfield to the west, but are not expected to be affected by this project. There are no major wetlands in the study area, but several national and provincial parks are in close proximity.

The original environmental assessment for this project was completed in the mid-1980s. It appears that the environmental conditions may not have changed significantly since that time, but further assessment work will be necessary if this is the case.

Manitoulin Island Wind Development

Project Description: About 400 MW of wind generation potential is on Manitoulin Island. Developing this potential will require significant reinforcement of the 115 kV transmission capacity currently supplying Manitoulin Island. It will require an upgrade to 230 kV from the Espanola station to Manitoulin station at Little Current. In addition, a new 230 kV line will need to be constructed from the Manitoulin station, passing through the Manitowaning area to the south end of the Wikwemikong Unceded First Nation. The total distance is approximately 100 km. Two potential corridors have been identified. Corridor one provides for a route in the vicinity of Highway 6, and corridor two would require construction of a new transmission line along the western edge of the study area. It is assumed that a new transformer station would be required to accommodate either of these two options.

Summary of Environmental and Socio-economic Analysis: The study area follows the existing transmission right-of-way, from Espanola to Little Current on Manitoulin Island, then from Little Current to Manitowaning and from Manitowaning to the south end of Wikwemikong.

The area has diverse characteristics ranging from recreational uses to agriculture to tourism. Espanola is the largest urban centre, and smaller settlement areas include Little Current and Manitowaning. Three First Nations reserves occupy a substantial portion of the study area. The Highway 6 corridor is located in the centre of the study area. Parks, tourism and recreational resources create frequent use of Highway 6 in the summer. Several cultural heritage features have also been identified. These include: Assiginack Museum, Anishnabe Spiritual Centre and Great Spirit Circle Trail.

There are several quarries that vary greatly in size. One quarry is located near Highway 6 near Little Current and Espanola station and several others are located south of Little Current. Although much of the area is forested, no major forestry activity has been identified. From Little Current to the terminus in Wikwemikong, there are several areas of Class 2 and 3 agricultural lands.

The northern part of the study area is located in the Canadian Shield and the features are characteristic of the Niagara Escarpment. The southern portion of the area is mostly Niagara Escarpment and is composed of limestone. It has significant water bodies and lakes, including: Turtle Lake, Bass Lake and Pike Lake. Parts of the area are important migratory stops for waterfowl.

Overall, no overriding features have been identified that should prevent a transmission corridor in this area; however, First Nations communities in close proximity to the project would have interest in the options.

Moose River Basin Hydro Development

Project Description: The proposed project is a new 500 kV transmission line from the Moose River basin to the Sudbury or North Bay area. Approximately 1,000 MW of hydroelectric power potential has been identified in the Moose River Basin, with additional potential from development of the Albany River. To supply this power to load centres in southern Ontario, a new 500 kV transmission line would need to be constructed.

The total distance required for transmission from the Moose River Basin is 550 km. Two study areas have been identified due to the length of the proposed line. The north study area is from the Moose River Basin to Timmins and the south study area is from Timmins/Cochrane to Sudbury/North Bay.

Summary of Environmental and Socio-economic Analysis: Several northern communities are located within the northern study area (Moose River Basin to Timmins). Their economies are dependent on mining, forestry and natural resource development. The area is traversed by the Highway 11 corridor, oil and gas pipeline corridors, rail lines and several bulk electricity transmission corridors. There are three provincial parks, as well as several smaller settlement areas and First Nations communities in the study area. Small lakes, wetlands and rivers are located in the northern portion of this area.

The southern study area (Timmins/ Cochrane to Sudbury or North Bay) has similar ecosystem types as the northern study area and is characterized by natural resources-dependent economic activities. Several First Nations communities are in the study area. This area is identified as having a stronger tourism potential than the area farther north. There are several provincial parks, as well as several communities along the Highway 11 corridor. It has a few parcels of agriculturally active land, but most of the study area is characterized by remote Canadian Shield and boreal forest.

Wetlands, water bodies and rivers are interspersed throughout much of the study area along with abundant flora and fauna. Several sensitive features of the natural environment are associated with the southern portion of area, including: Lake Temagami Group of Parks, the Kenny Forest Provincial Nature Reserve, Sturgeon River Provincial Park and Wanapitei River and Lake.

Several potential transmission line corridors have been identified that follow existing right-of-ways. Corridor options from Moosonee to Highway 11 could utilize the existing 500 kV transmission line right-of-ways. Several other potential corridors are identified from Timmins to Sudbury and then south. A second potential corridor is located from the Cochrane area to North Bay and south. A third corridor could be located from Timmins to Sudbury to North Bay and then south. The main difference between the first and second corridors is the degree to which they interact with built up areas. The Timmins to Sudbury corridor interacts with fewer built up areas, but this corridor affects more wetlands and aquatic areas. The Cochrane to North Bay corridor traverses more built up areas, agricultural areas and forest resources. From Sudbury to North Bay, the potential effects of corridor include interactions with urban settlement areas associated with North Bay, effects on provincial parks along the Highway 17 corridor, and effects on First Nations interests and tourism recreation areas north of Lake Nipissing.

North-South Transmission Reinforcement

Project Description: The proposed project is a new 500 kV transmission line from the Sudbury or North Bay Area to the Greater Toronto Area (GTA). The need for this line is to integrate hydroelectric and wind power potential in the north. To supply this power to load centres in southern Ontario, a new 500 kV transmission line would need to be constructed.

Summary of Environmental and Socio-economic Analysis: The total distance required for the transmission line is approximately 340 km. Four separate study areas have been identified due to the length of this proposed line, including (1) Sudbury/North Bay to Barrie/Orillia, (2) Barrie/Orillia to the GTA western access, (3) Barrie/Orillia to GTA eastern access, and (4) Oshawa area to Parkway station. From Sudbury to North Bay, the potential effects of corridor options are discussed in as part of the analysis of the Moose River development.

The northernmost study area includes the Sudbury/North Bay area to Barrie/Orillia area. A corridor from Sudbury to Essa station could parallel the existing right-of-way. Another corridor could be located south from North Bay roughly paralleling Highway 11.

This study area lies to the west and outside the boundary of Algonquin Park. Most of the study area is characterized by the Canadian Shield. It includes the Parry Sound and Muskoka Districts and Simcoe County. South of Sudbury and North Bay the landscape is characterized by tourism and natural resource industries. Moving south, the study area traverses Muskoka District and is increasingly dominated by tourism and cottaging. The cottage areas are located near and around Parry Sound, and several large lake complexes including Lake Muskoka, Lake Rosseau and Lake Joseph. Cottaging and recreational activity also occurs from Honey Harbour north to the Wahta Mohawk First Nations Reserve. The southern part of the study area within Simcoe County is characterized by farming, recreational and sensitive ecological features north of Barrie.

Several First Nations communities are situated in this study area and will have a strong interest in the environmental assessment studies. For example, the Wahta First Nations Reserve (Wahta Mohawk Territory) characterizes the central portion of the study area to the south of Mactier. An existing 500 kV right-of-way traverses this area.

The study area is scattered with wetlands and significant water bodies. Numerous provincial Areas of Natural and Scientific Interest (ANSI) are prominent, as well as several ecological corridors and several provincial parks. For example the Oro Moraine may be affected. Specific routing studies undertaken as part of the Individual EA will need to account for these features.

The second and third study areas represent two corridor options from Barrie/Orillia to the GTA. This section of the transmission line is assessed as two study areas: a western access and an eastern access to the GTA.

The western GTA access uses the corridor from Essa station to Claireville station. The socio-economic and environmental features of the western access are discussed in the Barrie-South Transmission Reinforcement section, which addresses a potential transmission reinforcement from Barrie-South. It involves only one corridor option that avoids the physical constraints imposed by water bodies, but it does cross the Oak Ridges Moraine.

The third study area assumes a new corridor to the GTA, east of Lake Simcoe. The study area is bounded in the north by Orillia and in the south by Oshawa. The land uses in this area are predominantly farming, some forestry, cottages, recreational and tourism-related activities. The north-south route options are expected to be constrained by several large lakes on the east side of the study area and by urban settlement areas on the west side. Highway 12 and railway lines east of Lake Simcoe run generally north south through the study area. A number of settlement areas, First Nations lands, as well as Class 1 to 3 agricultural land are located in the central and southern portions of the area. Mixed deciduous and coniferous forests occur in the north part of this study area and woodlots occur in the south. Flora and fauna typical to southern Ontario characterize the area.

South of Beaverton station, a new transmission right-of-way would be required to the Oshawa area. A new Oshawa area transformer station would be required. This new corridor would generally follow Highway 12 and avoid socio-economic and environmental effects north of Toronto. This corridor also traverses a number of Class 1 to 3 agricultural lands. The corridor could avoid larger settlement areas, but to do so, it may interact with areas of aggregate resources. Wetlands and aquatic areas south of Beaverton and the Port Perry area would be traversed. Also, woodlots, forested areas and the Oak Ridges Moraine would be crossed. This corridor has the potential to affect First Nations communities, cottages and recreation resources.

The fourth study extends from the Oshawa area to the Parkway station. The corridor would feature an additional two circuit 500 kV transmission line within the existing Parkway Belt right-of-way. Parts of this transmission line are already approved. While such a transmission line may not create significant socio-economic effects along the existing right-of-way, urban development has occurred since the existing transmission lines were placed in service. Additional work will need to be completed to assess the extent of socio-economic effects. Settlement features within the 500 meter study area and abutting the right-of-way include golf courses, residential subdivisions, schools and institutional land uses.

The right-of-way crosses continuous parcels of Class 1 agricultural lands south of Highway 2, between Hampton and Brooklin and in northeast Ajax. Contiguous parcels of agricultural land and natural areas are also potentially affected in North Pickering. The environmental assessment study will need to determine whether and how the new transmission facilities interact with Seaton Lands that are scheduled for development. There are no major landforms, crown game preserves, non-governmental nature reserves, or national wildlife areas to consider; however, the current right-of-way crosses the Rouge Park.

Barrie-South Transmission Reinforcement

Project Description: A number of potential generation developments could result in the need for more electricity transmission capacity from Barrie to the GTA. The transmission capacity in this corridor is currently adequate but, over the course of the planning period, this is expected to change if significant renewable resources are developed in northern Ontario. The prospective reinforcement project involves a new 70 km 500 kV transmission line in the existing right-of-way from Essa station (west of Barrie) to Kleinburg station (near Kleinburg) to Claireville station (in Vaughan at Highways 427 and 7).

Three potential right-of-way alternatives are apparent for this project, including (1) within or on the east side of the existing right-of-way, (2) within or on the west side of the existing right-of-way, or (3) expanding the width of the existing right-of-way on either side. A new transmission line within the existing right-of-way would be expected to have fewer natural environmental impacts than expanding the width of the right-of-way to accommodate a new line.

Summary of Environmental and Socio-economic Analysis: The study area consists of the current 500 kV right-of-way from the Essa station to the Claireville station, and extends to 500 metres on either side of the right-of-way. Claireville station is north and outside of the Parkway Belt.

Environmental effects of a major transmission line project in the study area are generally predictable as these effects were initially identified when the existing 500 kV lines were constructed. Access roads for construction are already in place. The study area passes through portions of Simcoe County and York Region. Careful consideration would have to be given to avoid effects to the built up areas and residential subdivisions in the Woodbridge area of Vaughan.

The south end of the study area includes portions of three park and conservation areas, an industrial park, farms and rural residences. The middle portion of the study area is characterized by farm businesses and areas of Class 1 and 2 agricultural soils. The north end of the study area includes two small parcels of organic soils, but there are no prime agricultural lands. A number of linear corridors cross the study area, including an oil and gas pipeline and rail lines.

Most of the study area has limited areas of aquatic and terrestrial ecological significance. A wetland complex is located just outside the study area near the Essa station. An assessment of the effects of the project on these wetlands would be required. There are numerous warm streams in the study area, and seeps and coldwater streams are located on the north and south slopes of the Oak Ridges Moraine.

The right-of-way traverses 7 km of the Oak Ridges Moraine Conservation Plan area in King Township in York Region. This area would not have featured prominently in the environmental studies for the existing right-of-way, but interaction with the Oak Ridges Moraine is likely to have more prominence today. Other than this feature, there are no major land use features in the study area.

Parry Sound Wind Development

Project Description: There is the potential for 800 MW of wind north of Parry Sound in the Byng Inlet area. The project would include the construction of a new 230 kV transmission line between the existing two 500 kV transmission lines linking Hanmer station (north of Sudbury) and Essa station (west of Barrie), beginning at Parry Sound station. The line would extend the existing 230 kV line from Essa to Parry Sound an additional 100 km to the Byng Inlet area. From the existing 500 kV right-of-way, the new line would turn west to a point in the Byng Inlet area.

Summary of Environmental and Socio-economic Analysis: The study area is 500 meters either side of the existing 500 kV right-of-way. The existing right-of-way is located in remote areas of the Canadian Shield. It interacts with few settlement areas, although there are five First Nations within 15 kilometres of the right-of-way. Several rivers and the Magnetawan Provincial Park may be affected. As it is located within the existing right-of-way, environmental and socio-economic effects are known.

Bruce-GTA Transmission Reinforcement

Project Description: There is insufficient transmission capacity to move all the power from Bruce Power nuclear generating station through the existing transmission system to the GTA. The existing transmission system is only adequate for six of eight units at Bruce Power. The Bruce area also has potential for additional wind generation.

Two transmission corridors that could potentially accommodate a new 500 kV transmission line from Bruce to the GTA area have been examined. Each option follows existing right-of-ways and has potential socio-economic and environmental effects. Both options start at the Bruce nuclear plant, make a crossing of the Niagara Escarpment and end at the Claireville station (in Vaughan at Highways 427 and 7). One corridor is routed through Milton SS and the other is routed through Essa station (west of Barrie).

In more detail, the first corridor extends from Bruce Power following the existing 500 kV right-of-way to a point north of Orangeville station. From this point the corridor follows the existing 500 kV corridor to Milton SS. From Milton, the corridor follows the existing 500 kV right-of-way to the Claireville station.

The second corridor follows the existing 500 kV right-of-way to the point north of Orangeville, where it turns south and then follows the 230 kV right-of-way to the Orangeville station. From this point, the corridor follows the existing 230 kV right-of-way from Orangeville station to Essa station. The corridor then connects with the Claireville station following the existing 500 kV right-of-way.

Summary of Environmental and Socio-economic Analysis: The proposed Bruce to Milton transmission corridor avoids the Oak Ridges Moraine, and parallels existing 500 kV lines. The corridor follows existing right-of-ways, traverses Class 1 to 3 agricultural land and encroaches upon several lakes and conservation areas between Orangeville and Milton. This corridor crosses the Niagara Escarpment in the Milton Area and traverses areas of aggregate resources.

An environmental assessment of the Bruce to Milton right-of-way was completed in the 1970s, but environmental and socio-economic conditions may have changed since that time.

Corridor two, although following existing right-of-ways, also encroaches upon several lakes and conservation areas between Orangeville station and Essa station. It traverses prime agricultural land and areas characterized by quarrying activities. It avoids the Canadian Forces Base Borden, although it traverses a wetland south of the base.

Both route options interact with small rural settlement areas. More detailed route analysis by the project proponent would need to be conducted to determine the degree to which agricultural effects could be minimized and effects upon settlement areas could be avoided.

Bruce Peninsula Wind Development

Project Description: There is potential to develop 400 MW of wind generation on the Bruce Peninsula. The prospective transmission project to connect this wind is a new 230 kV transmission line from Owen Sound to the Tobermory Area. The southern terminus would be at or near Owen Sound, and the northern terminus would be south of Tobermory. The project is constrained south of Owen Sound by the existing transmission constraints that are discussed in the Bruce-GTA Transmission Reinforcement project.

Potential alternative corridors have been identified by Hardy Stevenson as part of the project-level assessment, but these corridors will need to be revisited during the environmental assessment process for the project.

From Tobermory south to Hepworth only one potential corridor is available, roughly following Highway 6. Three potential corridors have been identified from Hepworth to Owen Sound. Corridor one follows a rail right-of-way and Highway 6 from Hepworth to Highway 21, and continues to south of Owen Sound to the connection point at Owen Sound station. Corridor two proceeds from Hepworth roughly north of Highway 21 until just west of Owen Sound, then follows a route common with corridor one. Corridor three extends from Hepworth south along a rail right-of-way and intersects with the existing 230 kV line, then follows the existing 115 kV right-of-way to the Owen Sound station.

Summary of Environmental and Socio-economic Analysis: There currently are no high voltage transmission lines to the north of Owen Sound. The area is currently serviced by low voltage distribution lines. In the northern Bruce Peninsula, the new corridor will interact with several national parks, provincial parks and nature reserves. There are several areas of natural and scientific interest, and the area's economy is strongly dependent on tourism. Additional data collection and analysis will be required through the environmental assessment process.

The study area avoids most of the Niagara Escarpment area. The Bruce Peninsula is characterized by several important recreation resources including Bruce Peninsula National Park and the Cabot Head Provincial Nature Reserve. The project will be of interest to local communities and First Nations. Several First Nations communities and Bruce County municipalities exist in the study area. The City of Owen Sound is the only larger urban area, but other smaller urban areas include Lion's Head, Wiarton, Hepworth and Tobermory.

The local electricity distribution line, one pipeline and two active and two inactive rail lines transect the study area from Owen Sound to the central portion of the area at Lion’s Head. A 230 kV line is located in the southern part of the study area. Class 1 and 2 agricultural soils exist in contiguous and interrupted parcels throughout the area, but much of the central portion is unsuitable for agriculture.

Several natural features characterize the southern Bruce Peninsula, including Lion's Head Provincial Nature Reserve and Rankin Provincial Resource Management Area. A lake complex is located in the central portion of the study area, and numerous wetlands and watercourses are associated with the lake complex. There are wetland complexes over large parts of the area.

Darlington B Incorporation

Project Description: Several large generation and transmission projects in eastern Ontario are possible in the coming years, including a high-voltage interconnection with Quebec, renewable energy source development and potential expansion at Darlington nuclear generating station. Some development in eastern Ontario can be accommodated by the existing system, but if there is anything beyond a moderate amount of new supply or the Quebec interconnection, will require new transmission.

Approximately 20 km of an additional two-circuit, 500 kV transmission line is proposed for construction in an existing right-of-way from Bowmanville SS, adjacent to Darlington nuclear generating station, to a possible new Oshawa area transformer station. Parts of this transmission line have already been approved. The corridor west of the new Oshawa station is addressed in North-South Transmission Reinforcement.

Within the existing right-of-way, three options are identified. These options include a new 500 kV line: (1) between the existing tower lines, (2) north and east of the existing tower lines, or (3) south and west of the existing tower lines.

Summary of Environmental and Socio-economic Analysis: The study area boundaries include a 500 metre swath outside of either side of the existing transmission right-of-way. The right-of-way crosses some continuous parcels of Class 1 agricultural land south of Highway 2 and scattered parcels of Class 2 agricultural land. At this stage in the analysis, there do not appear to be any heritage features that cannot be avoided by the new line.

Subsequent environmental assessment studies will need to evaluate specific route alternatives in light of these interactions.

The area is generally composed of developed lands. There are no major landforms, crown game preserves, non-governmental nature reserves or national wildlife areas inside the study area. Some wetlands are located along the existing right-of-way.

In terms of natural features, all route alternatives appear equivalent, with no significant environmental features requiring mitigation.

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APPENDIX 6

Integration Discussion Paper No.7.


ONTARIO POWER AUTHORITY

November 15, 2006


Ontario's Integrated Power System Plan

Discussion Paper 7: Integrating the Elements — A Preliminary Plan

Ontario Power Authority™

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November 15, 2006

To Ontario's Electricity Consumers and Stakeholders:

I am pleased to deliver for your consideration "Discussion Paper #7: Integrating the Elements – A Preliminary Plan," the Ontario Power Authority's (OPA's) seventh of eight papers on the Integrated Power System Plan (IPSP).

Building on the OPA's "scope and overview" paper (#1) released in June, each paper in this series focuses on specific aspects of power system planning. Together, they provide our current assessment of the building blocks for the IPSP. The feedback they generate will provide important guidance for the development of the eventual regulatory filing. The table on the next page outlines the complete list of IPSP discussion papers.

The purpose of this "integration" paper is to elicit discussion on how the OPA's Preliminary Plan uses sustainability-based principles to integrate the elements developed in the other discussion papers – load forecast, conservation and demand management, supply resources and transmission. The OPA's objective is to ensure the highest success in meeting Ontario's need for a secure, sustainable and adequate supply of electricity that is acceptable to Ontarians over the long term.

For details on how to participate in the stakeholder event on November 22 to 24, 2006, and to provide input on the integration paper or other IPSP matters, please see the OPA's dedicated IPSP website (www.powerauthority.on.ca/IPSP/).

In the months ahead, I look forward to receiving your advice, thoughts and comments, and to sharing with you other planning documents as they are developed. In addition to the comprehensive report we are releasing today, the eighth and final discussion paper will be released later in November.

I strongly believe that developing a shared understanding of the planning challenges and the concrete steps needed to address them will focus the discussions, improve the dialogue and ultimately result in a better plan for the benefit of all Ontarians.

Yours sincerely,

Amir Shalaby
Vice-President, Power System Planning

OPA’s IPSP Discussion Papers

#	Discussion Paper Title	Release
1	Scope and Overview	June 29
2	Load Forecast	Sept. 07
3	Conservation and Demand Management	Sept. 22
4	Supply Resources	Nov. 9
5	Transmission	Nov. 13
6	Sustainability	Nov. 10
7	**Integration**	**Nov. 15**
8	Procurement	Nov. 24

NB: For details on stakeholder input and participation opportunities (and other IPSP matters), please see www.powerauthority.on.ca/IPSP/, the OPA’s dedicated IPSP web page.

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1. Summary and Introduction

This paper presents the Ontario Power Authority's (OPA) preliminary 20-year Integrated Power System Plan (IPSP), taking the province's electricity system through to the year 2027. It outlines the context and purposes of the plan, the process for evaluating it, the resulting Preliminary Plan and the next steps.

The Preliminary Plan outlined in this paper represents a significant new opportunity for Ontario: it is the first time that sustainability-based principles – feasibility, reliability, cost, flexibility, environmental performance and social acceptance – have been used to integrate the elements of the province's power system. The elements of the plan – load forecast, conservation, supply resources and transmission – are discussed in the preceding IPSP discussion papers. The concept of integration and its development and evaluation criteria are explained in this paper.

The Preliminary Plan is a work-in-progress. The OPA's objective in this paper is to increase stakeholder understanding about the many considerations involved in developing a plan. When approved, the IPSP will serve as both a focused implementation plan for the near term and a road map for the longer term.

Purposes of the Plan

The IPSP is unique because the industry structure in Ontario is a hybrid, unbundled sector and the OPA is not an asset-owning utility. Consequently, the purposes of the plan are as follows:

- increase public understanding of drivers, risks and opportunities
- provide a road map for decisions based on independent, expert analysis and assessments
- explain how CDM, generation and transmission will be integrated and implemented
- propose ways to manage uncertainties in the short and long runs
- suggest initiatives for electricity sector evolution in the medium term
- describe the results of alternative expansion paths on costs and the environment
- present the rationale for projects that the OPA finds to be in the public interest
- identify infrastructure needs and secure regulatory approvals for timely implementation.

The plan is a mechanism by which key electricity system, sustainability and government policy requirements are met. With the input from the stakeholder consultation in hand, the OPA will refine the Preliminary Plan over the coming weeks and months into a recommended plan that the OPA will file with the Ontario Energy Board (OEB) in the spring of 2007.

Near-Term Actions, Long-Term Options

By developing the IPSP, numerous decisions will be framed for the timing, location, size and type of resources to deploy in order to achieve Ontario's policy objectives. The plan provides the basis for decisions in the short term, for developing options in the medium term and for exploring opportunities in the long term.

Ontario will be a very different place 20 years from now, one where its electricity generators, transmitters and consumers will have undergone a remarkable change in the way they produce, deliver and use electricity. The transformation is being driven by sustainability considerations, government policy, technological change, consumer choices and opportunities in the marketplace. The IPSP will help guide Ontario to a future where:

- total electricity consumption increases, but consumption per person, per dollar of economic output and per household all decline, reflecting increased energy efficiency
- generation resources change sharply – coal is phased out, new natural gas and renewable energy play an increasing role and nuclear baseload capacity is restored to its historic level
- generation emissions decline precipitously or are eliminated
- several major transmission corridors are reinforced or developed to support new resource developments and to supply power to growing areas
- risks are allocated efficiently between the private and public sectors to provide the services and infrastructure required.

As with the *Supply Mix Advice Report*, the OPA has endeavoured to assess the impacts of the Preliminary Plan on aggregate indicators. While these are rough metrics, they tell a similar and significant story on an expected transformation in electricity use.

Preliminary Plan – An Illustration

The Preliminary Plan contains a great deal of information. While there are no hard dividing lines, there are three recognizable time periods within it. These are evident in the three discrete segments illustrated in Figure 1.1. Highlighting the different challenges, risks and decisions that characterize each one is helpful to understanding the plan.

There is, however, one overriding theme with respect to the successful implementation of the Preliminary Plan across the three periods. For the plan to be feasible, not only are many actions required now to support the immediate and near-term needs, but also many actions are required now to develop options for the medium term and explore opportunities for the longer term. All of these actions need to be supported on an ongoing basis. The three time periods are as follows:

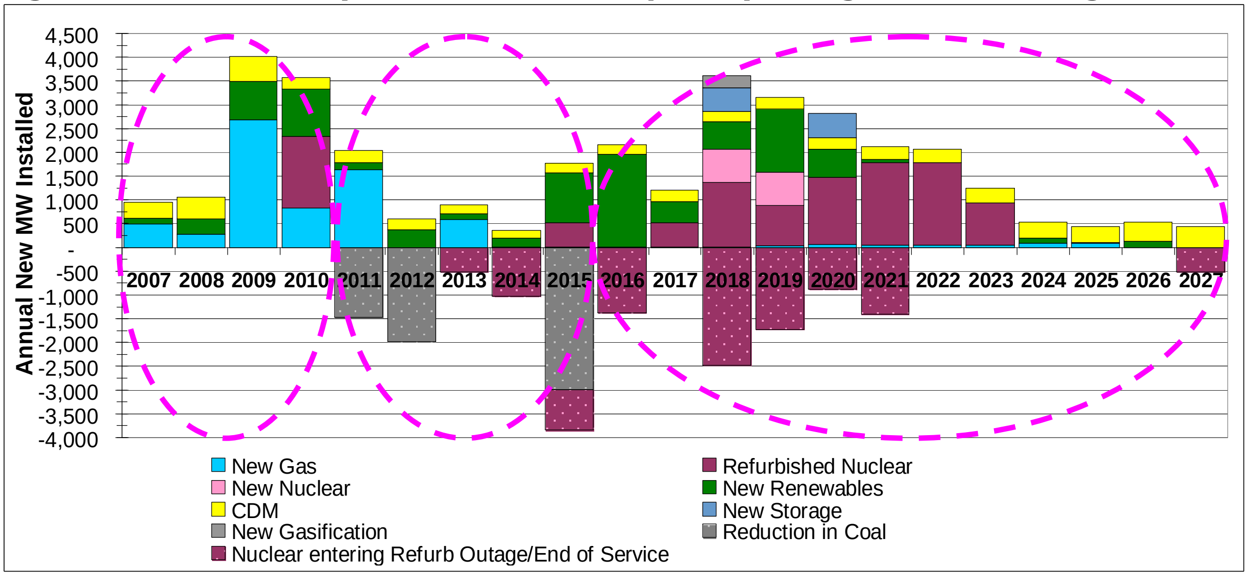
Near Term: The plan develops the basis for implementing the choices that have already been made and the projects that will begin within the next four years. In this timeframe, the basic elements of the plan are well defined, including for CDM, where implementation of the plan has begun to meet the requirements of several ministerial directives.

Medium Term: The plan develops options that are likely to be needed in the next period, i.e., five to nine years from now. Taking actions now to develop these options will result in a portfolio from which Ontario can make appropriate choices in the medium term. In the case of CDM, the learning and successes from the evaluation, measurement and verification (EM&V) process serve as a platform to build on. Developing options requires investing in studies, approvals and pre-engineering, and acquiring land and equipment to enable options to proceed on shorter lead-times.

Long Term: The plan assesses "big-picture" risks and opportunities and identifies and scopes a set of broad options. It also identifies ways to make decisions now that will prove robust in the face of various future possibilities.

The key building blocks of the Preliminary Plan are detailed in Figures 1.1, 1.2 and 1.3.

Figure 1.1 – Preliminary Plan – Resource Capability Changes over Planning Horizon



Source: OPA

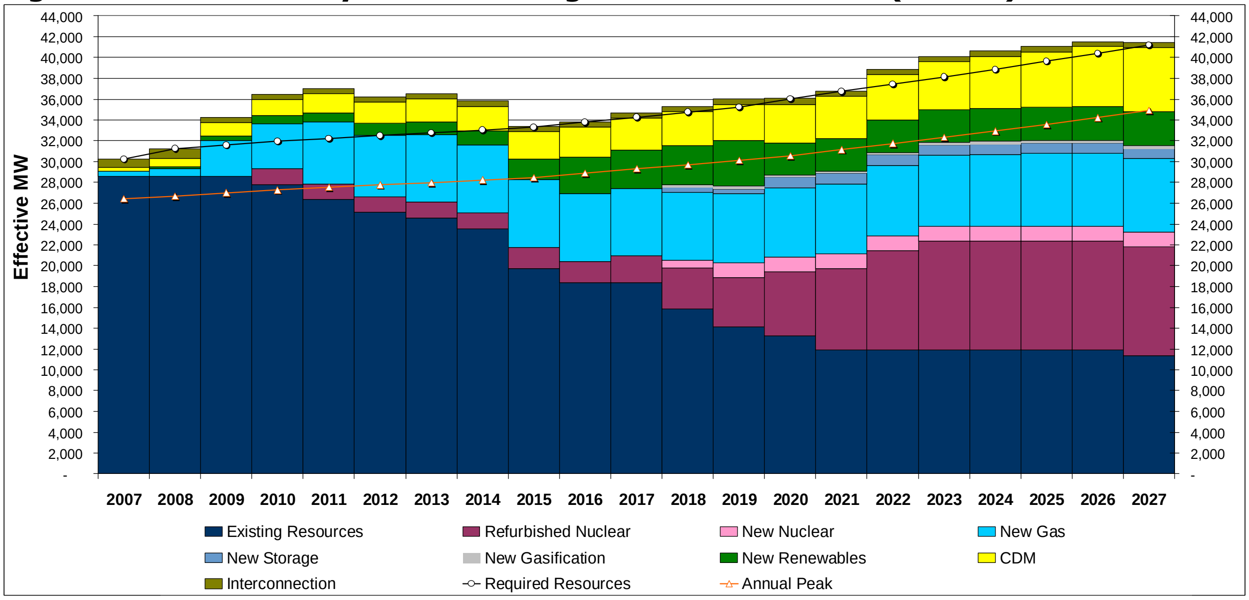
Figure 1.1 provides a comprehensive picture of the Preliminary Plan. It shows the different resources that are being added or taken out of service during each year and the circles show what we describe are the near-term, medium-term and long-term stages.

The near-term stage shows the resources that have already been committed. The near and medium term together illustrate that approximately 15,000 MW of new and refurbished supply and conservation resources are planned for in-service dates between 2007 and 2015. In the long-term stage, another 15,000 MW of resources are placed in service between 2016 and 2027. Coal retirements and nuclear resources entering outage for refurbishment or end-of-service approach 17,000 MW over the 20-year period.

The results in Figure 1.2 are similar to Figure 1.1 but are shown to focus on the contribution of resources to meeting reliability. There is a reasonable degree of certainty about how the demand-supply gap will be filled in the period up to 2015. Beyond 2015, however, there is a wider range of possibilities.

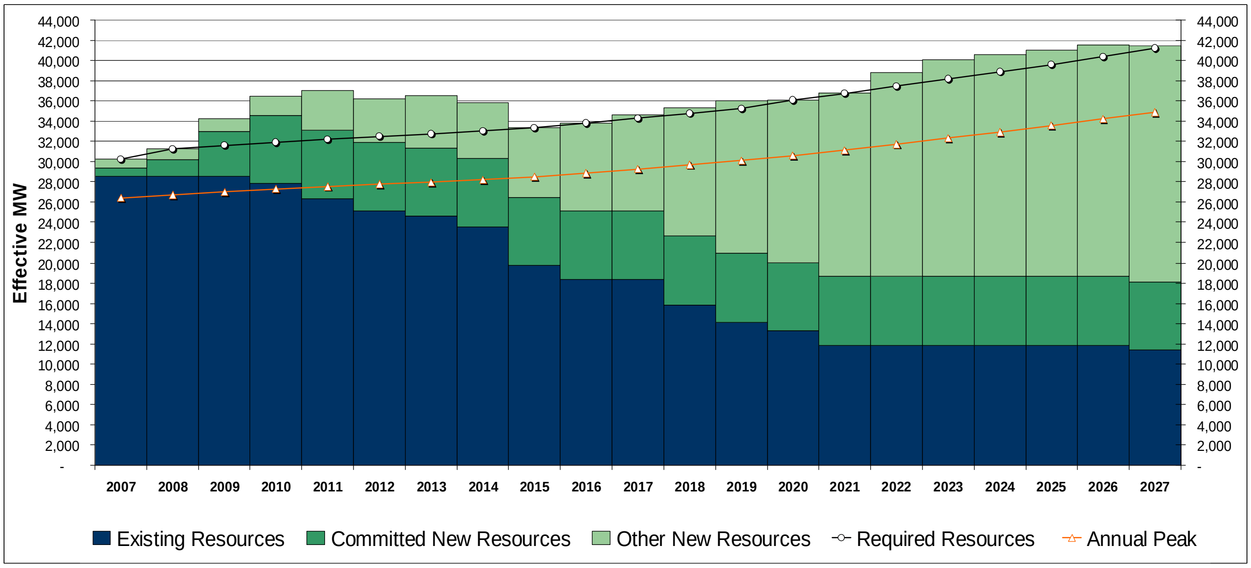
The period to the end of 2014-2015 sees a dramatic transformation. It involves the replacement of Ontario's coal-fired fleet, a doubling in the amount of installed natural gas-fired generation and an increase in overall nuclear capacity as the Bruce A units are restarted. During the same period, the Preliminary Plan includes steady increases in the amount of CDM and renewable resources. Risk around the implementation and performance of new resources is managed by the timing of coal replacement and by imports.

Figure 1.2 – Preliminary Plan – Existing and New Resources (Details)



Source: OPA

Figure 1.3 – Preliminary Plan – Existing, Committed and New Resources



Source: OPA

Between approximately 2015-2016 and 2022-2023, the Preliminary Plan enters another period of transition, as nuclear units are refurbished and retired, CDM plays an increasing role in the supply mix and the amount of installed renewable resources nearly doubles from the current level.

In the latter part of the third period, from 2023 onwards, the plan is subject to a variety of major uncertainties, including around the load forecast, success in capturing resource potential and technological innovation.

A summary of energy production for the years 2010, 2015, 2020 and 2025 is given in Table 1.1, which reflects both energy imports and exports with neighbouring jurisdictions by aggregate resource type.

Table 1.1 – Preliminary Plan – Energy Production (TWh)

	2010	2015	2020	2025
CDM	6	9	13	19
Renewable Resources	42	49	60	60
Nuclear	91	88	79	103
Natural Gas and Oil	21	30	30	27
Storage & Gasification	0	0	3	3
Coal	15	0	0	0
Total	175	176	185	212
Imports	4	5	7	4
Exports	18	14	11	18
Net Exports	14	9	4	14
Ontario Demand	161	168	180	196

Source: OPA. A terawatt hour (TWh) is a trillion kilowatt hours.

Table 1.1 shows that total energy production increases by about 37 terawatt hours (TWh) between 2010 and 2025, representing an increase of almost 21 percent. Over the course of the Preliminary Plan, nuclear production increases by 12.3 TWh, or by about 14 percent relative to 2010 levels; renewable energy production during the same period increases by 18 TWh, or by 42 percent; gas/oil production increases by 30 percent; and energy conserved increases by 195 percent.

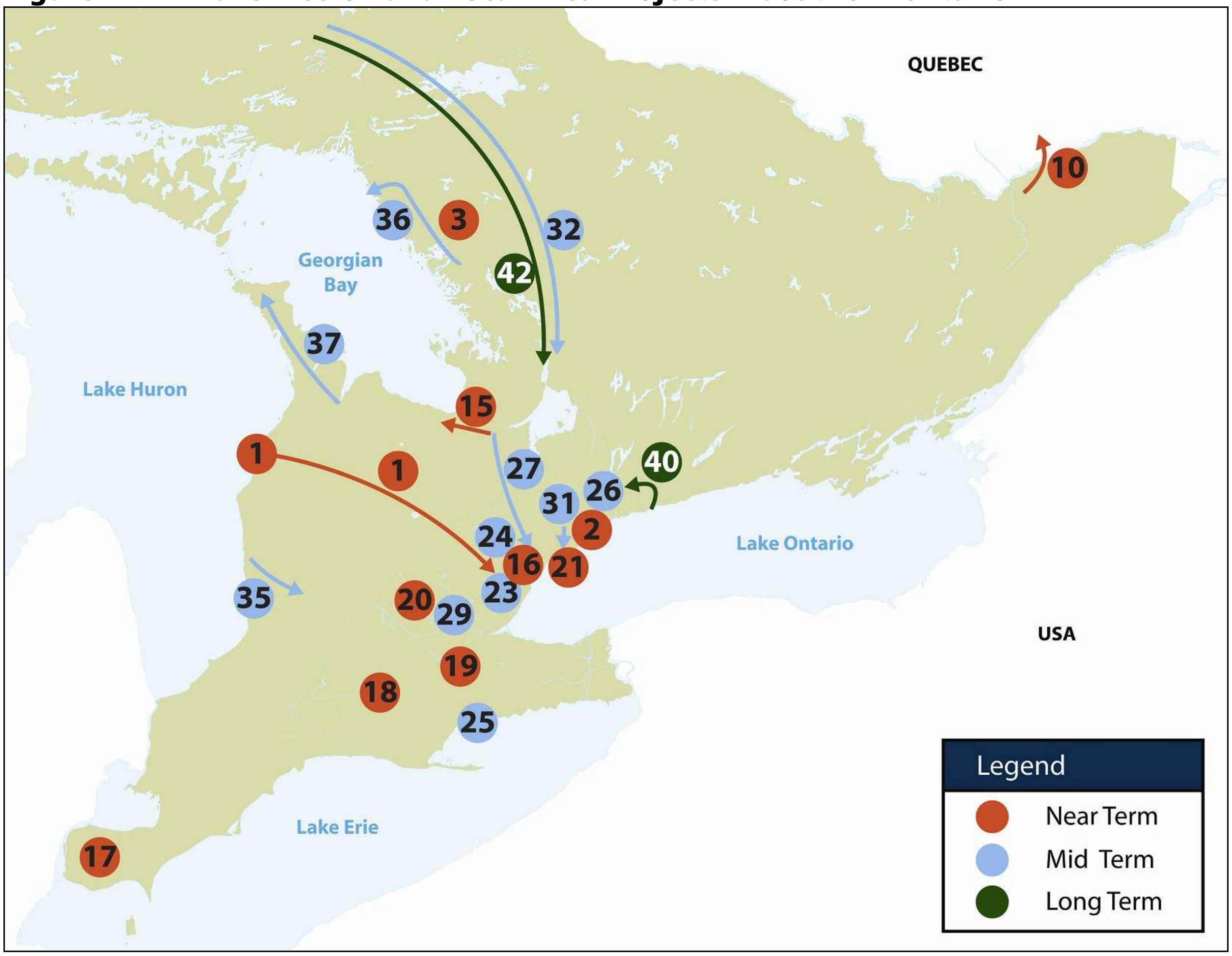
As part of total energy production, the data supporting Table 1.1 indicate that, while natural gas-fired production increases from 10 percent in 2010 to 17 percent in 2015 and 2020, it actually is reduced to 13 percent by 2025; renewable resources increase from 24 percent to 28 percent; nuclear production remains relatively constant; energy conserved represents nine percent of total energy by 2025; and coal is not part of the energy production by 2015.

Preliminary Plan – An Overview

The IPSP is a roadmap. The route for the first few years is largely set. The route over the subsequent few years permits some variations, while the route over the longer horizon is only directional and can be changed in response to events as they unfold. The plan offers guidance for the entire planning period, providing an appropriate level of detail and specifics while recognizing that there will be many changes and, therefore, maintaining flexibility is important.

Figure 1.4 and Figure 1.5 illustrate the preliminary locations of proposed supply resources and transmission lines. The projects enumerated on the map are described in more detail in section 4 and in summary below.

Figure 1.4 – Transmission and Local Area Projects – Southern Ontario



Source: OPA

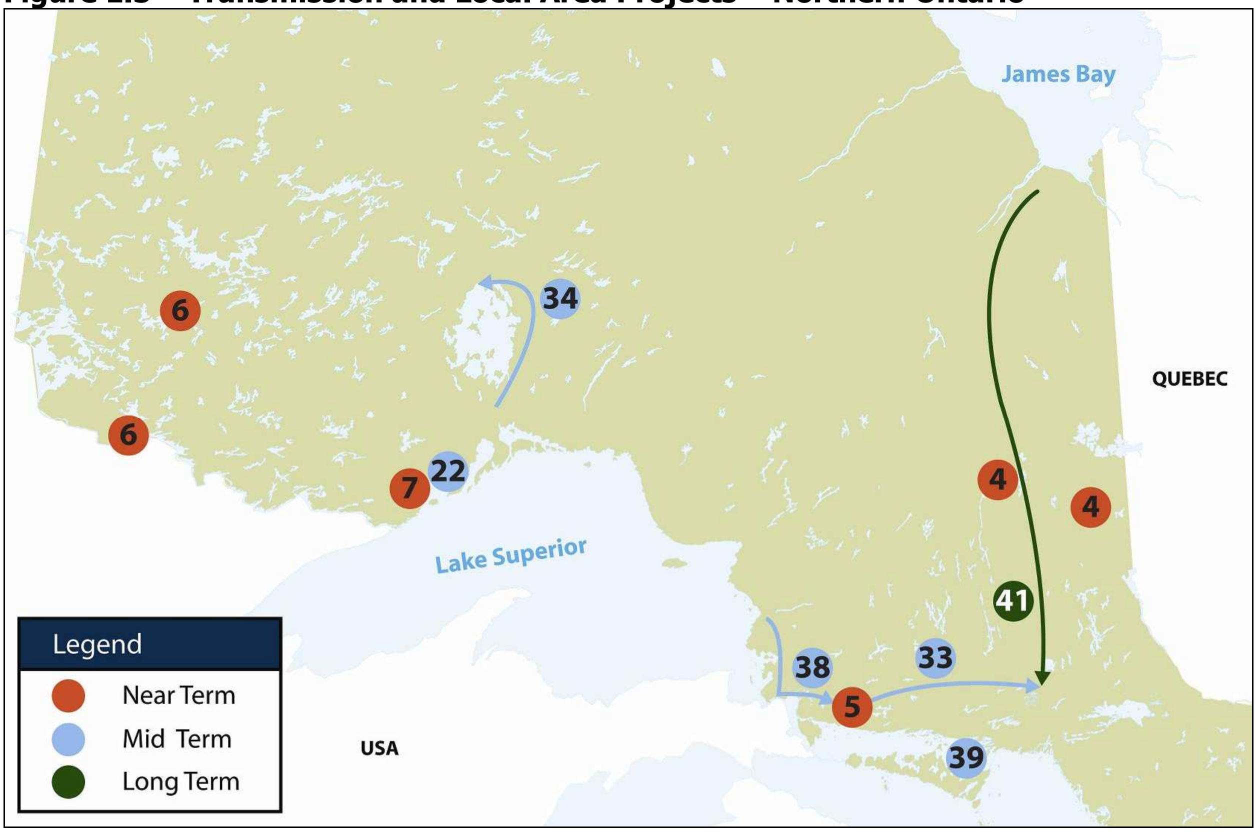
A Focused Near Term – 2007-2010

Over the near-term period, Ontario's supply situation will improve but there are many uncertainties. Output from coal-fired generation is likely to be needed throughout the period. Imports may also be needed on peak demand days. The challenge in the 2007-2010 timeframe is to deliver the following:

- additional CDM programs to achieve energy savings and demand reductions in the priority areas identified in the discussion paper on CDM (#3)
- hydroelectric resource development around the province

- transmission investments to ensure deliverability of the output from Bruce Power's refurbished units and potential wind resources in the area
- increased interconnection capability with Quebec
- significant additional procurement of combined heat and power (CHP) resources
- coal phase-out plan to be implemented
- a number of urgently needed natural gas generators, including those in northern York Region and around Kitchener
- transmission reinforcements in the GTA, southern Georgian Bay, Windsor, Brant, the Kitchener area and Woodstock
- develop a comprehensive framework for evaluation of CDM.

Figure 1.5 – Transmission and Local Area Projects – Northern Ontario



Source: OPA

In addition, decisions are needed in the near term to enable the resources that will be required in the medium term. In particular, the refurbishment of Pickering B should be explored further and decisions on this resource made before 2010. Firm decisions need to be made within the next few years regarding potential purchases from other provinces under long-term contractual arrangements.

Medium Term: Develop Options – 2011-2015

In the medium term, the supply situation will continue to improve. The extent of improvement will largely depend on the degree of success in securing CDM and renewable resources and building transmission (from Bruce in particular). While supply will improve, the sharp transformation of the resource mix will introduce new patterns of electricity flow and new operational risks.

There are two main challenges for this medium-term period – incorporating the next tranche of renewable resources and either proceeding with the Pickering B refurbishment or pursuing alternatives to it. Decisions on additional nuclear refurbishments and their coordination will need to be made in the early part of this time period.

In the 2011-2015 timeframe, there may be some opportunities to modify current choices in the next IPSP, depending on the actual performance over the next few years in securing CDM and integrating committed renewable resources. For example, good progress on implementing both CDM and renewable energy will accelerate the phase-out of coal and might reduce the urgency of securing other new supply resources.

With this context, the integration analysis completed to date suggests that generation and transmission proponents should help develop the following options for the 2011-2015 period:

- refurbishment assessments for Bruce B and Darlington and coordination of outages
- north-south transmission reinforcement
- Toronto third supply
- Sudbury west transmission reinforcement
- Lake Superior east wind development
- Parry Sound wind development
- Barrie-south transmission reinforcement
- Little Jackfish and East Nipigon wind development.

Other opportunities include the potential to secure renewable energy from neighbouring provinces and the potential to rely on more market-based mechanisms for procuring new CDM and generation. Decisions for the long term must be made in this period, primarily those concerning Bruce B and Darlington refurbishment.

The uncertainties in this time period could be partially mitigated by increasing imports on a short-term basis, assuming power is available on reasonable terms to meet Ontario's requirements. New natural gas-fired generation can also provide insurance, but it would not be prudent, or consistent with the “smart-gas” strategy, to initiate a significant round of new gas investments now just to cover the uncertainties in this period.

Coal-fired generation potentially can be replaced by 2011-2012. Reliability considerations suggest, however, retaining the option of maintaining about 3,000 megawatts (MW) of coal capacity until 2014 as insurance against possible delays in acquiring other resources. Plans to reduce the environmental impacts of coal-fired generation that remains in service are currently being developed.

Section 4 of the paper provides further details on these suggested near-term actions and additions, as well as a number of smaller initiatives.

Longer Term: Opportunities to Explore – 2016-2027

Key resource developments in this period include the refurbishment or retirement and replacement of existing nuclear units, along with potential development of greenfield hydroelectric sites in northern Ontario.

Beyond 2016, there is a wider choice of resources. Given that there could be significant changes in demand, technology and other factors relative to what we currently expect, it is desirable to develop a portfolio of supply possibilities from which to choose. In effect, this means developing to various degrees more than the expected requirements. For the purposes of the Preliminary Plan, resource requirement in the long term should, therefore, be viewed as one of many possibilities in a range, not as an inflexible plan.

The Preliminary Plan includes certain resources that are seen as having potential within the period 2016-2027. These resources will need to be examined continuously as subsequent IPSPs are developed. For example, the plan foresees hydroelectric development opportunities in the Moose River Basin beyond 2020, and this would require new transmission.

In terms of possibilities, the 2016-2027 timeframe clearly will be affected by events that happen or begin to happen in the near and medium term. The following scenarios and their impact on the last 10 years of the plan will be considered as the plan evolves:

- a decision not to refurbish Pickering B
- a delay in the development of new nuclear capacity, with energy output unavailable to 2020 (versus 2018)
- a decision not to proceed with development of the Moose River Basin
- greater success in capturing the CDM resource
- success in negotiating a significant firm import from outside the province.

The plan should have sufficient flexibility to respond to or take advantage of these scenarios and still meet overarching objectives. The picture in the long term is less definitive than the near- and medium-term parts of the plan. It will continue to sharpen as time passes and more information becomes evident.

Plan Results and Implementation

The results of the plan present a startling picture of the transformation that will occur based on the projections of the Preliminary Plan.

The plan will be implemented through decisions by various parties. In the near term, the OPA will be responsible for acquiring many of the new resources through CDM and generation procurements. These activities will require partnerships and close coordination with project developers and product and service providers. In the long term, the OPA is expected to have a smaller and less direct role in plan implementation.

Implementation

Many aspects of the Preliminary Plan can be readily implemented within the existing policy framework, but other aspects will require further policy development. More work on the nature of the contractual and commercial arrangements for new supply will be necessary, particularly on nuclear projection, and on the long-term evolution of the sector as a whole.

Cost

The Preliminary Plan provides an initial projection of costs. New investments in transmission are needed beyond those already underway and the energy from most of the new generation resources is more costly than the energy from an average generator today. Ontario is also making important investments in its electricity infrastructure to rectify past under-investment and to meet future needs.

Based on initial estimates and reasonable ranges of projected costs, the cost of energy will increase by up to 15 percent by 2025 in real terms. While per kilowatt hour costs will rise, Ontario electricity customers who take advantage of conservation opportunities will experience a decrease in their bills. A household that takes advantage of conservation can see bills going down by as much as 12 percent by 2025.

Efficiency

The conservation initiatives will have an important effect on electricity consumption, as illustrated in Table 1.2. In particular, efficiency measures targeted by CDM programs are anticipated to reduce electricity consumption per person, per household and per dollar of economic output. This is significant given that Ontario's population and economy are expected to expand throughout the planning horizon.

Table 1.2 – Preliminary Plan – Aggregate Efficiency Indicators

	Electricity Consumption Per Person (kWh)	Electricity Consumption Per Household (kWh)	Electricity Consumption Per Dollar of Economic Output (kWh/$ of real GPP)
2005	11,608	9,145	0.32
2025	11,080	7,724	0.22
Decrease	528	1,421	0.10
% Decrease	4.5%	15.5%	31.25%

Source: OPA

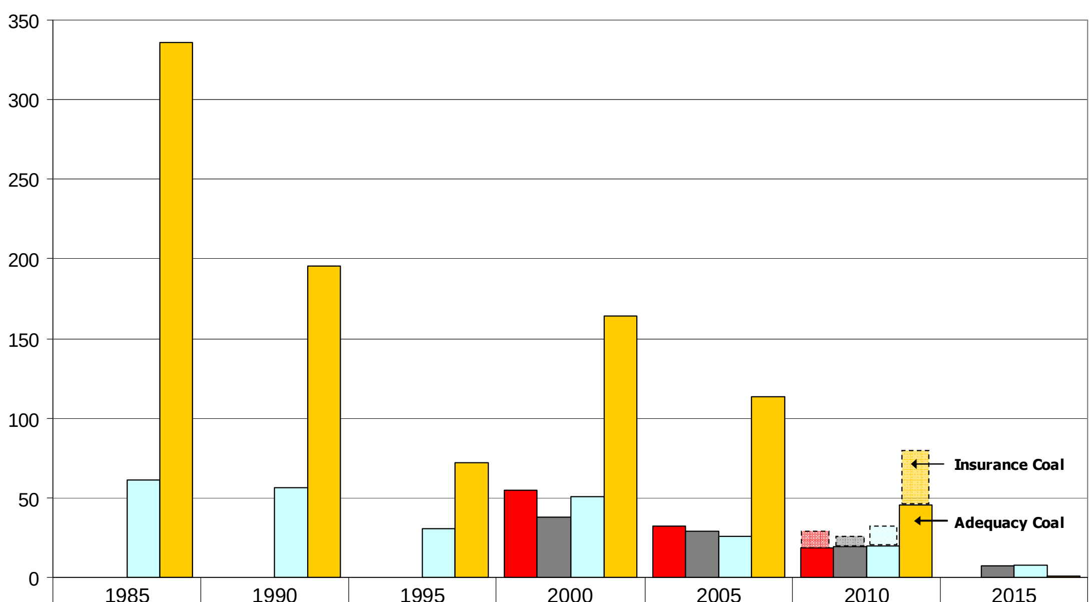
Generation

The Preliminary Plan seeks to build generation capacity in several areas. An aggressive target of 15,700 MW of capacity from renewable sources is planned. In terms of conventional sources, nuclear power will be employed to meet baseload demand requirements and will be maintained at the current rate. Although nuclear waste will continue to be generated at the current rate, funds are being set aside and technological capacity is being developed to manage waste effectively in the future. A "smart gas" strategy will be used for high value applications and to alleviate transmission bottlenecks, which will mitigate adverse effects associated with fuel price volatility and greenhouse gas (GHG) emissions.

Air Emissions

With respect to air emissions, the Preliminary Plan represents improvements in contaminant air emissions compared to the 2005 levels, and even more so compared to levels since 1985. Figure 1.6 shows past and expected results to 2025. The replacement of coal-fired generating units will contribute to a significant reduction of sulphur dioxide (SO_2), nitrogen oxide (NO_x), carbon dioxide (CO_2) and mercury (Hg) emissions. Notably, the difference between the use of coal for adequacy and what might be required for insurance for reliability purposes affects the representation of 2010 in Figure 1.6.

Figure 1.6 – Contaminant Air Emissions



	1985	1990	1995	2000	2005	2010	2015
Total Hg (kg/10)				55	32	**18 / 36**	0
Total CO2 (Tg)				38	29	**19 / 28**	7
Total NOx (Gg)	62	56	31	51	26	**20 / 39**	8
Total SO2 (Gg)	336	195	72	164	114	**46 / 96**	1

Notes: 1. NO_2 makes up a portion of NO_x (oxides of nitrogen). Nitric oxide (NO) is also emitted from coal-fired power plants.
Source: OPA

Over the past few decades, SO_2 emissions have declined significantly due in large part to government policy and the SO_2 emissions trading system that has been implemented. These emissions are projected to continue to decline dramatically over the planning horizon. This is important because SO_2 emissions contribute to acid rain. From 2010 to 2025, SO_2 emissions are expected to decrease by approximately 95 percent from electricity generation.

NOx is forecast to resume the downward trajectory initiated in the late 1980s that was interrupted around the turn of the century. The reduction in NOx, can have a favourable effect on human health. From 2010 to 2025, NOx emissions are forecast to decrease by approximately 58 percent from generating activities.

Data on Hg and CO_2 emissions are available from the year 2000. The phase-out of coal-fired generating units will reduce emissions of mercury to negligible levels by 2015. Mercury emissions are known to accumulate in the food chain and are linked to neurological damages in humans. From 2010 to 2025, mercury emissions are eliminated.

Emissions of CO_2 are also expected to decline significantly. GHGs have been linked to potential climate-change effects. From 2010 to 2025, CO_2 emissions from electricity generation are expected to decrease by approximately 61 percent.

Transmission

The transmission system will need to be enhanced to enable the capacity expansion projects identified in the Preliminary Plan. New transmission is required to facilitate increased generation from renewable sources, such as wind, hydroelectric and biomass. Land use impacts associated with transmission lines will be mitigated to the greatest extent possible, but without increased land use, the full benefits associated with renewable generation sources cannot be realized. Building new transmission also reduces congestion and increases system efficiency and reliability. Upgrades to the transmission system are required because of previous under-investment.

Developing the Plan – From Principles to Criteria to the Plan

Integrated resource planning is the process of combining the elements of a system to form a whole. Integration will typically involve iterations in making choices between elements, or modifying elements, to achieve the objectives of the whole.[1]

In the present context of developing a preliminary IPSP, our approach to integration is to be guided by criteria that reflect sustainability principles.

Evaluation Criteria for Long-term Electricity Planning

The integration of plan elements requires a practical set of development and evaluation criteria. The context-specific criteria encompassing sustainability principles derived in the sustainability paper (#6) are applied to guide IPSP decision-making processes. Table 1.3 summarizes the six criteria from the sustainability discussion paper and the role they play in integration.

The criteria are sufficiently robust to be applied to developing the IPSP and also to evaluating the Preliminary Plan. For example, with respect to environmental performance, the plan is developed with the intent of reducing GHG emissions, which is evident in the replacement of

[1] Integration may also be directed to achieving synergies. An example would be locating new wind resources to take advantage of new transmission capacity necessary to incorporate new hydroelectric resources. This would result in enhanced cost and environmental benefits.

coal-fired generation and in the "smart gas" strategy. The criterion is also sufficiently versatile to be used to evaluate the plan in terms of measuring GHG gas emissions using quantitative indicators.

In applying the criteria to establish a Preliminary Plan, resources are incorporated because they satisfy all criteria simultaneously throughout the planning horizon to the greatest possible extent. Due to the nature of integrated system planning, however, there are instances where trade-offs among the criteria are unavoidable. It is important to develop clear and consistent method for addressing trade-offs that can facilitate the greatest net benefits.

Table 1.3 – Context-Specific Development and Evaluation Criteria

Criteria	Description
Feasibility	Comprising technical feasibility, commercial availability, technological maturity, sufficient infrastructure and lead time and compliance with regulations, all of which must be present if resources are to be incorporated in the IPSP
Reliability	Resource adequacy and system security, which make up the components of this criterion, are necessary to maintain system reliability at all times throughout the planning horizon
Cost	Encompasses cost of options on the planning horizon, the value of conservation, cost of services to consumers and impact on customers' bills
Flexibility	Includes the flexibility of options in the future and the robustness of the plan to be sufficiently adaptable to a range of future scenarios
Environmental Performance	Includes the amounts of greenhouse gas (GHG) emissions, conventional contaminant air emissions, radioactivity, water use and wastes generated
Social Acceptance	Includes the matters that have significant socio-economic implications, meeting government policy and addressing stakeholder expectations

Source: OPA, Sustainability Discussion Paper (#6)

Feasibility and reliability are invariable in their application – all resources included in the plan must be feasible at the period of introduction in the plan and must not jeopardize reliability. The remaining four criteria are applied on a context-specific basis, depending on the circumstances of each particular decision. This will be contingent on the particular component of the plan being evaluated, how it may be interrelated with other parts of the plan and its implications for satisfying the development criteria.

Despite the context-specific nature of the evaluation of trade-offs, a set of general trade-off criteria is able to guide decision-making when trade-offs are encountered. These criteria are presented in the sustainability discussion paper (#6).

Building Blocks for the Plan

There are a number of "screens" that are used throughout IPSP discussion papers #1 through #6 that are the building blocks for the development of the integrated plan. Integration is about choosing which blocks are needed, and by when, to build the best possible system, given all objectives and constraints.

With integration the subject of this discussion paper, the building blocks of the plan, in chronological order, are the:

- sustainability framework and planning criteria (paper #6)
- reliability standards (North American Electric Reliability Council (NERC), Northeast Power Coordinating Council (NPCC), and Independent Electricity System Operator (IESO).
- stock of existing generation and transmission assets
- policy framework, as detailed in legislation, regulations and ministerial directives (paper #1)
- electricity demand forecast (paper #2) and required capacity as determined by projecting demand and incorporating a reserve margin of about 17 to 18 percent
- current conservation program initiatives and generation and transmission projects (papers #3, #4 and #5)
- resource options and their feasibility, as detailed in the discussion papers on CDM (#3), supply resources (#4), and transmission (#5)
- regulatory evaluation and approval criteria for the plan and certain individual projects included in the plan (OEB, forthcoming)

With these building blocks outlined, the process of integrating the plan elements begins.

Integrating the Plan Elements

Integration is typically not performed in a single step but rather requires iteration. In the present case, this occurs when an initial plan that meets basic system needs of feasibility and reliability is assessed for its performance to meet cost, flexibility, environmental performance and societal acceptance objectives. Based on such assessment, a second iteration is performed, leading to a refined plan. Further iterations are performed as appropriate.

Integrating the elements for the IPSP has been focused by the ministerial directive outlining the objectives for CDM resources, renewable supply, nuclear generation, use of gas, replacement of coal and strengthening of transmission. [2]

With this focus set, the major plan elements that must be integrated are CDM, existing and new generation resources – deciding on the nature, size, and location of the resources to be included in the plan, and the timing of their introduction – and transmission facilities associated with new generation resources. The resources to meet the requirements and criteria are considered in the following order:

- existing resources (excluding coal) and committed resources are considered first
- CDM resources are considered second
- potential renewable resources are considered third
- conventional resources are considered fourth
- other resources are considered, as required, to complete the picture, including short-term imports and the use of coal-fired generation in the near and medium term

[2] See Appendix A.

- transmission resources are then considered as the means for connecting the above resources and serving local area needs.

Incorporating Views, Requesting Stakeholders' Comments

Stakeholder engagement is a valuable and integral component of the process to develop the IPSP. Stakeholders have participated in and made valuable contributions to this process since the OPA began to develop the supply mix advice in 2005. As in our other stakeholder engagements, we will prepare a note on "What We've Heard" from stakeholders and an outline of how the OPA will respond to those stakeholder comments.

This paper is intended to elicit discussion on how sustainability considerations should guide the integration of the load forecast, conservation and demand management, supply resources, and transmission facilities identified in previous discussion papers into a single plan. We invite stakeholders to provide their input, in this case on the OPA's focus on integrating the elements of the plan.

In addition to the questions raised in this paper, the OPA is seeking comments from stakeholders and interested parties on the assumptions and methodologies used in developing the Preliminary Plan and on the findings to date.

Comments must be submitted to the OPA through one of the two following channels:

- Electronic submissions can be made through the on-line form at the following website link, which includes instructions for sending submissions as attachments: http://www.powerauthority.on.ca/ipsp/Page.asp?PageID=751&SiteNodeID=231&BL_ExpandID=155\
- Submissions by regular mail or courier can be sent to: IPSP Submissions, Ontario Power Authority, 120 Adelaide Street West, Suite 1600, Toronto, ON M5H 1T1

Given the volume of correspondence, submissions sent to specific individuals at the OPA cannot be assured of review and consideration.

2. Developing the Preliminary Plan

This section describes the sequencing of the development of the Preliminary Plan.[3] It utilizes the sustainability criteria and the previous discussion papers, as follows:

Step One: The total capacity requirement over the period is established, considering in particular the required reserve margin that must be added to the load forecast presented in paper #2. This is consistent with reliability, flexibility and societal acceptance.

Step Two: This capacity requirement is compared first with existing resources, as described in the supply resources paper (#4). Coal-fired resources are not included in this picture – coal-fired resources are presented once other supply and demand resources are determined, within the overall objective of replacing coal-fired resources as soon as practical. Using existing resources is cost-effective and feasible. Using coal last is consistent with societal acceptance and desired environmental performance.

Step Three: The resource picture continues to build up, with the additional contribution of committed resources, again, as described in paper #4. It is cost-effective to follow through with commitments, and it provides for a feasible way to meet reliability requirements.

Step Four: The contribution of new conservation resources in filling the resource gap between required and existing resources is given priority and included in the plan. The achievable capacity of the conservation resource was estimated in the CDM paper (#3). Using CDM resources is consistent with many aspects of the evaluation criteria.

Step Five: The contribution of new renewable resources (hydroelectric, wind power and bioenergy) in further filling the resource gap is developed. Consideration is given to the earliest available dates, unit energy costs, and environmental performance and social acceptance. Again, reference is made to paper #4.

Step Six: Conventional supply resources are then considered, including nuclear refurbishment and new nuclear capacity and peaking resources, and their contribution to meeting the resource gap, reflecting conclusions given in the supply resources discussion paper. Purchases from other provinces or the U.S. are considered as well.

Step Seven: At this point, all resource types except coal-fired generation have been incorporated. The coal replacement plan options are now considered, including the ability to meet the requirement for additional resources and to manage risks through to 2014. This completes the resource profile in relation to requirements. This is consistent with reliability and societal acceptance.

[3] The methodologies used in developing the plan are described in Appendix B. This section describes the quantitative integration of the resources that were analyzed in papers #3 to #5. Each of these papers fully reflects environmental and sustainability considerations. The environmental/sustainability considerations reflected in paper #7 are therefore additional to those reflected in the previous papers.

Step Eight: Transmission integration considerations are presented, building on conclusions given in the transmission discussion paper (#5) and informed by the other papers.[4] The discussion addresses options for expanding the transmission system to integrate different levels and locations of new renewable resources. This discussion concludes with a description of the transmission enhancements needed for the Preliminary Plan.

2.1 Step One: Required Capacity

Determination of Required Planning Reserve

The starting point is the load forecast described in the load forecast paper (#2). We initially assumed a required planning reserve of 18 percent, consistent with the assumption used in the previous *Supply Mix Advice Report* and confirmed by more recent studies.[5]

Studies were performed by the IESO at the OPA's request using General Electric's Multi-Area Reliability Simulation (GE MARS) model (see Appendix B) to determine whether or not the 18 percent reserve margin was sufficient to meet the generation adequacy criterion of the Northeast Power Coordinating Council (NPCC). Detailed simulations were performed for the years 2008, 2010, 2013, 2016 and 2020. These years were chosen to represent a range of supply mix assumptions. Results of the MARS analysis indicate a range of required reserve levels.

The load forecast methodology and resource availability assumptions reflect the methodology recommended by the IESO in June 2006, namely, the accounting for summer peak by seasonal or monthly forecasting, and the decreased availability of hydroelectric resources at the time of the summer peak.

These reserve margins specifically cover generator forced outages and load forecast uncertainty due to weather. However, as discussed in Section 2.7, there are significant additional risks that the IPSP must recognize. These additional risks have been considered in developing the proposed coal replacement plan.

For the purpose of developing the Preliminary Plan, the OPA used a 17 percent reserve margin for the period 2008 to 2019, and 18 percent for 2020 and thereafter. The forecast and the required resources are shown in Figure 2.1.

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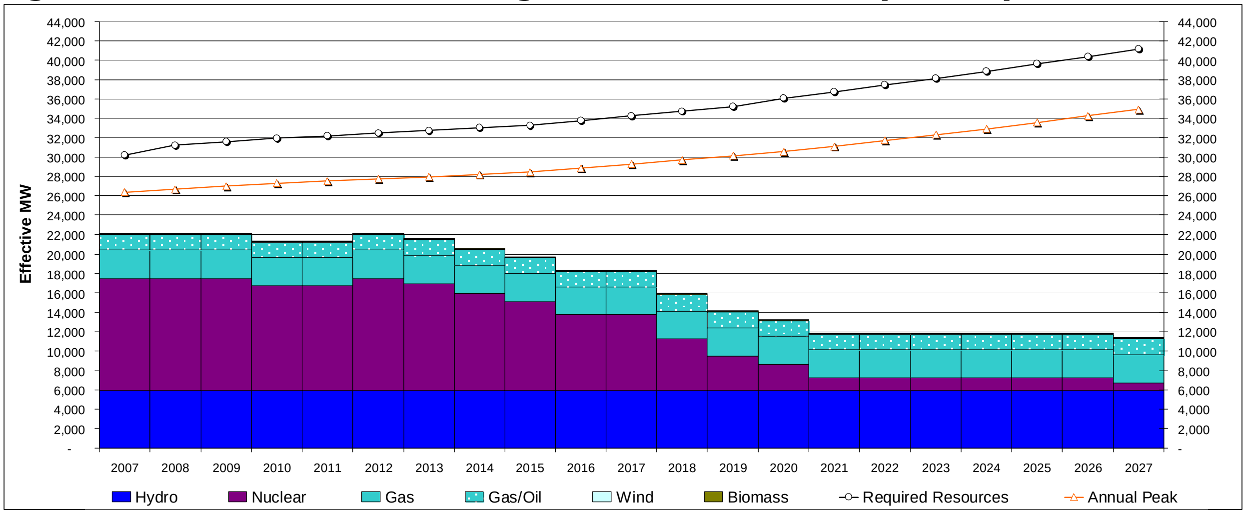
[4] For presentation purposes, transmission considerations are addressed after resource plans are defined (steps four to seven). This is a simplification – in practice, the resource and transmission aspects are developed together and iteratively.

[5] The system capacity that must be planned for can be divided into two categories: the amount required to meet forecast demand if all resources are assumed available at the time of the system peak demand, plus an additional amount that makes allowance for some resources not being available because of forced outages and specified other factors, such as higher than forecast demand. This additional amount of capacity is called the required planning reserve or reserve margin.

2.2 Step Two: Contribution of Existing Generation Resources

Figure 2.1 shows the required resources in relation to existing resources, excluding coal-fired generation, as presented in the supply resources discussion paper. The dominant characteristic is the substantial reduction in nuclear generation as units reach their end-of-life.

Figure 2.1 – Contribution of Existing Generation Resources (No Coal)



Source: OPA

The resources shown in Figure 2.1 include Lennox GS (2100 MW oil/gas), which is assumed to remain in service throughout the period covered by the Preliminary Plan. Many of the current resources are operating under commercial and regulatory agreements that may change or terminate over the plan period (for example, non-utility generation (NUG) facilities or Lennox). Lennox is currently required to be in service for reliability reasons. If reliability can be met by other resources, Ontario Power Generation (OPG) has indicated that operation of the station may be discontinued for economic reasons. The station is on a reliability "must-run" contract at this time.

The existing resources, even with assumptions of continued operation of the oil/gas component, are insufficient to meet requirements, with the gap growing substantially after 2013.

2.3 Step Three: Contribution of Committed Resources

For supply resources, the term "committed" refers to resources not yet in service, but which are proceeding on the basis of a signed procurement contract, or an award in response to a request for proposal (RFP) for new resources.

As outlined in Table 2.1, these committed supply resources represent approximately 6,800 MW of installed capacity (6,000 MW of effective capacity).[6]

Table 2.2 indicates that gas-fired generation represents 63 percent of the committed supply resources, and nuclear generation and renewable resources represent 22 percent and 15 percent, respectively.

Successful implementation of committed resources in the near term will be critical. These resources would represent nearly 22 percent of Ontario's existing installed generation capacity. Successful implementation will include ensuring resources are placed in service on time and that risk is managed. The OPA and IESO will continue to monitor the progress of these developments.

Table 2.1 – Committed Supply Resources (MW)

Committed Project	Installed MW
RES1 Hydro Umbata Falls	23
RES1 Trail Road Landfill	5
RES2 Island Falls	20
RES2 Kingsbridge 2	159
RES2 Ripley	76
RES2 KEPA	101
RES2 Prince 2	90
RES2 Leader A	101
RES2 Leader B	99
RES2 Melanchton 2	132
RES2 Wolfe Island	198
CES St. Clair	570
CES Greenfield	1005
CES Greenfield South	280
ACES Goreway Power	860
Portlands Energy Centre	550
CHP Great Northern Tri-Gen Facility	12
CHP East Windsor Cogeneration Centre	84
CHP Durham College CHP District Energy Project	2
CHP Thorold Cogeneration Project	236
CHP Countryside London Cogeneration Facility	12
CHP Algoma Energy By-Product Cogeneration Facility	63
CHP Warden Energy Centre CHP	5
Bruce 1& 2	1500
GTA West	600
Total	6,783

Source: OPA

[6] Installed capacity is the maximum power that can be produced (nameplate capacity). Effective capacity refers to the expected contribution of that resource in meeting the annual system peak demand. In case of an intermittent resource, such as wind power, the difference can be substantial – the Preliminary Plan considers only 17 percent of installed wind power capacity to be effective capacity. In the case of hydroelectric resources, the effective capacity varies by river system, and overall is in the range of 75 percent of installed capacity.

Table 2.2 – Committed Supply Resources (Percent by Type)

	Installed MW	% of Total Committed Resources
Renewable Resources	1,003	15
Gas	4,279	63
Nuclear	1,500	22
Total	6,783	100%

Source: OPA

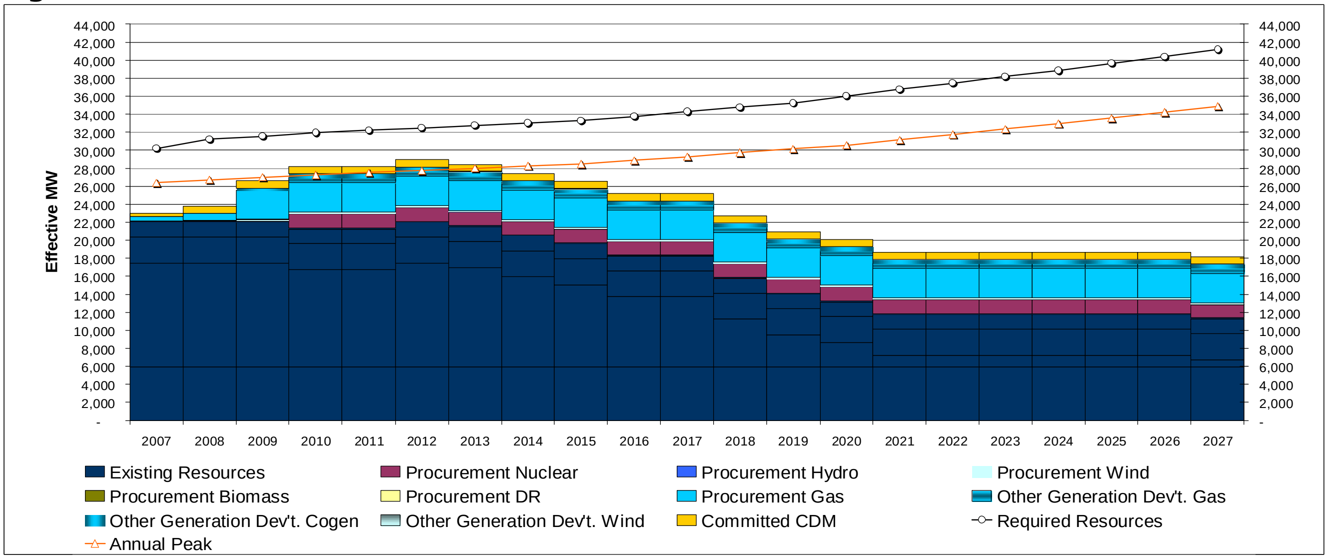
CDM resources are different from supply resources regarding the nature of commitment, typically being committed by program rather than by individual project. For present purposes, we include as committed CDM those initiatives currently awarded plus initiatives that have been launched or in development, as shown in Table 2.3.

Table 2.3 – Committed CDM Resources (MW)

	Description	MW	Status as of August 31, 2006
CES Loblaw Demand Response		10	Committed
York Regon Demand Response		3	Committed
Residential	Every Kilowatt Counts (spring)	8.7	Launched
	Cool Savings Rebate Program	31	Launched
	Secondary Fridge Retirement Pilot	1.6	Launched
	Aboriginal ConservationInitiative Pilot	2.3	In development
	Every Kilowatt Counts (fall)	15	Launched
	Hot Savings Rebate Program	8	Launched
Commericial, Municipalities, Universities, Schools and Hospitals	Social Housing Phase 1	10	Launched
	Low-Income Single Family	1.3	Launched
	Affordable Housing Program Phase 1	0.2	In development
	Low-Income Multiple Unit Residential Building	TBD	In development
	Colleges Secretariat	TBD	Launched
	Municipal Lighting Program	TBD	In development
	Energy Efficiency Contractors Network	TBD	Launched
Toronto	Building Owners and Managers Association	150	In development
	City of Toronto	90	In development
	Toronto Hydro	90	In development
Industrial & Agricultural	Demand Response Program	250	Launched
	Agricultural Program	2	Research underway
	Capability Building-Demand Response	125	In development
Total CDM Resources		798 MW	

Source: Chief Energy Conservation Officer, Annual Report 2006

Figure 2.2 – Contribution of Committed Resources



Source: OPA

2.4 Step Four: Contribution of New CDM Resources

CDM resources are conceptually the first new resources considered in developing the resource portfolio. They are cost effective by design; only CDM having a lower cost than new generation is considered for inclusion in the plan. CDM also has environmental performance advantages.

The CDM paper (#3) explained our three-pronged approach. The first is procuring resources to meet the 2010 targets in the ministerial directive. The second and third are building market capabilities and a culture of conservation over time, such that a transformed marketplace will deliver most of the demand reduction to meet the target for 2025. Market transformation means a reduction in market barriers over time due to an intervention. It is evidenced by a set of market effects that last after the intervention has been withdrawn, reduced or changed.

Our approach relies on partnerships with local distribution companies (LDCs) and a wide variety of other partners and participants in conservation. The OPA will be leveraging existing delivery capabilities to the greatest extent possible. We are also counting on changes to energy-related codes and standards to drive gains in energy efficiency, and metering and pricing changes to drive gains in demand management efficiency.

As discussed in the CDM paper (#3), a number of approaches have been used to establish the preliminary estimates of potential demand reduction and energy savings for each of seven CDM classes: reduced use, energy efficiency, time-of-use pricing, demand response, fuel switching, cogeneration and qualifying renewable resources. Economic potential was defined using the Total Resource Cost (TRC) test prescribed by the OEB. Achievable potential, which is a subset of economic potential, was estimated under a status quo policy assumption (low estimate) and an aggressive CDM policy assumption (high estimate). For each CDM category, we selected an estimate between the low and high, reflecting our interpretation of the assumptions in the aggressive scenario. The results are, in total, somewhat higher than targets set by the ministerial directive.

The amounts of CDM included in this plan, like the amounts of other resources, represent a best estimate at this point in time. We do not regard the government's CDM targets, or those in this plan, as "caps". Experience over the next period will inform future estimates and these will be recognized in future IPSPs by changing the CDM plan.

We expect, nevertheless, that it will be a challenge for Ontario to deliver the near-term amount of CDM included in the plan. CDM programming and delivery capability has been largely dismantled for the past 15 years and it is just restarting. This speaks to the feasibility of ramping up to levels above what is now contemplated. We must recognize that enhancing CDM capability, creating a culture of conservation and transforming the market will take time.

Most of the CDM savings are directly related to changes to equipment efficiency standards and the *Ontario Building Code*. These changes are starting to be put in place and will ramp up to yield the savings identified in the analysis of CDM potential, particularly in the long term.

The schedule for the implementation of these equipment efficiency standards and building code changes will have a significant impact on the CDM potential. Furthermore, these changes will have a long-term impact, and the full effect of these changes will be recognized once we have established a schedule for their implementation.

The OPA plans to implement an effective evaluation, monitoring and verification (EM&V) program to ensure that CDM savings are long-lasting and reliable. The data from such a program will become available in due course and will provide the basis for adjusting CDM programs.

Figure 2.3 shows the cumulative peak savings by CDM towards the government targets for CDM. Figure 2.4 does the same for energy. Figure 2.5 shows the planned contribution of new CDM resources in relation to other resources. Further details are summarized in Table 2.4.[7]

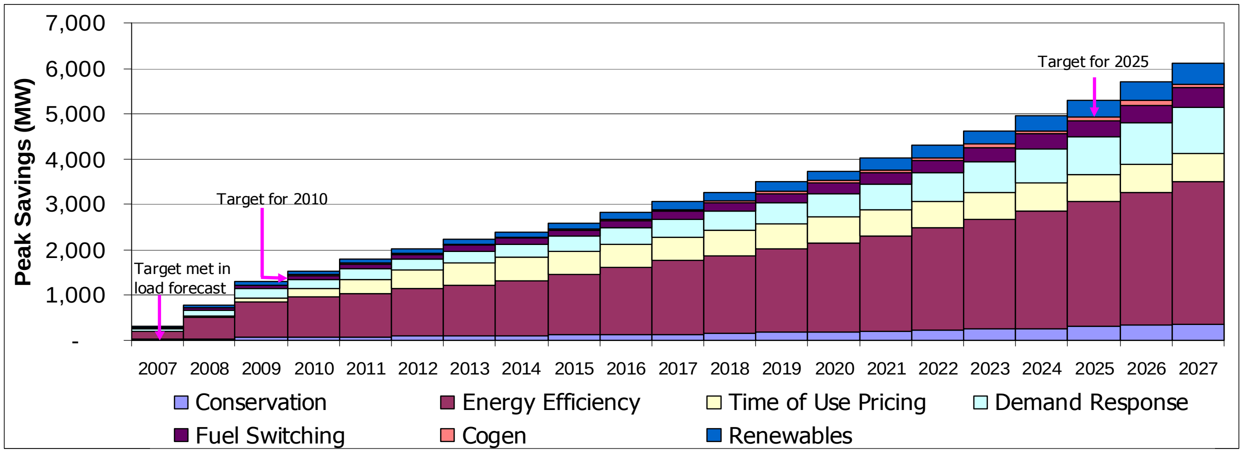
The 1,350 MW target for 2007 is mostly achieved, as reported by the Chief Energy Conservation Officer's (CECO) 2006 report. That target is incorporated here as part of the load forecast, not as new resources.[8] The additional CDM planned for 2008-2027 is 6,100 MW, for a total over the period of 7,450 MW. Overall, CDM is expected to provide approximately 6,100 MW of peak reduction by 2027, and 22 TWh of energy savings.

It should be recognized that the CDM values summarized below reflect a snapshot of analysis that is still evolving (as of November 2, 2006), and that further analysis and revision is expected. It is anticipated that revisions will be relatively minor and that they will not affect the overall conclusions of the analysis summarized below.

[7] The demand management category is shown as comprising time-of-use pricing and demand response. The self generation category is shown as comprising cogeneration and qualifying small renewable resources.

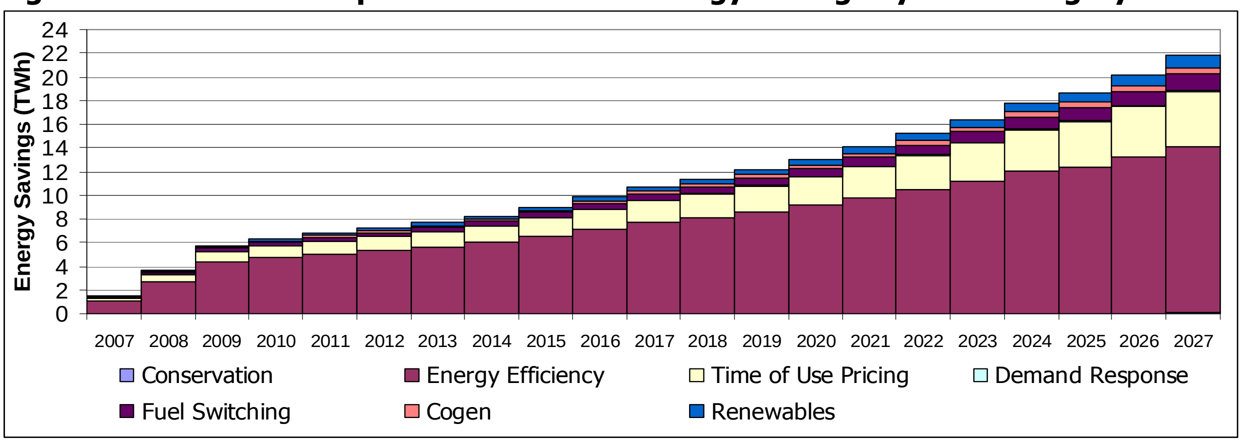
[8] CDM resources up to 2007 are reflected in the load forecast, that is, the forecast load is reduced from what it would otherwise be.

Figure 2.3 – CDM Assumptions: Cumulative Peak Savings by CDM Category



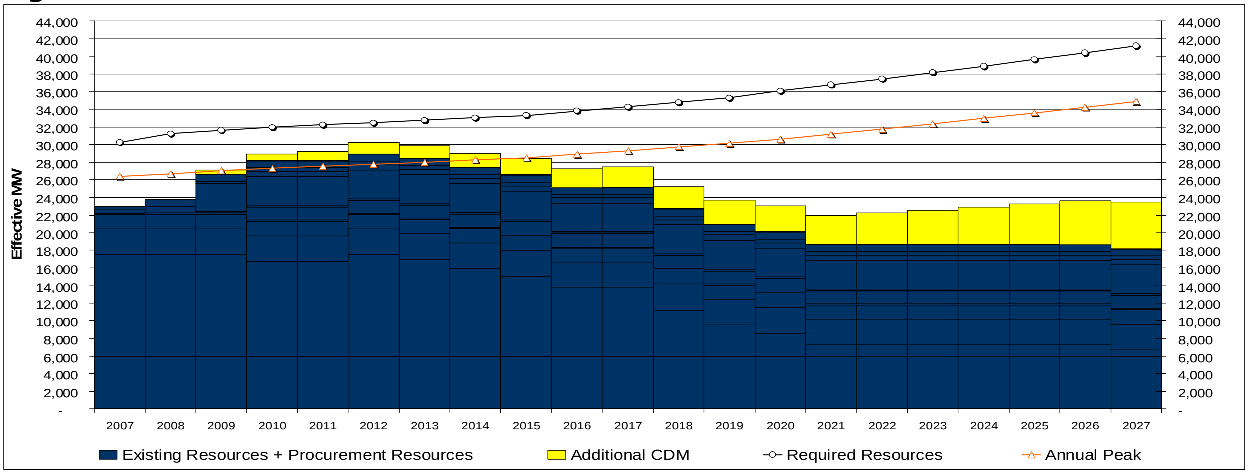
Note: Includes committed and new resources.
Source: OPA

Figure 2.4 – CDM Assumptions: Cumulative Energy Savings by CDM Category



Note: Includes committed and new resources.
Source: OPA

Figure 2.5 – Contribution of New CDM Resources



Source: OPA

Table 2.4 – CDM Assumptions: Peak and Energy Savings

	CDM Class	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Peak Savings (MW)	Conservation	18	30	70	77	85	91	99	107	117	129	142	153	169	186	204	225	247	272	299	329	362
	Energy Efficiency	199	497	795	874	962	1038	1122	1211	1332	1466	1612	1725	1846	1975	2113	2261	2419	2589	2750	2938	3139
	Time of Use Pricing	2	17	71	178	307	415	482	513	524	531	538	546	553	561	571	581	592	602	601	612	623
	Demand Response	48	120	193	212	233	252	272	293	323	355	391	430	473	520	572	629	692	761	837	921	1013
	Fuel Switching	20	50	80	89	99	107	117	127	141	155	172	188	207	228	252	277	305	334	360	396	436
	Cogen	4	11	17	19	21	23	25	27	29	32	35	39	43	47	52	57	63	69	75	82	90
	Renewables	19	47	76	83	91	99	107	115	131	150	171	188	207	227	250	275	302	333	375	415	458
	Total Peak Savings	**309**	**772**	**1302**	**1532**	**1798**	**2025**	**2223**	**2394**	**2598**	**2818**	**3061**	**3268**	**3497**	**3743**	**4013**	**4305**	**4620**	**4960**	**5297**	**5693**	**6121**
Energy Savings (TWh)	Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Energy Efficiency	1	3	4	5	5	5	6	6	7	7	8	8	9	9	10	10	11	12	12	13	14
	Time of Use Pricing	0	1	1	1	1	1	1	1	2	2	2	2	2	2	3	3	3	4	4	4	5
	Demand Response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Fuel Switching	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1
	Cogen	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
	Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1
	Total Energy Savings	**1**	**4**	**6**	**6**	**7**	**7**	**8**	**8**	**9**	**10**	**11**	**11**	**12**	**13**	**14**	**15**	**16**	**18**	**19**	**20**	**22**

Notes: Includes committed and new resources. Target for 2025 is 4,950 MW (in addition to the 1,350 MW for 2007).
Source: OPA

Revisions will be released later in November as part of the OPA's stakeholder engagement on CDM.

2.5 Step Five: Contribution of New Renewable Resources

While the ministerial directive specifies an objective of 15,700 MW of renewable resources, the IPSP is left to specify the mix of the new renewable resources from the main candidate options of hydroelectric, wind power and bioenergy. This section refers to and builds on information on these three options that was given in the supply resources paper (#4), for the purpose of developing the Preliminary Plan.

As shown in Table 2.5, there is currently about 8,100 MW of installed renewable resource capacity in Ontario. Most of this capacity is hydroelectric, with the balance consisting of wind and bioenergy (biomass).

Table 2.5 – Existing Renewable Resources

Type	Existing Installed Renewable Capacity (MW)
Existing Hydroelectric	7,768
Existing Wind	305
Existing Biomass	70
Total Existing Renewable Resources	8,143

Source: OPA

In recent years, a number of procurements have been initiated for new renewable resources. Renewable resources that have been committed through these procurements, but which have not yet entered service, are summarized in Table 2.6. These committed resources amount to about 1,000 MW.

Table 2.6 – Committed Renewable Resources Not Yet in Service

Type	Committed Installed Renewable Capacity (MW)
Committed Hydroelectric	43
Committed Wind	955
Committed Biomass	5
Total Committed Renewable Resources	1,003

Source: OPA

In order to meet the renewable resources objective of 15,700 MW by 2025, there is a requirement for nearly 6,600 MW of new renewable resources in addition to those existing and already committed. Table 2.7 outlines the additional new renewable resources in the Preliminary Plan.

Table 2.7 – Additional New Renewable Resources in the Preliminary Plan

Type	Additional New Installed Renewable Capacity by 2025 (MW)
Additional New Hydroelectric	2,283
Additional New Wind	3,764
Additional New Biomass	781
Additional New Solar	40
Total Additional New Renewables	6,868

Source: OPA

The Preliminary Plan includes a total of 16,000 MW of renewable resources installed at 2025. As illustrated in

Table 2.8, this total consists of 8,100 MW of existing resources, 1,000 MW of committed and about 6,900 MW of additional new resources.

Table 2.8 – Total Renewable Resources in the Preliminary Plan at 2025

Type	Installed Renewable Capacity at 2025 (MW)
Existing	8,143
Committed	1,003
Additional New	6,863
Total	16,009

Source: OPA

In the near term, the directive requires that Ontario's level of renewable resources must be 2,700 MW greater than the 2003 level by 2010. Based on the IESO's *10-Year Outlook* dated March 31, 2003, Ontario had 7,702 MW of installed renewable capacity in 2003. As shown in

Table 2.9, meeting the directive's target for 2010 will therefore require a total of 10,402 MW of installed renewable resources.

Table 2.9 – Renewable Resources Required to Meet 2010 Target

Type	(MW)
Existing Renewables in 2003[9]	7,702
Additional Renewables Required per Directive	2,700
Total Renewables Required for 2010	10,402

Source: OPA

Nearly 450 MW of renewable resources have been added in Ontario since 2003. Most of these new resources represent renewable procurements that have recently entered service. As outlined in

Table 2.10, about 1,250 MW of new renewable resources over and above the level of existing and committed renewables will be required to meet the 2010 target.

[9] IESO *10-Year Outlook*, p.5 (IMO_REP_0097v1.0)
http://www.ieso.ca/imoweb/pubs/marketReports/10YearOutlook_2004jan.pdf

Table 2.10 – Required Renewable Resources in 2010

Type	(MW)
Existing Renewable Resources in 2003	7,702
Existing Renewable Resources in 2006	8,143
Committed Renewable Resources Expected by 2010	1,003
Existing + Committed Renewable Resources by 2010	9,146
Total Renewable Resources Required for 2010	10,402
Additional Renewable Resources Required to Meet 2010 Target	1,256

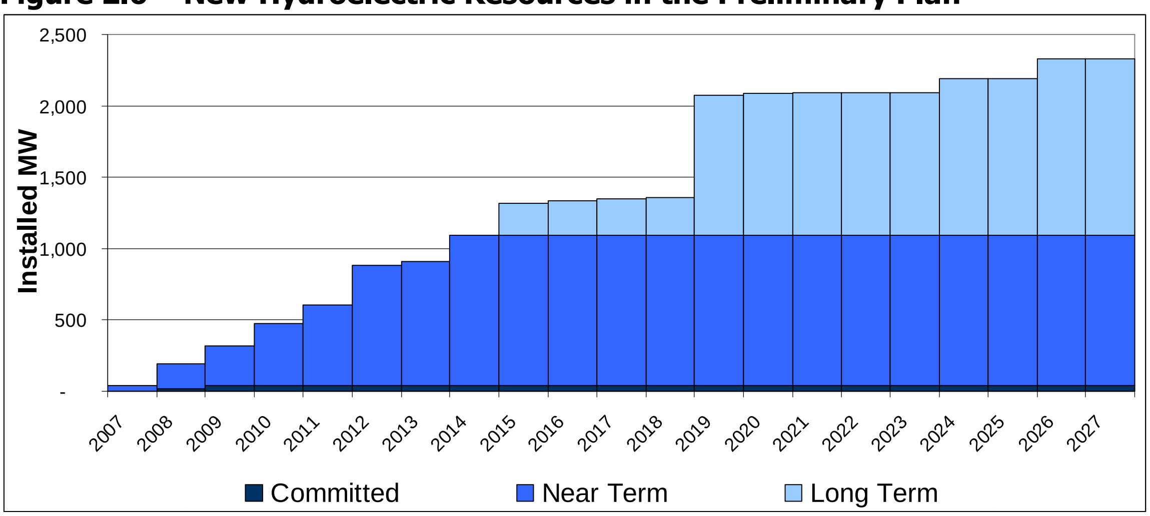
Source: OPA

2.5.1 New Hydroelectric Resources

New hydroelectric potential was presented in the supply resources paper (#4).

The cost range for development of the near-term (to 2015) hydroelectric potential is judged to be in the range of 3 to 7 cents per kWh. This would cover rehabilitation projects, efficiency upgrades, the Niagara Tunnel and developments, and redevelopments such as the Lower Mattagami River. There are potential developments at greenfield (new) sites in northern Ontario that are estimated to be in the range of 8 to 10 cents per kWh. Such hydroelectric developments, if they can be developed at the cost estimates given here, will be cost-effective. These new hydroelectric resources are, therefore, included on the basis of earliest possible in-service date, as shown in Figure 2.6.

Figure 2.6 – New Hydroelectric Resources in the Preliminary Plan



Source: OPA

In total, the Preliminary Plan assumes the addition of approximately 2,300 MW of new hydroelectric resources over the next 20 years. These new hydroelectric resources include all near-term hydroelectric potential identified in the supply resources discussion paper and, in the longer term, all future hydroelectric potential identified south of the Albany River.

New hydroelectric additions are assumed to enter service consistent with the projected in-service date estimates summarized in section 3.1 of the supply resources paper. All identified domestic hydroelectric potential until about 2020 is included in the Preliminary Plan. The early-to-middle periods of the Preliminary Plan see a tight resource balance, and the successful implementation of a large number of individual projects is essential for adequacy. Hydroelectric potential identified to be feasible within these periods is included both to support overall adequacy and to help meet short-term renewable resource targets. Hydroelectric resources within these periods can be accommodated without major interregional transmission enhancements.

Hydroelectric developments during these periods are also seen as important contributors of energy, particularly during the period where a substantial portion of Ontario's existing nuclear resources will enter refurbishment outage. Hydroelectric resources are also expected to support incremental system operability requirements associated with increasing penetrations of wind power on the Ontario system.

At around 2019, the Preliminary Plan includes hydroelectric resources along the Moose River Basin. These additional resources trigger major enhancement of the north-south transmission interface and open up the potential for additional renewable development in the region.

Hydroelectric power is a mature, long lasting, reliable, flexible and efficient technology, which has not been overtaken by invention over time, and with which there is considerable experience in Ontario. While hydroelectric power typically requires sizeable up-front capital investments, its long life span and relatively low cost fuel make it an attractive candidate for the long term. Initial planning-level assessments suggest the cost of new hydroelectric potential in the province is competitive with other renewable options.

The Albany River continues to offer Ontario a potential future resource. At present, partial development is estimated to represent 2.4 TWh of annual energy and nearly 900 MW of capacity. Community acceptance of the estimate is not established at this time. Future plans will be informed by additional feasibility assessments.

2.5.2 New Wind Resources

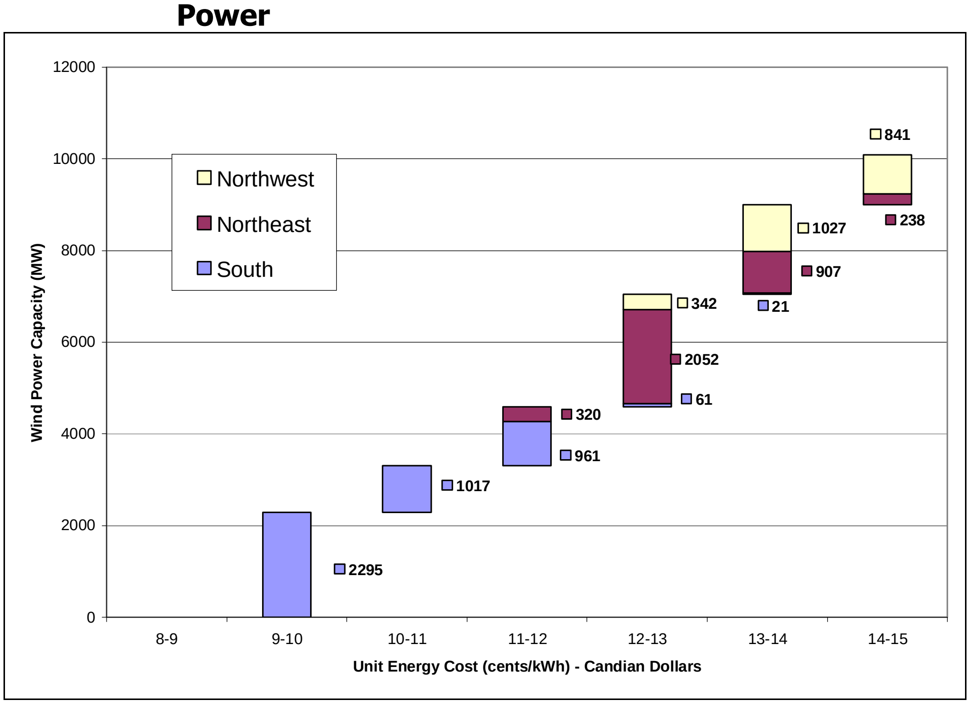
Wind power unit costs, by location, were discussed in the supply resources paper (#4), which concluded that 5,000 MW is a prudent level to include in the current plan. This would consist of 305 MW of currently installed capacity, nearly 1,000 MW currently under signed procurement contracts, plus an additional 3,700 MW yet to be developed. To assess these resources on an integrated basis, bulk transmission upgrade costs must be added to the wind energy costs, as discussed in the supply resources discussion paper. This is required to give the "all-in" levelized unit energy costs (LUEC) as shown in Figure 2.7.

Figure 2.7 illustrates the relative economics of all the potential wind resources in Ontario identified by the Helimax study by location when the bulk transmission costs are included.[10] The least expensive wind resources are seen to be in southern Ontario, closer to load centres and existing transmission infrastructure. Southern Ontario is the most cost effective location and consists of about 4,000 MW of wind power. Beyond this level, the opportunities are in the northeastern and northwestern parts of Ontario.

For the bulk transmission, generally, a large development triggers a need for a new transmission line. For this "all in" cost analysis, the cost of a new bulk transmission line would be allocated to the wind development's proportion of the line's capacity.

Although the potential for wind development in southern Ontario is significant, like any other power project, future wind projects will be subject to implementation risk, especially in southern Ontario. Southern wind is generally the most cost effective, but, because of these implementation risks, the Preliminary Plan provides a number of other wind locations to be developed in northern Ontario as well. Developing wind sites in northern Ontario takes into consideration a number of other factors, such as reliability, transmission availability and geographic diversity.

Figure 2.7 – All-In Levelized Unit Energy Cost (LUEC) for Wind Power



Note: Includes bulk transmission costs.
Source: OPA

[10] This study was performed by OPA. See Supply Resources discussion paper, pages 34-41.

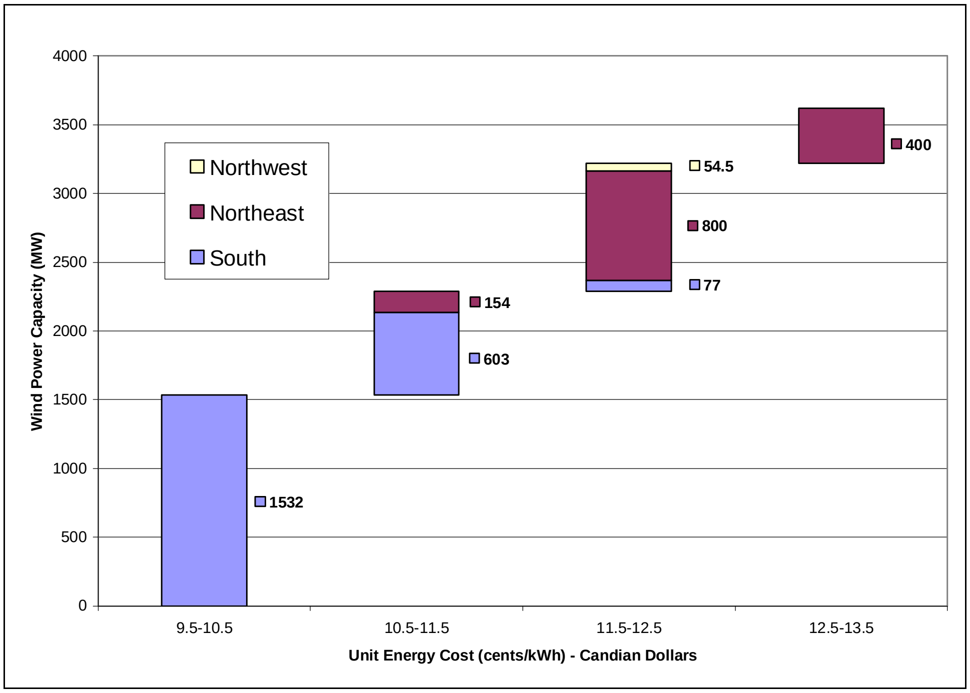
In the period up to about 2015, the Preliminary Plan assumes wind development will occur in southern Ontario, an area where transmission is available. It is assumed that wind power development between approximately 2015 and 2019 will be supported by enabling transmission enhancements around the Bruce Peninsula. Further wind development in the northeast will be supported after 2019 by the enhancement of the north-south interface. Enhancement of this interface is assumed in the Preliminary Plan as a means of enabling hydroelectric development along the Moose River Basin.

Like other power projects,we recognize that future wind projects will be subject to implementation uncertainties. As discussed above, the Preliminary Plan provides for a number of potential locations for future wind developments.

Considerable wind power potential also exists in northwestern Ontario. However, the extent to which this potential can be incorporated into Ontario's system at this time is limited by transfer limitations (the maximum allowable power flows) of the east-west tie. In addition, northwestern wind potential is not as cost effective as in the other regions. Future investment in major enhancements to the east-west tie may be triggered by resource development in the northwest and/or a large hydroelectric purchase from Manitoba. If this were to occur, it would be possible to integrate more of the northwest's wind power potential.

As discussed above, the Preliminary Plan provides a number of potential locations for future wind developments. Figure 2.8 shows the "all-in" LUEC for wind sites that are in the Preliminary Plan.

Figure 2.8 – All-in LUEC for New Wind Power in the Preliminary Plan



Note: Includes bulk transmission costs.
Source: OPA

Figure 2.8 illustrates the diversity of the new wind resources being developed in Ontario, and the relative economics of its potential. Some northern Ontario wind developments are included to enhance geographic diversity.

Ontario currently has limited operating experience with large amounts of wind power. This level of experience will necessarily grow as more wind projects are brought on line. Initial assessment of the operational impacts (e.g., impacts on regulation, load-following and operating reserve requirements) of large amounts of wind power in Ontario suggests the impacts are small-to-moderate with penetrations of up to 5,000 MW. Ongoing assessment of the performance of wind power projects in Ontario will help ensure that future plans adequately assess the capacity value of wind and provide for any incremental system requirements associated with increasing wind penetration.

2.5.3 New Bioenergy Resources

The Preliminary Plan assumes 780 MW of capacity from new bioenergy resources will be developed over the course of the 20-year planning period. Of this total, 120 MW is assumed to come from municipal sources, such as landfill gas, anaerobic digestion of municipal organic waste and wastewater treatment by-products. These resources are assumed to be located close to urban areas in southern Ontario. From the forestry sector, it is assumed that 200 MW of bioenergy will be available from the conversion of the Atikokan generating station to wood fuel, peat or a combination of biofuels. Another 185 MW is assumed to come from forest resources in northeast Ontario. Agricultural resources and off-farm residues, primarily in rural southern Ontario, will contribute 276 MW of new bioenergy capacity. The agriculture-based bioenergy resources are assumed to be mostly small, distributed resources, although some developments may occur in northern agricultural areas, such as Thunder Bay.

Table 2.11 – New Bioenergy Capacity

	Planning Assumption: Installed Capacity (MW)			
	2008 – 2010	2011 – 2015	2016 - 2027	Total
Municipal Waste	70	45	5	120
Forestry	60	60	65	185
Atikokan		200		200
Agriculture	100	96	80	276
Total	230	401	150	781

Source: Source: OPA

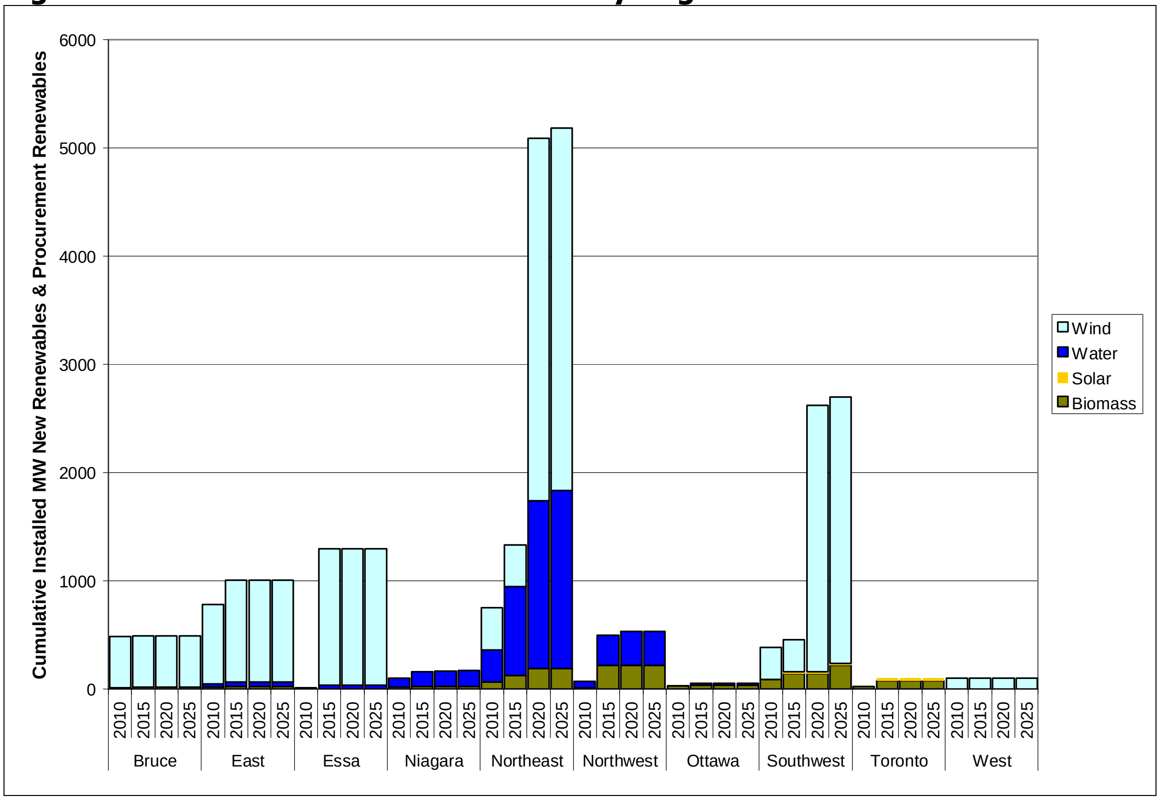
2.5.4 Hydroelectric Imports

There are opportunities to purchase hydroelectric imports from Quebec, Labrador and Manitoba. Likely in-service dates for these imports are in the 2010-2015 timeframe, at the earliest. Any firm purchase is contingent on finding mutually-acceptable terms and conditions. The Preliminary Plan includes 500 MW of short-term imports in the period 2014-2019, which is not contracted for at this time.

2.5.5 Renewable Resources in the Preliminary Plan

Figure 2.9 illustrates the location of new renewable resources assumed in the Preliminary Plan. In the case of hydroelectric resources, assumed locations are determined by the physical locations of the identified hydroelectric resources. Wind is assumed to be developed as outlined earlier in section 2.5 of this paper. It will be developed where there exists a favourable combination of a good wind resource, proximity and access to transmission, and available land.

Figure 2.9 – New Renewable Resources by Region



Source: OPA

As discussed earlier, it is assumed that wind development will begin in southern Ontario, and will then proceed northward as enabling transmission is developed.[11] The location of assumed bioenergy resources is largely driven by proximity to biomass fuel. For example, bioenergy from municipal waste is assumed to occur in larger urbanized areas; forestry bioenergy is assumed to occur where forestry materials are available, such as in the northwest; and agricultural bioenergy is assumed to occur in farming areas across the province. It is recognized, however, that transportation of fuel across large distances may be a possibility.

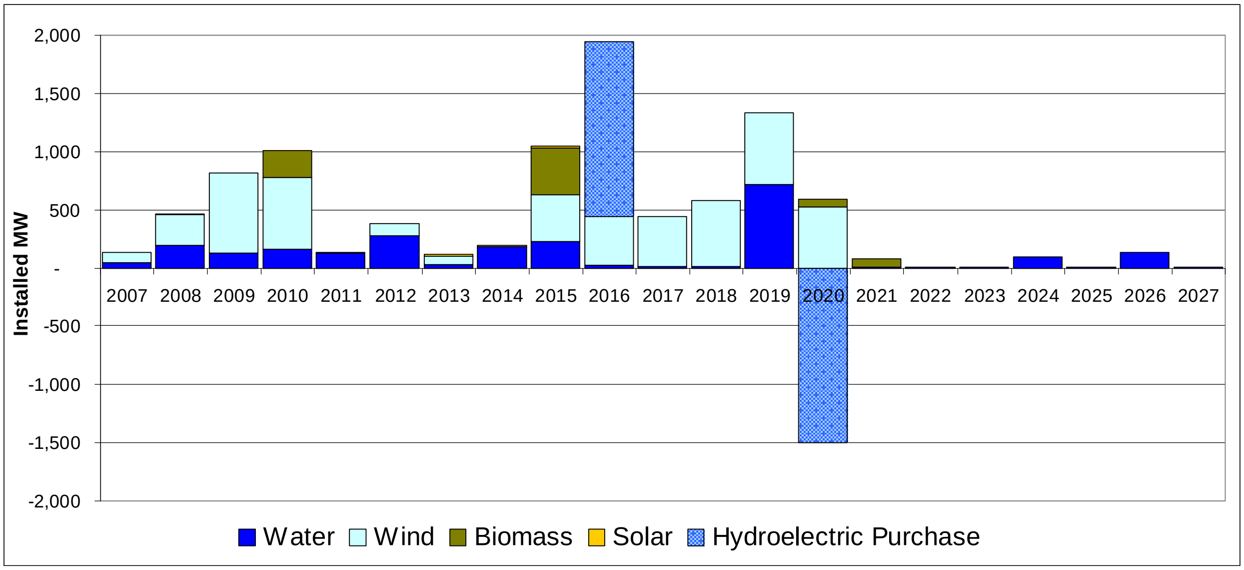
Figure 2.10 and Figure 2.11 illustrate the renewable capacity additions assumed in the Preliminary Plan. These additions include both the committed and near-term resources illustrated in Figure 2.2, as well as the additional renewable resources illustrated in Figure 2.12. A total of nearly 7,900 MW of installed new renewable resources is added over the course of the Preliminary Plan. On an effective capacity basis, this translates to approximately 3,300 MW.

Including existing renewable resources, the Preliminary Plan has Ontario's total renewable fleet at 2027, consisting of 10,000 MW of hydroelectric resources, 5,000 MW of wind power, 850 MW of bioenergy and 40 MW of solar power, for a cumulative resources, total of approximately 16,000 MW of installed renewable resources. This is more than double the 2003 level of installed renewable capacity.

[11] This part is developed further in Section 2.8, Transmission Integration.

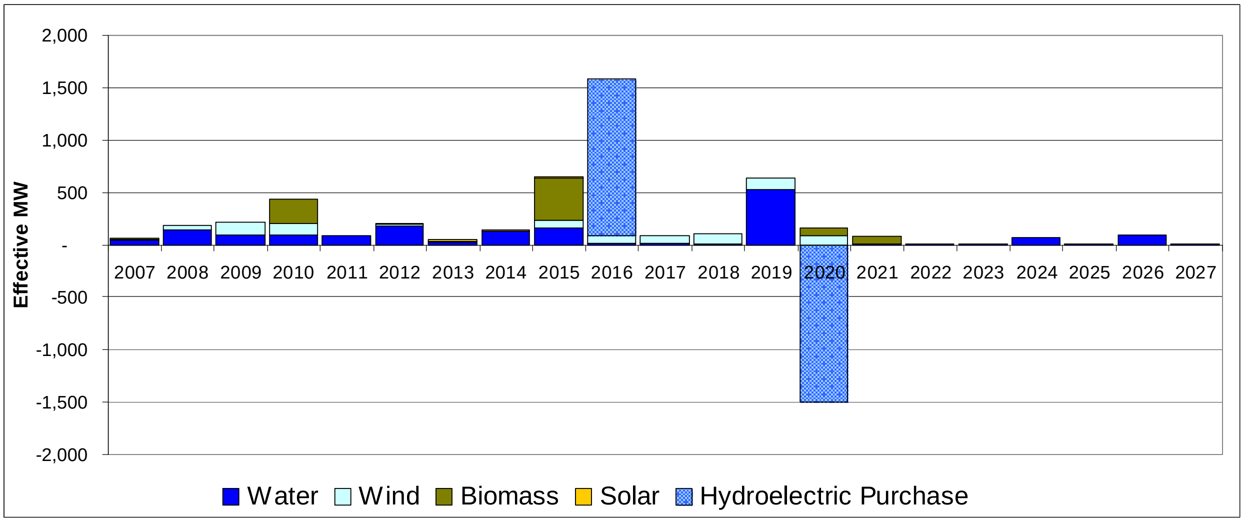
Figure 2.13 and Figure 2.14 illustrate renewable additions on a cumulative basis, both in installed and effective terms. A short-term hydroelectric purchase is assumed in 2016 through 2019, with potential for a longer-term commitment. The figures below show the purchase being short-term in nature, and thus indicate a decline in total waterpower resources from 2019 to 2020.

Figure 2.10 – Renewable Resource Additions – Installed Capacity Basis



Includes Committed resources.
Source: OPA

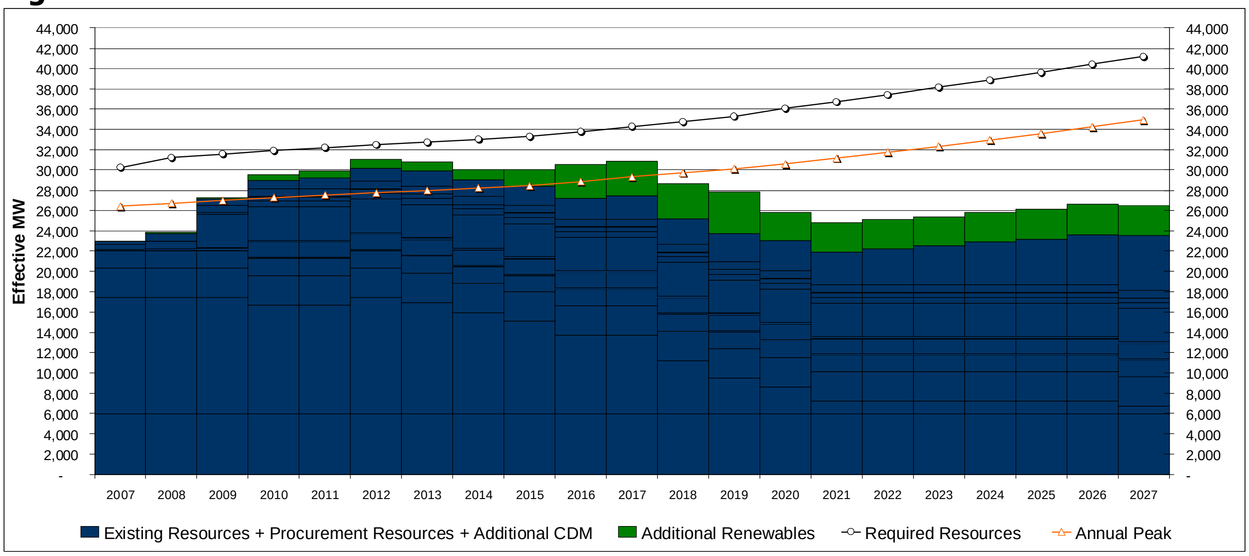
Figure 2.11 – Renewable Resource Additions – Effective Capacity Basis



Includes committed resources.
Source: OPA

Figure 2.12 illustrates the contribution of new renewable resources over and above the committed and nea r-term renewable amounts illustrated in Figure 2.2. On an installed basis, the new renewable resources consist of 2,200 MW of additional waterpower, approximately 3,700 MW of additional wind power, 780 MW of new bioenergy and a small amount of solar power. The renewable resources are illustrated below on an *effective* capacity basis, accounting for hydroelectric availability as well as the availability of wind power around the time of the annual peak.

Figure 2.12 – Contribution of New Renewable Resources



Source: OPA

Assumptions around the types, amounts and timing of new renewable resource additions included in the Preliminary Plan have been made with reference to the six sustainability criteria explained in section 1. The main feasibility considerations are development lead times and transmission availability. Reliability and flexibility are addressed by explicitly considering geographic diversity, fuel diversity and the operating characteristics of wind and hydroelectric generators. Costs are addressed in comparing prospective developments in different geographic locations, and both with and without the associated transmission requirements.

In developing the Preliminary Plan's program of wind additions, effort has been made to foster diverse geographic coverage, to develop wind over time in such a manner that enables learning by doing and provides for adaptation, and to provide for sufficient amounts of development to help reduce costs over time.

Initial assessment suggests that output variability of large amounts of wind power can be addressed significantly through geographic diversity of wind sites. This then increases the portion of installed capacity that can be considered effective capacity. Diversity is seen to support greater predictability of aggregate wind output, help lessen the likelihood of sudden disruptions in aggregate power output across the province, and help reduce the need for incremental balancing resources. As discussed above and later in section 2.8, new wind additions are assumed to span southern Ontario in the near to medium term, southwest Ontario in the medium term and northeast Ontario in the longer term, with potential in the northwest depending on transmission availability.

While wind power projects require relatively short lead-times (i.e., about three years from project development to commissioning), wind power additions in the Preliminary Plan are assumed to occur gradually over the course of the planning horizon, rather than all in the near term. This is judged to be prudent since, as mentioned above, Ontario's experience with large amounts of wind power is still nascent. While initial assessment suggests that operability impacts of penetrations up to 5,000 MW are modest, that this assessment is based on a limited number of observations occurring over a limited timeframe (i.e., one year's worth of data from a relatively small amount of wind towers and sites).

Experience with increasing levels of wind over time will help ensure that any planning and operating implications of increasing levels of wind power can be informed by the best possible "real life" information and experience. In addition, certain planned transmission enhancements that would promote geographic diversity, such as enabler lines in the Bruce Peninsula and the enhanced north-south interface, are expected to occur in both the medium- and long-term timeframes, respectively. The wind addition program assumed in the Preliminary Plan takes advantage of these planned enhancements.

During the development of the supply mix advice in 2005, the OPA heard from stakeholders that costs of wind power equipment could be reduced over time through the development of local manufacturing and/or assembly capability, and that a fairly sustained amount of annual wind additions is required in order to achieve this. The Preliminary Plan sees an addition of more than 300 MW of wind power per year between 2007 and 2020 (including committed wind projects). While some years see fewer additions and other years more, the intent has been to balance the considerations of geographic diversity and learning by doing and adapting by promoting a relatively steady and targeted stream of wind development in Ontario over the course of the planning period.

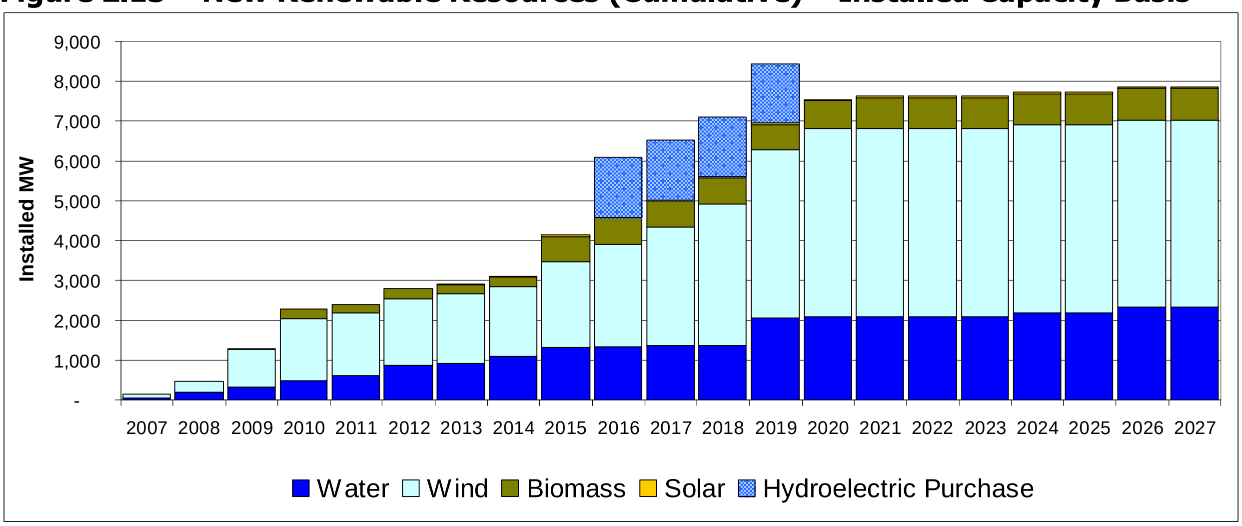
Bioenergy in the Preliminary Plan is assumed to stem from the municipal, agricultural and forestry sectors. Additional bioenergy potential is assumed from the conversion of the Atikokan generating station to a biomass-fuelled generator. Of all new renewable resources considered in the Preliminary Plan, bioenergy has perhaps the greatest degree of uncertainty as to potential, cost and feasibility. These issues are discussed more fully in section 3.4 of the supply resources paper (#4).

Bioenergy resources were included in the Preliminary Plan to help support reliability requirements, to help meet renewable resources targets, to assist in the replacement of Ontario's coal-fired fleet (in the case of Atikokan), to enhance diversity of renewable generation technologies in Ontario, to advance the development of distributed generation and combined heat and power (CHP), and as a potential way of supporting a number of interconnected societal issues, such as rural economic development and the management of municipal organic waste. It is expected that future power system plans will be informed by ongoing investigations into feasibility of Ontario's bioenergy resource potential.

Together, the renewable resources described above contribute to meeting the directed level of renewables by 2025, to enhancing the diversity of Ontario's resource mix and to improving the environmental performance of Ontario's electricity system. Significant potential also exists from renewable sources not discussed above, but which are considered as options in the Preliminary Plan. For example, opportunities exist for additional hydroelectric development along the Albany River beginning at about 2020, and perhaps on other rivers in the northern part of the province thereafter. Potential also exists for renewable purchases from outside of Ontario. Hydroelectric energy from Quebec represents up to 1,250 MW of near-term potential. In the medium and long term, there is potential for hydroelectric purchases from Manitoba and Labrador. Each of these could represent an additional 1,000 MW or more. The OPA will pursue these opportunities in view of learning more about them. Further study and discussion will help in determining the degree to which these are viable options for Ontario.

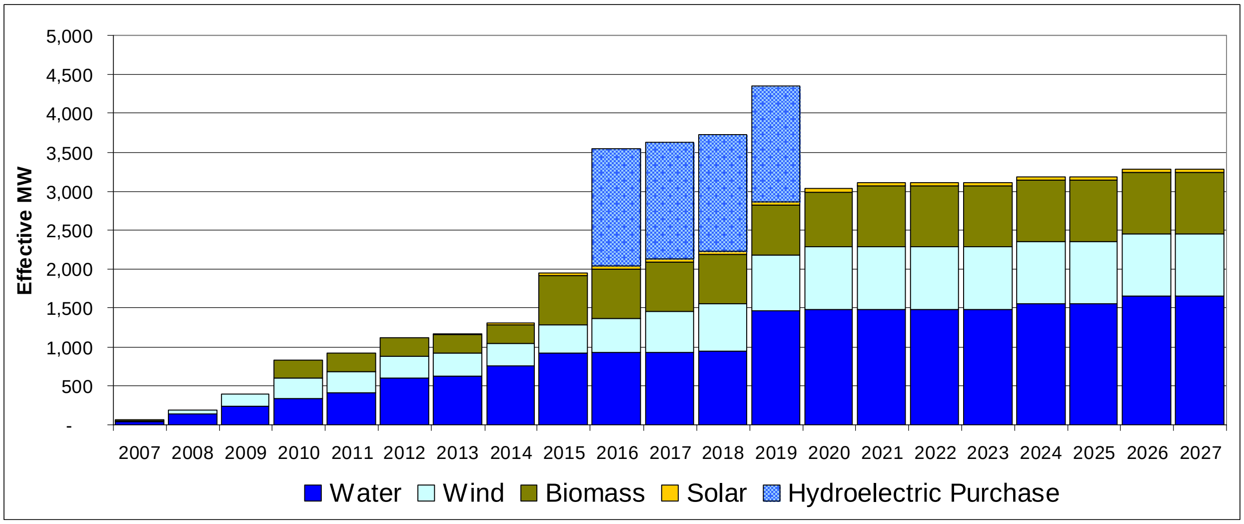
The renewable resources, by type and location, that are included in the Preliminary Plan are shown in Figure 2.11 and the following figures.

Figure 2.13 – New Renewable Resources (Cumulative) – Installed Capacity Basis



Includes committed resources.
Source: OPA

Figure 2.14 – New Renewable Resources (Cumulative) – Effective Capacity Basis



Includes committed resources.
Source: OPA

2.6 Step Six: Contribution of New Conventional Resources

This section presents considerations in determining the mix of conventional resources included in the Preliminary Plan.

2.6.1 Nuclear Resources

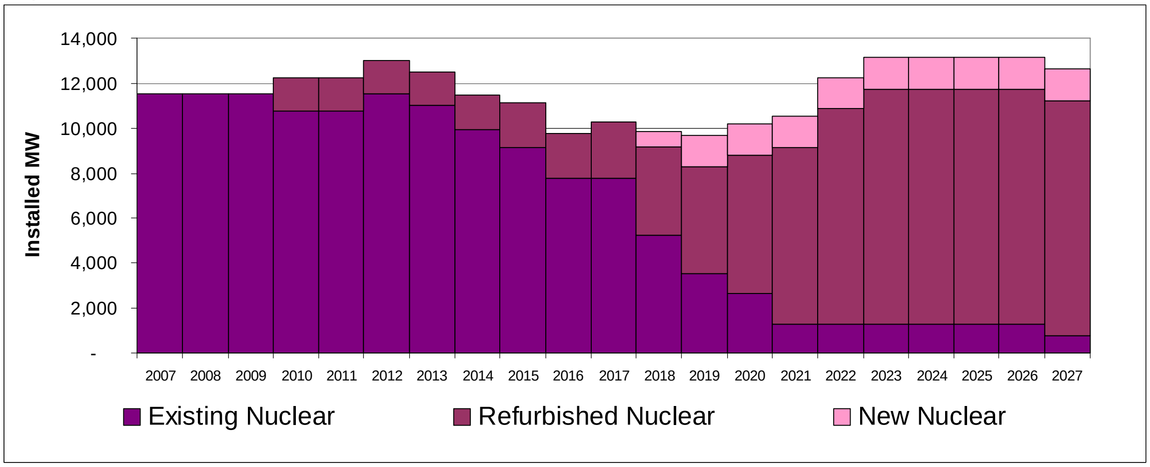
The nuclear resources included in the Preliminary Plan are shown in Figure 2.15. These resources include the refurbishment of most of Ontario's existing fleet, the re-start of two units that are not currently operating, plus the addition of about 1,400 MW to 2,800 MW of nuclear energy. Refurbishment assumptions (e.g., related to end-of-service lives, early indications of feasibility, availability of labour and materials, lead times, outage schedules) are based on discussions with Ontario's nuclear asset owners and operators.

For planning purposes, a set of representative long-term unit ratings was agreed to among the OPA and the nuclear asset owners and operators. These representative unit ratings are used in the Preliminary Plan, recognizing that Ontario's nuclear units may undergo various uprates and derates to their maximum continuous ratings over the course of the plan.

The refurbishment schedule illustrated in this section attempts to maximize nuclear availability over the planning period. By 2019, 1,400 MW of new nuclear capacity will be added, with potential for an additional 1,400 MW by 2027. The length of time required to develop new nuclear resources will depend on a number of variables, including timing of regulatory approvals and construction arrangements. While the Preliminary Plan includes new nuclear resources as of 2018, it is recognized that earlier in-service dates may be possible.

The Preliminary Plan assumes a total installed nuclear capacity of approximately 12,600 MW at 2027, with flexibility for up to 14,000 MW.

Figure 2.15 – Nuclear Resources



Source: OPA

The directive establishes a maximum of 14,000 MW of installed nuclear capacity over the planning period. It is recognized that Ontario's baseload mix must provide for adequate system operability, including during low load periods. Accordingly, the OPA is assessing the appropriate level and components of baseload resources over the course of the Preliminary Plan, taking into consideration changes in baseload requirements over time, existing baseload resources, retirements of existing baseload resources, expected additions of nuclear and non-nuclear baseload resources, as well as the potential for complementary technologies such as energy storage. In addition to refurbished and new nuclear resources, the Preliminary Plan sees the addition of substantial amounts of new wind power, hydroelectric resources, bioenergy, CHP, fuel cells and CDM.

Figure 2.15 demonstrates that the period between about 2016 and 2021will see a considerable reduction in the contribution from nuclear resources. For purposes of overall adequacy, it will be especially critical to manage and maximize nuclear availability during this period. Uncertainties will include longer than expected delays in refurbishment outages, while opportunities will include earlier than expected completion of refurbishment work.

In the period up to about 2016, as discussed in section 2.7, plans for refurbishment or retirement of Pickering B will have implications on transmission development in the eastern GTA, potentially requiring advancements of planned transmission reinforcements in the Oshawa area. In the Bruce/Southwest region, transmission will be required to incorporate the return of the two non-operating nuclear units at the Bruce facility.

2.6.2 Natural Gas-Fired Generation

There are approximately 7,000 MW of new gas-fired resources assumed in the Preliminary Plan, of that amount, about 4,300 MW reflects procurements either already committed or close to being committed. The latter includes the Clean Energy Supply (CES), Goreway, Portlands, CHP and GTA West procurements. Natural gas being planned for local area supply, transmission relief and voltage support accounts for 1,650 MW. Another 1,100 MW represents a combination of fuel cell technology, other distributed generation technology and additional CHP. Including existing gas/oil-fired resources, the Preliminary Plan would see 9,300 MW of installed gas/oil capacity by 2010, 11,600 MW by 2015, and nearly 12,000 MW by 2027.

Table 2.12 summarizes the new gas-fired projects in the Preliminary Plan.

Table 2.12 – New Natural Gas-Fired Additions in the Preliminary Plan

Status	Projects	MW
Committed (4,300 MW)	CES, Goreway, Portlands, CHP	3,700
	GTA West	600
Uncommitted (2,750 MW)	Local Area Supply /Transmission Relief	1,650
	Fuel Cell/Distributed Generation	500
	Rest of CHP	600
	Total New Gas	7,050

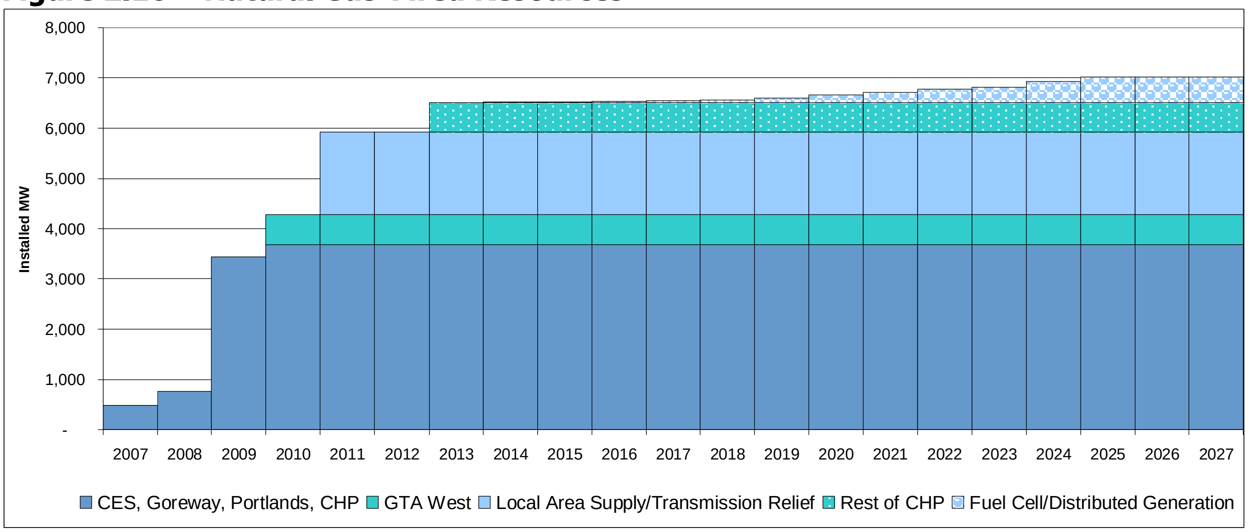
Source: OPA

In the *Supply Mix Advice Report* of December 2005, the OPA recommended that all future gas additions in Ontario be either high efficiency applications (such as CHP, cogeneration or fuel cells) or serve targeted purposes such as local area supply or transmission relief. All new natural gas projects (i.e., over and above committed projects) assumed in the Preliminary Plan are consistent with this recommendation. For example, 750 MW of new peaking gas-fired resources are being considered for addressing local area supply and transmission issues in southern Ontario. A further 900 MW of gas-fired generation is being contemplated for southwest GTA to relieve flows across bulk circuits and transformers in the area and to help support voltage across the GTA. The Preliminary Plan also assumes 1,100 MW of high efficiency gas-fuelled generation in the form of fuel cell or other efficient distributed gas generation technology and CHP.

In addition to serving the above purposes, the assumed gas-fired additions are expected to help support adequate response capability of Ontario's power system, for example, with respect to ramping capability and operating reserve. It is expected that such capabilities will be of particular importance as more variable renewable resources, such as wind power, are added to Ontario's resource mix.

The majority of new gas projects assumed in the Preliminary Plan would enter service by 2013. Aside from fuel cell technology, no other gas-based resources are assumed in the Preliminary Plan beyond 2013. Where possible, the Preliminary Plan has sought to minimize the extent of new gas-fired additions over the planning period. Alternatives to additional gas-fired generation assumed in the Preliminary Plan include energy storage (i.e., to provide fast-ramping intermediate, peaking and ancillary services), demand response, new peaking hydroelectric resources and hydroelectric purchases from outside of Ontario. It remains to be better understood whether resources such as bioenergy and fuel cells can also provide ramping capability (as opposed to running as baseload resources), the extent to which control features on wind installations can contribute to system flexibility and whether gasification will emerge in the future as a viable alternative. Future plans will reflect increased experience with these and other options.

Figure 2.16 – Natural Gas-Fired Resources



Source: OPA

2.6.3 Storage

As was discussed in the supply resources paper (#4), pumped generation storage (PGS) can be competitive with simple cycle natural gas-fired generation under conditions of low capital cost ($1,000/kW or less) and low cost of the pumped energy ($10/MWh or less). On the basis of paper #4, the plan includes 500 MW of new PGS in each of 2019 and 2020, assumed for planning purposes to be located in northeastern Ontario.

The potential role envisioned for storage in the Preliminary Plan is to support system operability by providing additional ramping capability, potentially providing additional ancillary services such as regulation, operating reserve, and black start capability, and to complement off-peak generation from renewable, nuclear and perhaps other resources.

2.6.4 Gasification

As was discussed in the supply resources paper (#4), 250 MW of generation from gasification is included in the Preliminary Plan as future potential. This would not come into service until 2018, allowing time for full commercial viability of this option to develop.

Gasification represents a potential hedge against future natural gas price uncertainty and volatility. As a still developing technology, it is not yet certain whether gasification would need to be operated in a baseload role, or as a more flexible intermediate and/or peaking resource. The experience of other jurisdictions currently exploring gasification will be instructive in this regard.

Gasification may not be acceptable to Ontarians without carbon sequestration. The potential for carbon sequestration in Ontario will need to be explored to gain better insight into the potential future prospects for the technology.[12]

2.6.5 Interconnection Support

The Preliminary Plan assumes 500 MW of interconnection support to be available at the time of the annual peak. It is assumed that a 500 MW planned outage occurs each year at that time. The IESO may recall such an outage if necessary. In the event the outage cannot be delayed or advanced, IESO Market Rules provide that the market participant must arrange for an equivalent amount of supply to cover the outage. The assumption of 500 MW of standing interconnection support reflects this equivalent amount of supply.

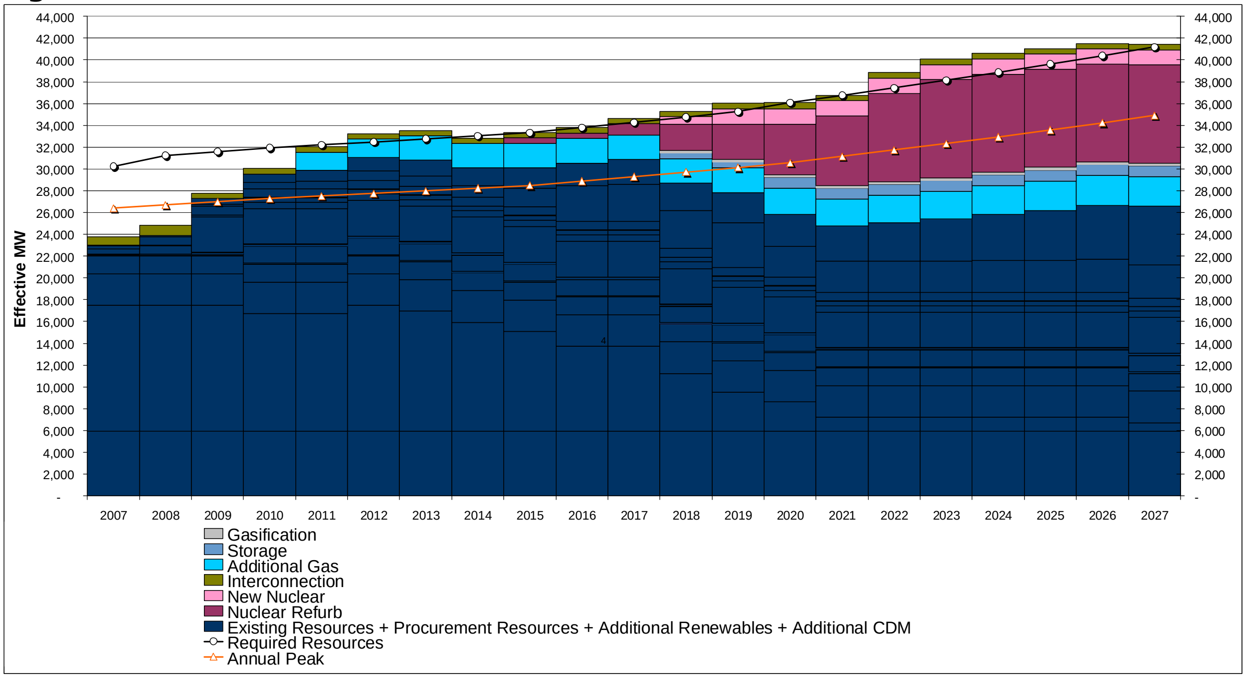
Interconnection support is used in the Preliminary Plan as a way to address short-term resource imbalances, and thus prevents the addition of small amounts of new resources that are not required later on. At times, more than 500 MW is assumed, but this is applied sparingly rather than as the norm. Ontario's actual interconnection capability is in the realm of 4,000 MW. Therefore, the assumption of 500 MW of interconnection support available at the time of annual peak is conservative.

2.6.6 Contribution from Conventional Resources

Figure 2.17 shows the mix of new conventional resources included in the Preliminary Plan in relation to requirements and the previously-discussed resources (no coal-fired ones). Additional resources will be needed to meet total resource requirements in the near term. The next section describes how the Preliminary Plan uses existing coal-fired resources as the primary means to achieve this. This is consistent with reliability and feasibility criteria.

[12] Carbon sequestration refers to preventing carbon dioxide that is produced in generating power from entering the atmosphere.

Figure 2.17 – Conventional Resources



Source: OPA

2.7 Step Seven: Contribution of Coal and the Coal Replacement Plan

This section describes the plan for coal replacement called for in the ministerial directive:

> *"Plan for coal-fired generation in Ontario to be replaced by cleaner sources in the earliest practical time frame that ensures adequate generating capacity and electric system reliability in Ontario. The OPA should work closely with the IESO to propose a schedule for the replacement of coal-fired generation, taking into account feasible in-service dates for replacement generation and necessary transmission infrastructure."*

As indicated in Figure 2.17, the resources in the Preliminary Plan described to date, without consideration of the existing coal-fired resources, do not meet minimum resource requirements in the period to 2011. As other resources were maximized in the short term, existing coal-fired generation represents a resource to meet the gap to 2011 to ensure adequate generating capacity and system reliability.

Considerations in Developing the Replacement Plan

The development of the replacement plan for the coal-fired generation facilities was based on the following key considerations:

- maximize options that can replace coal
- address uncertainties and ensure that system reliability can be maintained

- determine the earliest practical phase-out of coal, taking uncertainties into account
- explore the potential for use of emission reduction technology.

Examine Alternatives to the Use of Coal in the Short-Term

In developing the coal replacement plan, the OPA considered alternatives for accelerating the replacement of coal-fired generation units. The alternatives considered are in addition to the plan elements previously reviewed. We considered the contributions from CDM and renewable resources to be at the practical attainable level in the near term and therefore adding more is not feasible. The options considered include the following:

- **Increased use of natural gas.** Conversion of existing coal-fired boilers to gas-fired boilers involves the cost of burner tip replacement, the cost of new or expanded gas pipeline capacity, and the cost of natural gas. According to OPG, the conversion of existing boilers at Nanticoke to burn natural gas could cost in the range of $30 million to $50 million per unit ($240 million to $400 million for all eight units) and take about five years to complete. In addition, gas pipeline costs are likely to be in the order of $300 million to $350 million, resulting in a total conversion cost ranging from about $540 million to about $750 million. The fuel cost and low efficiency at Nanticoke will result in operating costs for generating electricity at close to $100 per MWh (close to the cost of Lennox GS). Putting these three factors together (lead time, cost and inefficiency) leads to this option not being recommended.

  Building new combined cycle gas turbine units would represent a higher efficiency solution than conversion of existing boilers, but has similar long lead-time requirements. The Preliminary Plan already includes a substantial amount of gas-fired generation, which is a challenge to implement. Much more new gas will result in the use of gas for baseload and intermediate load applications, and that is not consistent with public policy as reflected in the Minister's directive. If several thousand MW of new gas-fired capacity were built in the short term to replace coal, it would be surplus to the desired long-term generation mix. For these reasons, the increased use of natural gas is not considered to be a feasible alternative to the continued operation of coal-fired units for a limited period of time.

- **Electricity imports.** Opportunities for the import of clean energy should continue to be explored. Firm capacity imports could potentially enable coal replacement to proceed more quickly. When and if such arrangements are put in place, the coal replacement plan will be reviewed to assess the opportunities for advancement of coal replacement. The proposed 1,250 MW intertie (transmission connection) with Quebec has some potential in this regard.

Address Uncertainties and Ensure Reliability

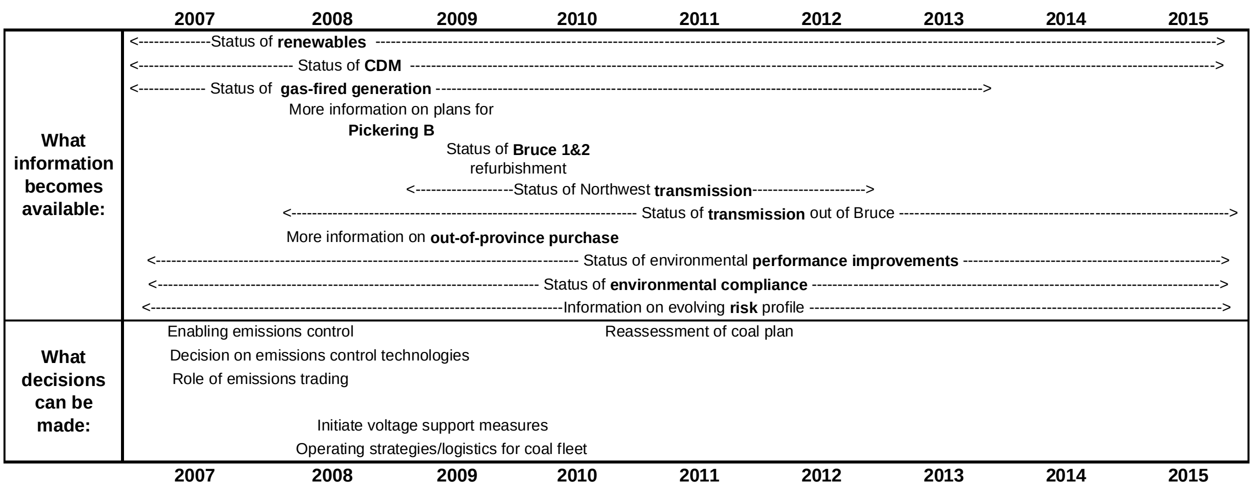
Factors related to ensuring system reliability include maintaining adequate system capacity, maintaining system security, both locally and provincially, and ensuring that the system remains operable at all times.

While the 1,200 MW Lakeview Generating Station was taken out of service in 2005, the remaining coal-fired generation remains a significant component of Ontario's electric system, with a current installed capacity of 6,434 MW (equivalent to 21 percent of the total installed capacity), and producing 30.9 TWh of electricity in 2005 (or 19 percent of the total electricity production). Coal-fired generation has historically contributed to meeting peak and intermediate demand, and reserve requirements. Replacing any of the remaining coal-fired generation represents a significant challenge during a period of transformation as Ontario's future electricity system takes shape.

As committed resources are built in the near term, and further new resources are committed, there will be continuous assessment of reliability as new information becomes available. The corresponding implications on planned requirements, as well as on risk profiles and uncertainties, will therefore require regular review and adjustment to the plans and mitigating provisions, as necessary. This requires the replacement plan for the coal-fired generation facilities to be flexible and adaptive, because it absorbs most of the uncertainties associated with other resources.

The OPA has identified a number of factors that will affect the evolution of the coal-fired generation replacement plan in response to new information that materializes from implementing various elements of the IPSP in the time period from now to 2014/2015. These are illustrated in Figure 2.18.

Figure 2.18 – Issues and Evolving Information that Affect the Coal Replacement Plan



Source: OPA

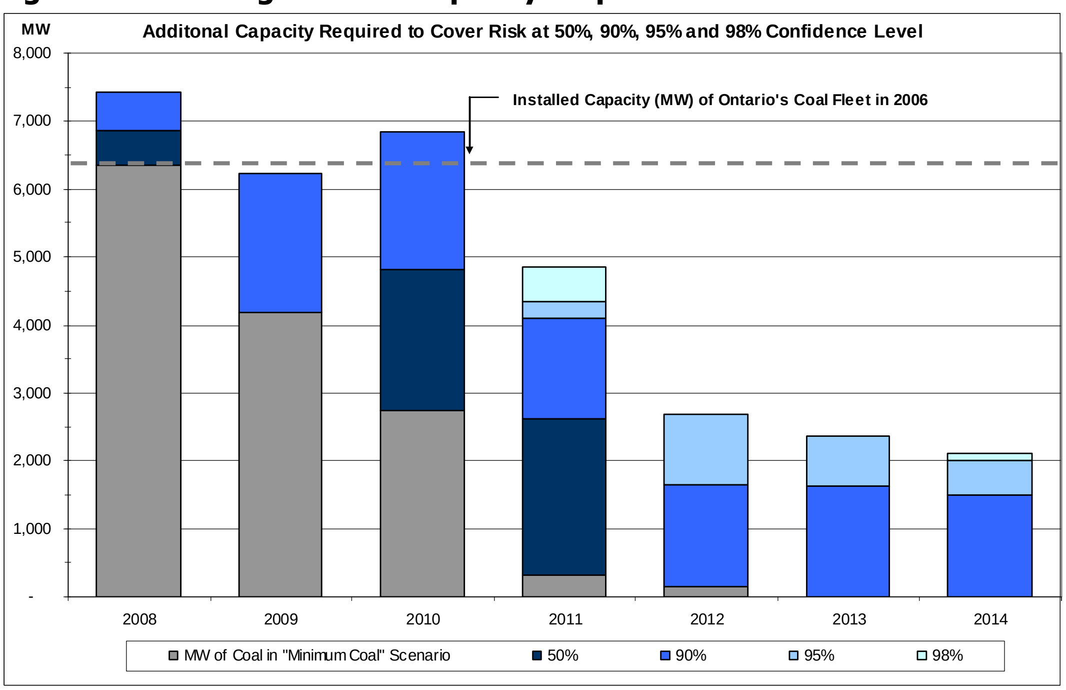
These factors relate to the status and outcome of ongoing developments on a number of issues, such as uptake and performance of new renewable resources, CDM, plans for nuclear refurbishments and transmission infrastructure. As discussed earlier, these will necessitate regular review and adjustment of the plan, without losing sight of its primary objective of replacing coal. Figure 2.18 also identifies a number of issues that will require decisions to be made in the near term relating to the operational and environmental performance of the operating coal-fired units until they are taken out of service.

An uncertainty analysis was performed to estimate the net impact of the various risk elements on capacity requirements. In the analysis, a probability distribution of system capacity impacts was calculated based on possible combinations of risk conditions and the joint probability of these combinations occurring.

Figure 2.19 shows the results of this analysis based on an assessment of risks and uncertainties as of the fall of 2006. Results are expressed in terms of the capacity requirements necessary to achieve different levels of confidence in meeting system adequacy requirements, e.g., 50 percent, 90 percent.

The Minimum Coal Requirements in Figure 2.19 represent the amounts of coal-fired generation required to meet generation adequacy requirements, assuming all planned resources (CDM, gas, renewable resources and transmission) are implemented on time. They are based on the set of assumptions in the Preliminary Plan. In 2008, measures in addition to the retention of coal-fired generation may be required, such as electricity imports. In subsequent years, risk coverage is improved and the installed coal capacity is more than adequate to provide the requisite risk coverage at high confidence levels.

Figure 2.19 – Range of Coal Capacity Requirements as Seen in 2006



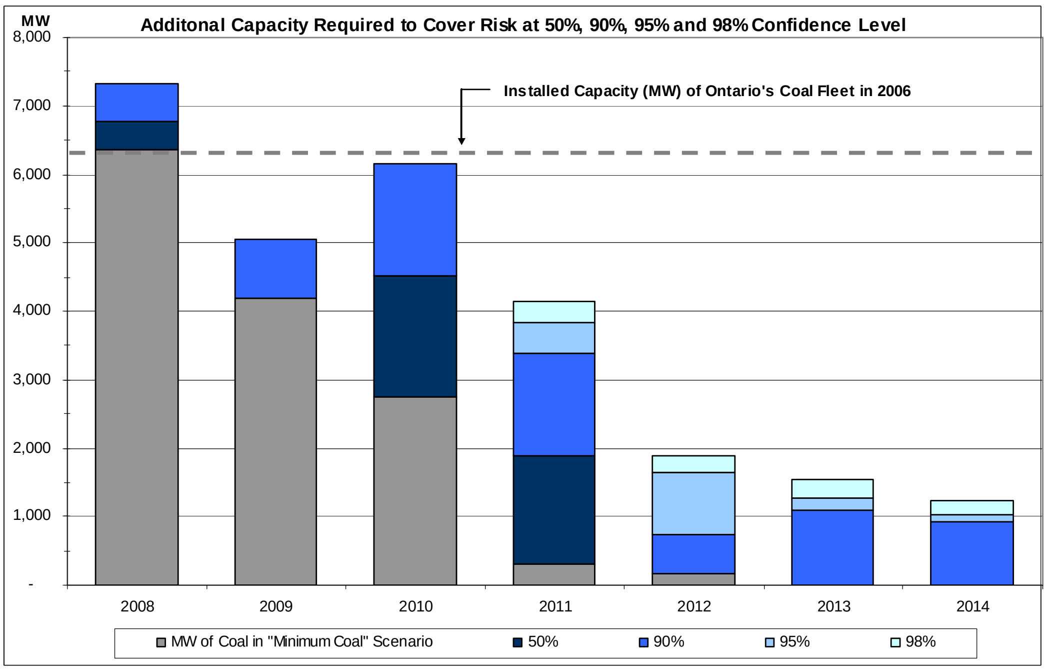
Source: OPA

Based on the risk analysis results as shown in Figure 2.19, we consider it prudent to:

- retain the existing coal-fired generation capacity in-service to at least 2010
- gradually reduce the coal-fired capacity starting in 2011 to about half of the current installed capacity, after which the coal-fired generation is removed from service by 2015.

With the passage of time, better information concerning many of the risk factors will become available, for example, the status of generating units scheduled to be placed in-service and the success in achieving CDM potential. As this information becomes available, our assessment of future risks will change, and it may be possible to reduce the amount of coal-fired generation required to cover these risks. Figure 2.20 illustrates the range of coal capacity requirements that would be assessed at the end of 2008 if all of the resources planned to be placed in-service up to and during 2008 were on time, and all other conditions remained the same. Clearly, the uncertainties are reduced if the projects planned for 2007 and 2008 are all successful.

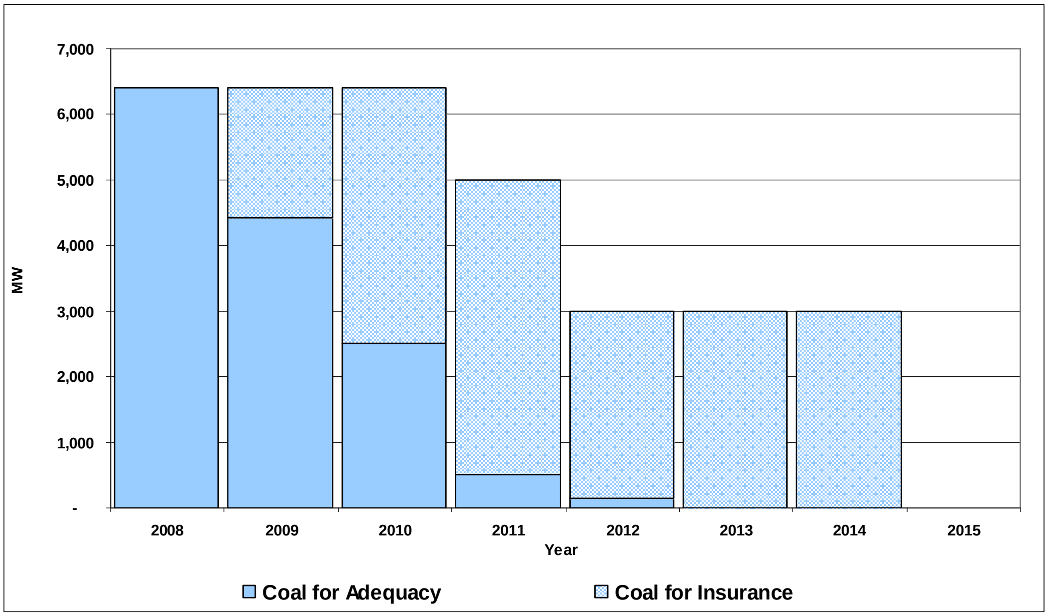
Figure 2.20 – Illustrative Range of Coal Capacity Requirements as Seen in 2008 Assuming All Goes According to Plan to 2008



Source: OPA

Based on the range of capacity requirements shown in Figure 2.19, we consider it prudent to plan on maintaining sufficient coal capacity in-service to cover the adequacy and insurance requirements shown in Figure 2.21.

Figure 2.21 – Range of Coal Capacity Requirements



Source: OPA

Explore the Potential for Emission-Reduction Technology

Figure 2.22 shows the forecast range of coal-fired energy production during the period 2008 – 2014, first assuming that only the minimum amount of coal-fired generation is producing energy, and then assuming the amount of coal-fired generation required for insurance is producing energy. With minimum coal-fired generation, energy production declines steadily, from about 30 TWh in 2008 to zero in 2012. However, if all the insurance coal is operating until the end of 2014, the forecast coal production declines from about 30 TWh in 2008 to about 15 TWh for the period 2012 through 2014. Prudent planning requires that Ontario plan on using the insurance coal until the end of 2014.

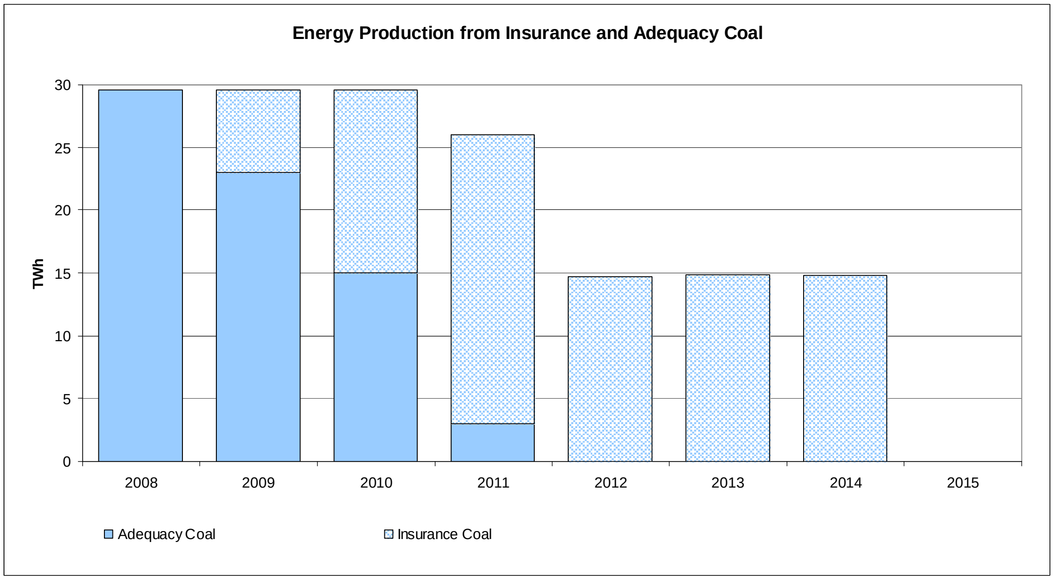
Figure 2.23 shows a range of forecast emissions in 2010 based on the production levels shown in Figure 2.22, before emission control technology improvements are considered. The lower amount represents emissions with minimum coal and the higher amount represents emissions with insurance coal. These are compared to historical emissions during the period 1985 – 2005.

Actual emissions have generally declined over the period, and this trend is continued if the minimum coal burn is achieved. However, if insurance coal continues to be required in 2010, there is a potential for increased emissions of mercury and NOx. Consideration should be given to emission control technology improvements to mitigate the environmental impacts of burning coal. In particular, the following alternatives should be considered:

- installation of Selective Catalytic Reduction facilities on Nanticoke units 5 and 6
- installation of baghouses
- installation of scrubbers on some or all of Nanticoke units 5 – 8
- maximizing the use of biomass feedstock for co-firing of boilers.

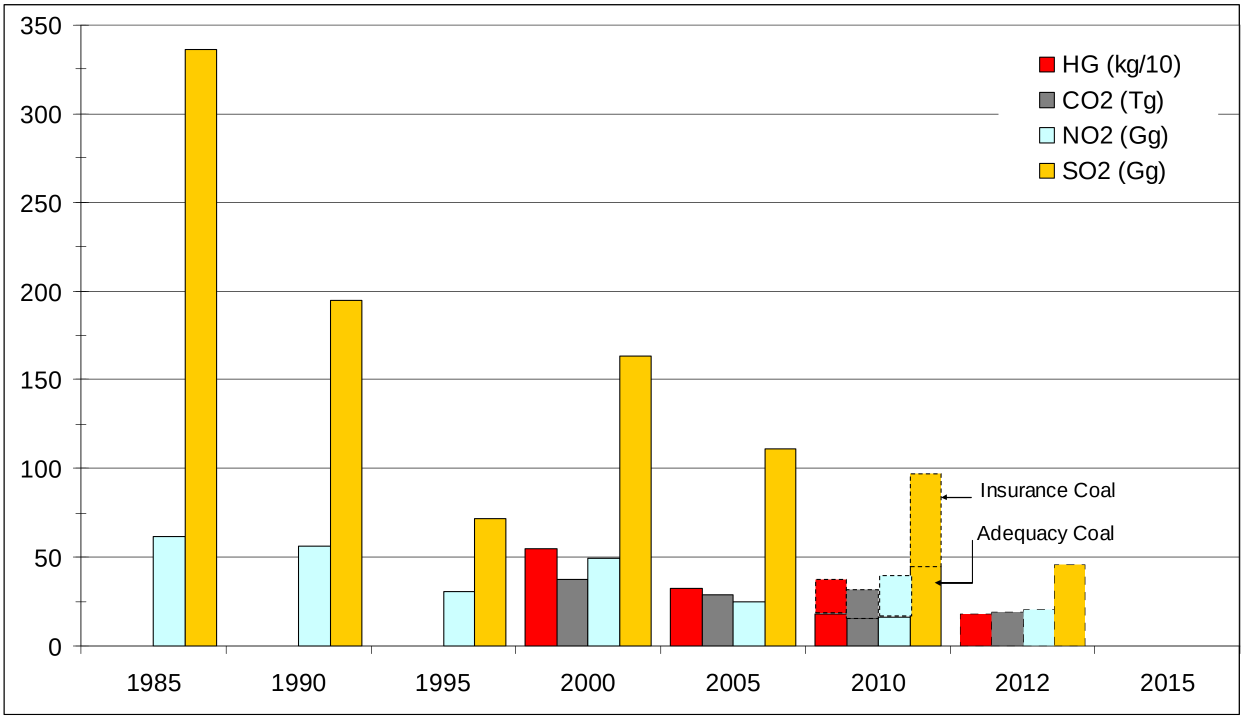
Work is in progress to assess the environmental impact of various emission control technology options. We will be providing further information on the environmental aspects in a future appendix to this report.

Figure 2.22 – Forecast Coal-Fired Energy Production



Source: OPA

Figure 2.23 – Historical and Forecast Emissions From Coal Generation



	1985	1990	1995	2000	2005	2010	2012	2015
HG (kg/10)				55	32	18 - 36	0 - 18	-
CO2 (Tg)				38	29	16 - 28	0 - 19	-
NO2 (Gg)	62	56	31	49	25	17 - 39	0 - 20	-
SO2 (Gg)	336	195	72	163	111	45 - 96	0 - 46	-

Source: OPA (Forecast), OPG (Historical).

The Proposed Coal Replacement Plan

The coal requirements shown in Figure 2.21 are required to manage system capacity risks based on the current view of risks. However, during the next few years, as additional CDM initiatives are implemented and supply resources are placed in-service, the assessment of capacity risk will change, and if resources are placed in-service as scheduled, it will be possible to reduce the amount of insurance required to manage the revised assessment of risks. This creates the opportunity to shut down coal-fired generating units earlier. The proposed coal-fired generation replacement plan comprises the following components:

1. Retain the existing coal-fired generation capacity in-service to 2010 concurrent with the ability to produce 20-25 TWh of electricity per year. This can be accelerated under certain favourable conditions.
2. Gradually reduce the coal-fired capacity starting in 2011 to about half of the current installed capacity and plan to operate this reduced capacity to the end of 2014.
3. Improve the environmental performance of the operating coal-fired generation facilities to the extent practical during the transition period to 2014, in accordance with the

recommended capacity requirements identified in Figure 2.21, and consistent with meeting applicable and evolving regulatory requirements.
4. Retain plan flexibility and adjust the plan as necessary, based on regular review of risk profiles and new and pertinent information that becomes available.
5. Consider options for potential future use of the coal-fired generation sites.

Continuous monitoring of conditions will require close cooperation and consideration with the IESO and OPG to determine the specific role of the coal-fired generation units over the next several years. This is particularly true for Atikokan GS and Thunder Bay GS, which are important not only for overall system adequacy, but also to ensure adequacy in the northwest system. Based on preliminary OPA studies, there is a potential requirement to maintain generation capacity at Atikokan in-service until replacement generation becomes available. This could include conversion of the plant to biomass operation. Additional studies will be conducted for the IPSP to confirm this requirement.

Close cooperation and coordination is also required for the shutting down of units at Nanticoke GS. As outlined in paper #5, replacement reactive power is required for voltage support before all Nanticoke units can be removed from service.

2.8 Step Eight: Transmission Integration

2.8.1 Renewable Resources and Transmission Integration

More than any other resource type, the development of renewable resources is highly affected by the availability and capability of the transmission system. Renewable potential in Ontario is large, but much of it is located in remote areas of the province that presently have no grid access, or where the existing transmission system does not have the capacity to deliver the power output from a major resource development. Thus, an integrated resource development plan that has a sizeable component of renewable resources, such as the IPSP, must have an associated transmission development plan that enables the resource development.

In the development of this integrated renewable resources/transmission plan, there are a number of key considerations:

- amount of renewable resources in the plan – this is provided by the resource plan (step 5 of this paper)
- location of the renewable resource potential – this is based on the information provided by the various referenced studies carried out for the IPSP, as summarized in the supply resources paper (#4), plus assessment of feasibility
- transmission capabilities and reinforcement options – this is discussed in detail in the transmission discussion paper (#5)
- lead time requirements – information specific to the renewable or transmission development element

- cost consideration – development priorities in consideration of the resource, connection and bulk transmission costs and losses.

Transmission developments tend to involve major capital expenditure with a corresponding major increase in capacity. For this reason, it is generally not possible to exactly match the development of transmission to the slower incremental development of resources or load. Typically, large transmission capacity is added with the initial resource development. The unused capacity would then be utilized if and when additional resources are developed over time.

In the case of renewable resources for Ontario, there is a logical order for renewable development that optimizes transmission use and future expansion. Resources have been prioritized first according to cost effectiveness and then according to transmission capabilities and feasibility of each development. The basic cost comparison for each development was introduced in the supply resources discussion paper (#4). The comparison includes energy costs, costs from losses, connection costs and bulk transmission system upgrades.

In general, bulk transmission system upgrades are triggered by large, low-cost hydroelectric developments, not by smaller, higher-cost wind and bioenergy sites. After an upgrade is triggered by a large development, there may still be capacity available for further development of wind, hydro or bioenergy, in which case these developments could proceed without causing additional upgrade cost. Conversely, there are some areas which contain enough smaller resource sites to collectively trigger a bulk system upgrade. In these cases, the cost of the upgrade is allocated for costing purpose among each of the sites that will be using the upgrade. Major system upgrade costs have been itemized and estimated in section 3.5, "Implementing the Plan".

Staging of renewable development is also heavily affected by transmission system limits and timelines for implementing transmission upgrades. Renewable resources development in several areas has been delayed in order to allow for incoming upgrades to the system, despite the presence of cost-effective resources. These areas include Bruce Peninsula, Lake Huron shore near Goderich, and Parry Sound in southern Ontario and major developments in the Sault Ste. Marie and Manitoulin areas in northern Ontario.

This section presents five stages with increasing amounts of renewable resources that could be integrated by deploying different degrees of transmission reinforcement. These stages provide for additional new renewable development totalling 2,000 MW (Stage 1), 3,700 MW (Stage 2), 4,900 MW (Stage 3), 6,400 MW (Stage 4) and 10,000 MW (Stage 5). A discussion of each stage is presented below.

Stage 1: Renewable Resources Transmission Integration

Stage 1 accommodates the development of new renewable resources from 2012 to 2014 in the Preliminary Plan. The renewable resources proposed to be developed total 2,000 MW, of which approximately half is in southern Ontario and half in northern Ontario, as follows:

- 700 MW of wind (southwestern and eastern Ontario) and 200 MW of bioenergy in southern Ontario
- 150 MW of wind (Algoma/Manitoulin area), 500 MW of hydro (the Mattagami Extension, re-development of Smoky Falls and other northeast hydro) and 50 MW of biomass in the northeast
- 150 MW of hydro (Little Jackfish and others), 50 MW of wind and 200 MW of biomass (Atikokan) in the northwest.

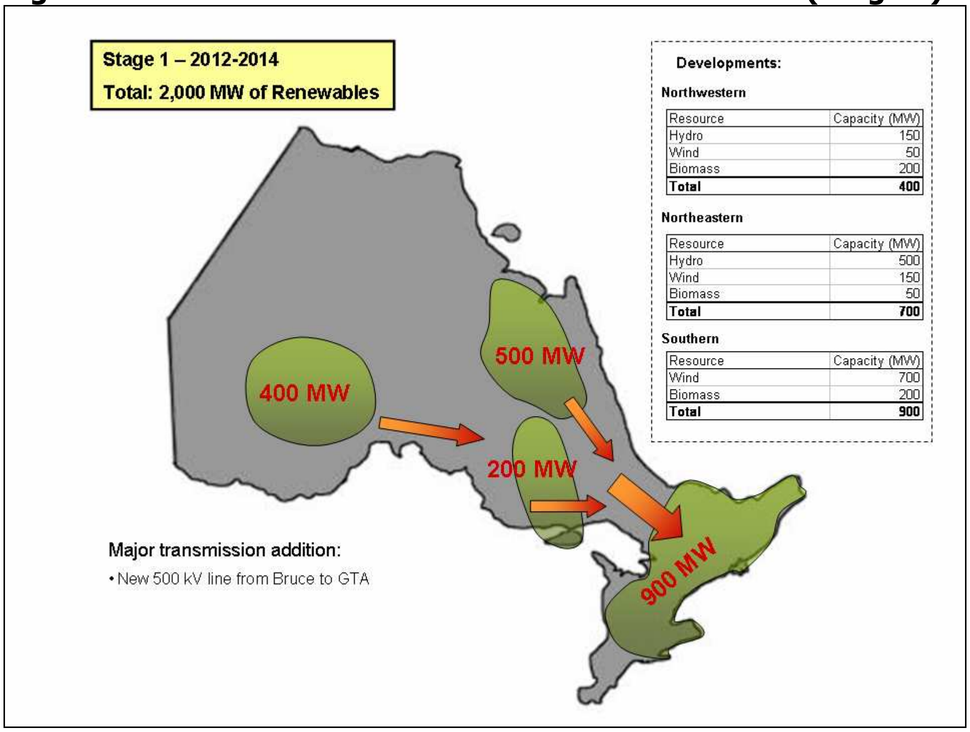
The key transmission assumptions made for this stage are:

- the construction of a new 500 kV transmission line from the Bruce Peninsula to the GTA with sufficient capability to allow further wind power development in the Bruce area
- the reinforcement of the existing North-South Tie by the addition of series compensation
- additions of reactive power compensation in the Algoma, Timmins and Kirkland areas
- the construction of "enabler" connection lines from the Little Jackfish hydro development to the Nipigon area, and the wind resources along the Lake Huron shore near Goderich to the Bruce transmission system.

This stage minimizes the need for new transmission for the development of a number of economic renewable resource groups by maximizing the utilization of the existing east-west and north-south inter-regional transmission paths.

Figure 2.24 summarizes the renewable and transmission developments proposed for this stage.

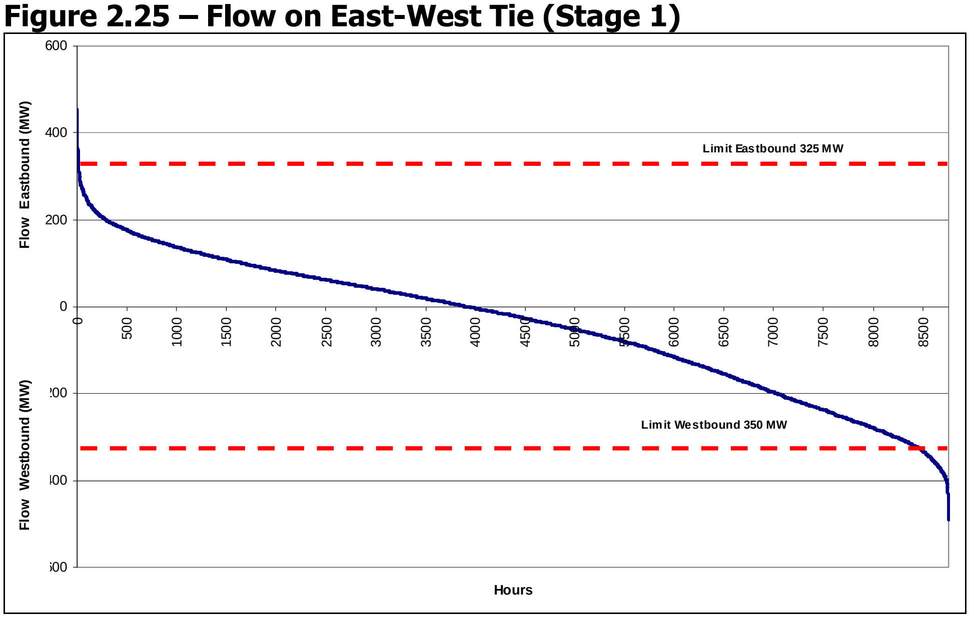
Figure 2.24 – Renewable Resources and Transmission (Stage 1)



Source: OPA

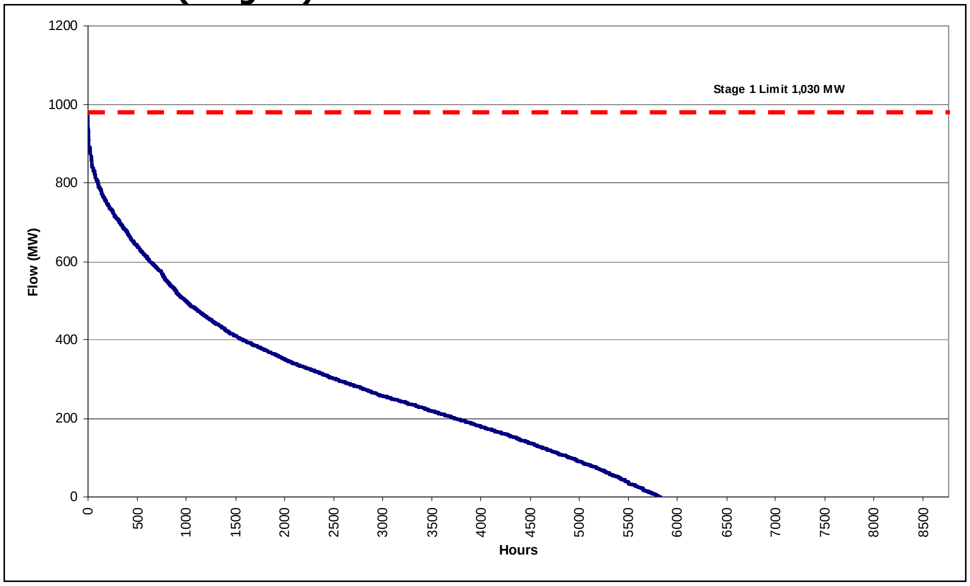
The loading on a number of critical transmission paths north of the GTA for this stage, assuming 2014 conditions, is shown in Figure 2.25, Figure 2.26, Figure 2.27, and Figure 2.28.

Figure 2.25 – Flow on East-West Tie (Stage 1)



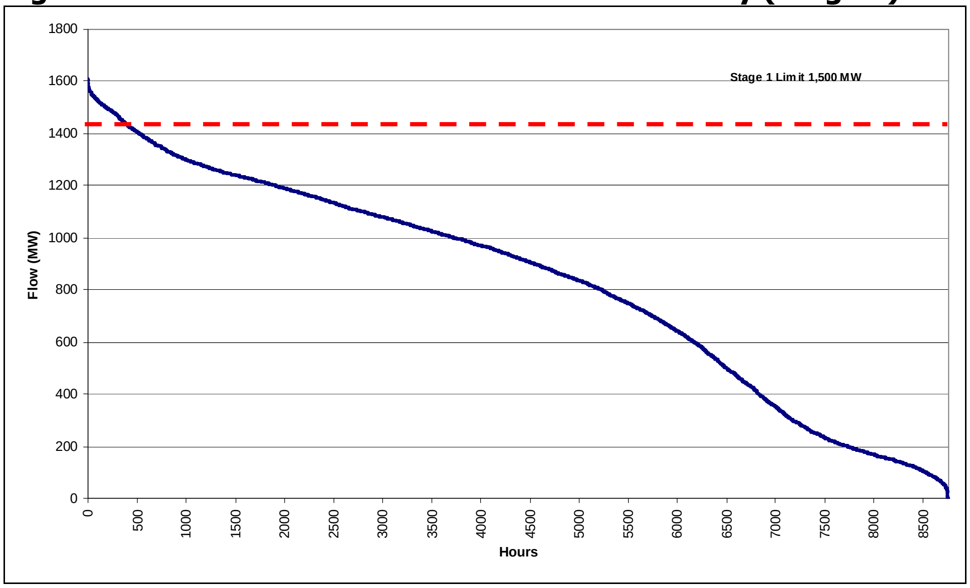
Source: OPA

Figure 2.26 – Flow East from Mississagi/Algoma to Sudbury (Stage 1)



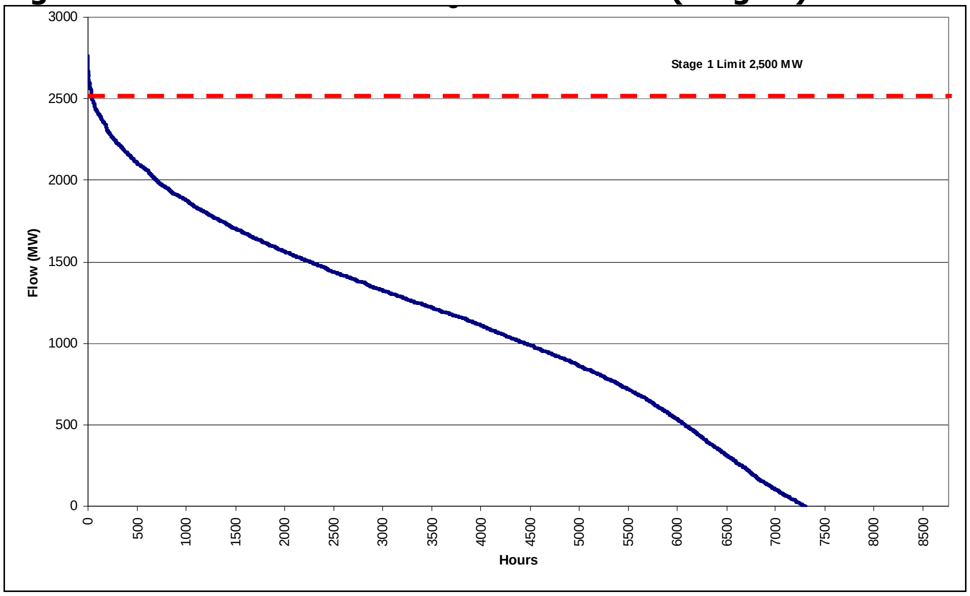
Source: OPA

Figure 2.27 – Flow South from Timmins to Sudbury (Stage 1)



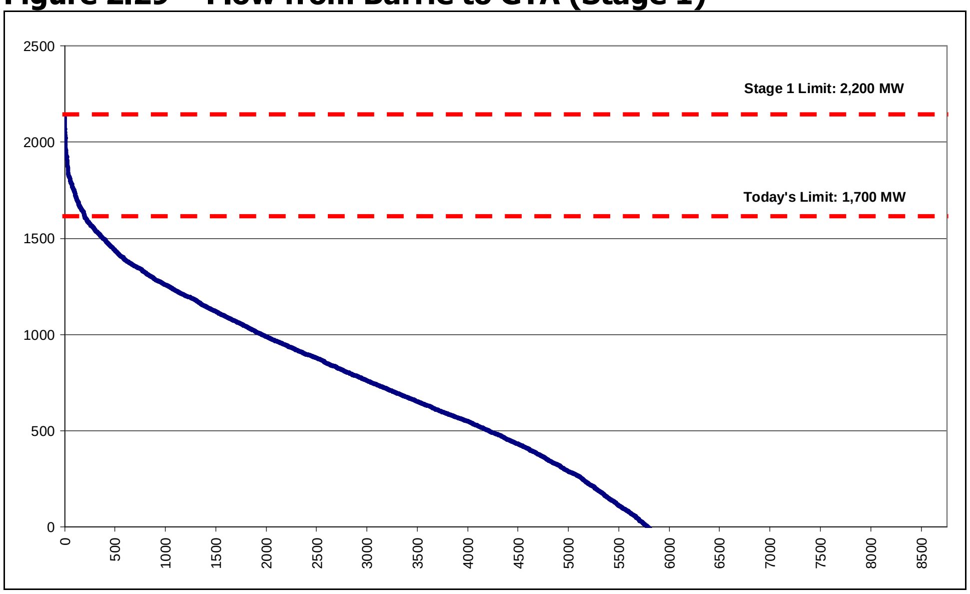
Source: OPA

Figure 2.28 – Flow South on North-South Tie (Stage 1)



Source: OPA

Figure 2.29 – Flow from Barrie to GTA (Stage 1)



Source: OPA

It is seen that the Stage 1 transmission reinforcement accommodates the associated new renewable resources for these four paths.

Stage 2: Renewable Resources Transmission Integration

This stage depicts the development of new renewable resources included from 2015 to 2017 in the Preliminary Plan. The renewable resources proposed to be developed total 3,700 MW – a

1,700 MW increase from Stage 1. The incremental renewable development for this stage is as follows:

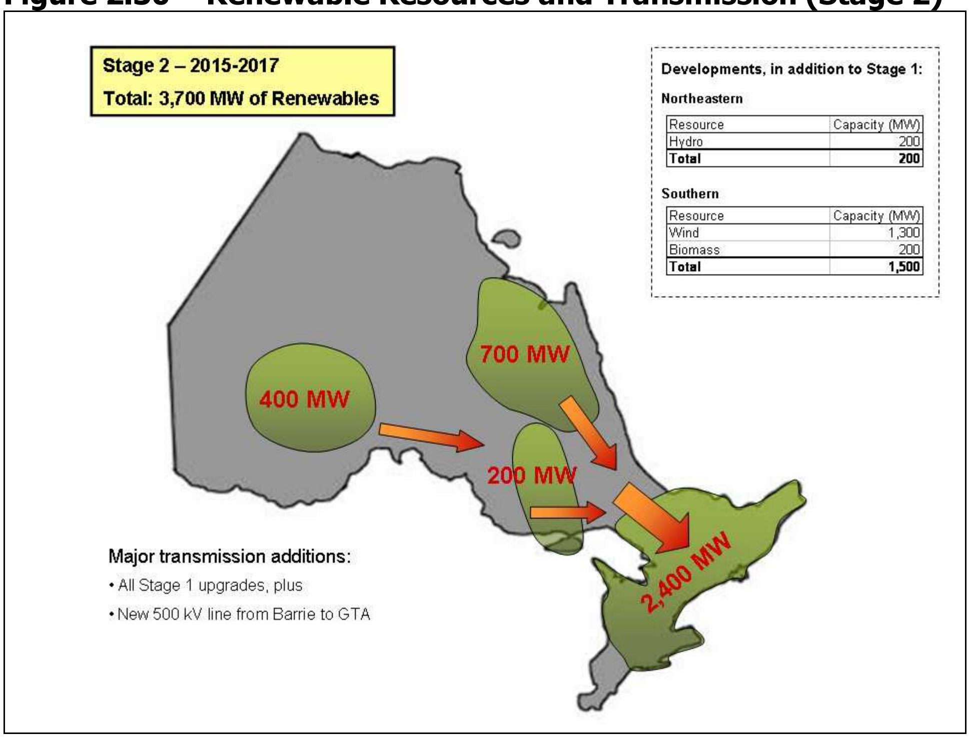
- 200 MW of hydroelectric development in northeastern Ontario
- 1,300 MW of wind in southern Ontario (Bruce, Parry Sound and southwestern Ontario); for this discussion, Parry Sound wind resources are included in southern Ontario because it is assumed to be connected to the Essa station
- 200 MW of bioenergy in southern Ontario.

The key transmission assumptions made for this stage are:

- the construction of a new 500 kV transmission line from the Barrie area to the GTA
- the construction of “enabler” connection lines from wind resources located along the north-eastern shore of Georgian Bay to Parry Sound and along the Bruce Peninsula to Owen Sound.

Figure 2.30 summarizes the renewable and transmission development proposed for this stage.

Figure 2.30 – Renewable Resources and Transmission (Stage 2)



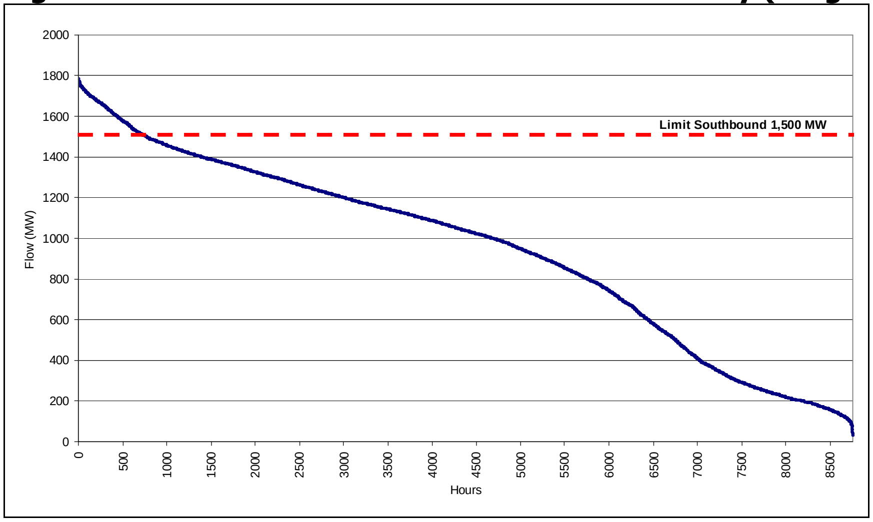
Source: OPA

By the end of this stage, most of the cost-effective renewable potential in southern Ontario would have been harvested. The main uncertainty here is associated with the extent to which the conceptual potential can be realized, in consideration of siting issues, community acceptance, land availability and project economics. Greater availability of renewable resources in southern Ontario would defer the next development stage, lesser availability would advance that stage.

Figure 2.31, Figure 2.32 and Figure 2.33 show the impact of the new northeast hydroelectric generation on the flow first to Sudbury, then the North-South Tie (Sudbury to Barrie), and then from Barrie to the GTA in 2017.

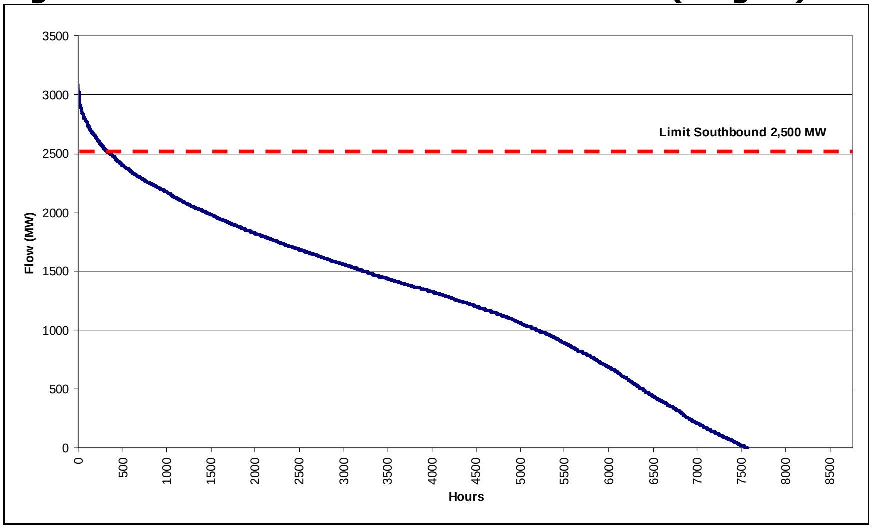
Stage 2 transmission reinforcement is seen to be adequate.

Figure 2.31 – Flow South from Timmins to Sudbury (Stage 2)



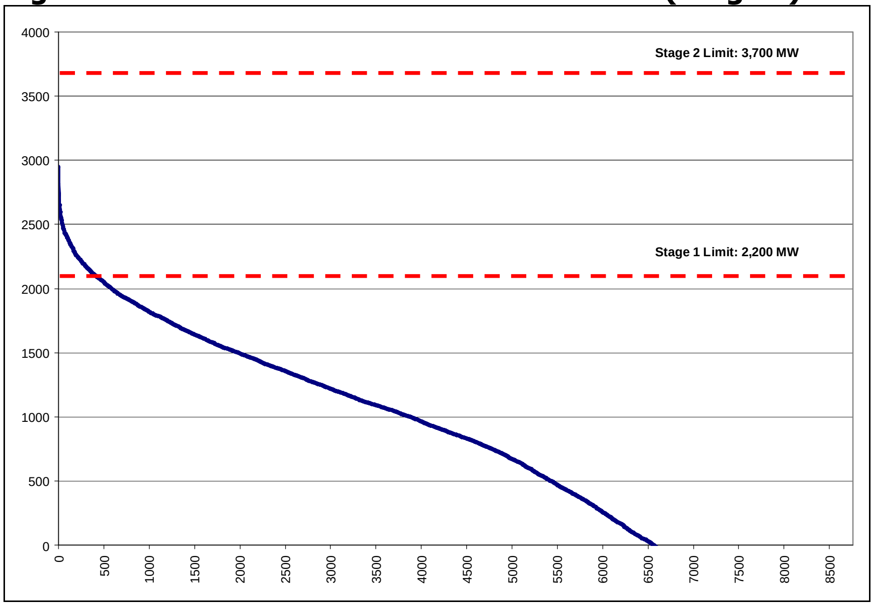
Source: OPA

Figure 2.32 – Flow South on North-South Tie (Stage 2)



Source: OPA

Figure 2.33 – Flow South from Barrie to GTA (Stage 2)



Source: OPA

Stage 3: Renewable Resources Transmission Integration

This stage depicts the development of new renewable resources included from 2018 to 2019 in the Preliminary Plan. The renewable resources proposed to be developed total 4,900 MW – a 1,200 MW increase from Stage 2. In this stage, economic renewable resources are assumed to be fully developed in southern Ontario, and additional renewable resources are obtained from developments in northeastern Ontario. Until major hydroelectric generation north of Timmins can be developed, by around 2020, the new northeast renewable resources will be derived from wind resources in the Sault/Algoma/Manitoulin area that comprise 1,000 MW of wind generation and 500 MW of pumped generation storage.

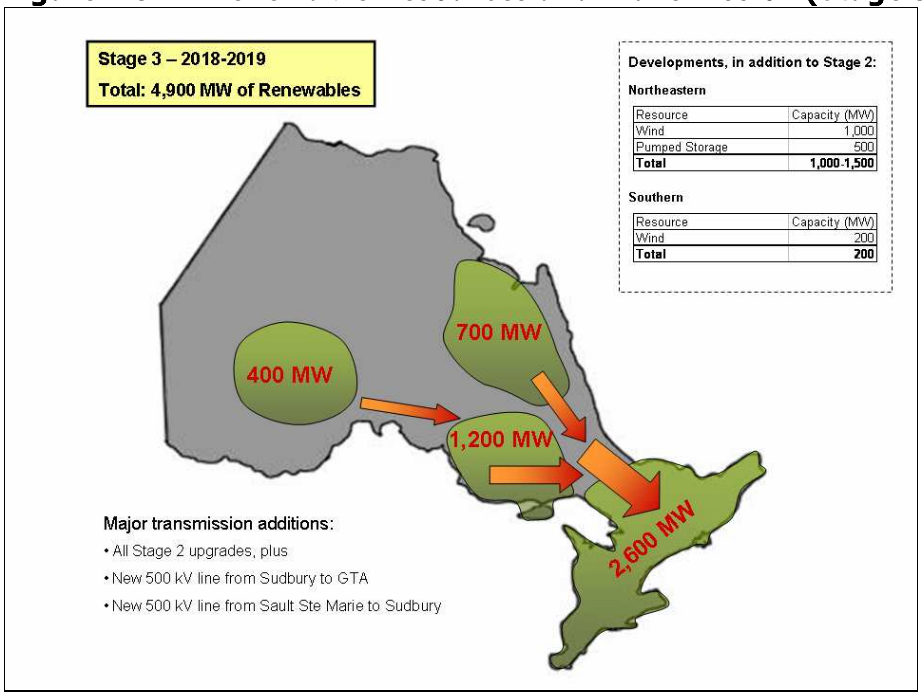
This development, as well as subsequent developments in northern Ontario, necessitates the reinforcement of the critical north-south path between Sudbury and the GTA. For the Sault Ste. Marie area development, the Sault/Algoma to Sudbury transmission path needs to be reinforced. Thus, the key transmission assumptions made for this stage are:

- construction of a new 500 kV transmission line from Sudbury to the GTA
- construction of the second 500 kV line from the Mississagi station in the Algoma area to the Hanmer station in the Sudbury area, and the conversion of the existing line to 500 kV operation
- construction of “enabler” connection lines to connect the wind resources in the Manitoulin area and north of Sault Ste. Marie.

This stage signifies the first step in the development of significant renewable potential in northern Ontario. The critical element in facilitating this is the expansion of the north-south transmission system between Sudbury and the GTA.

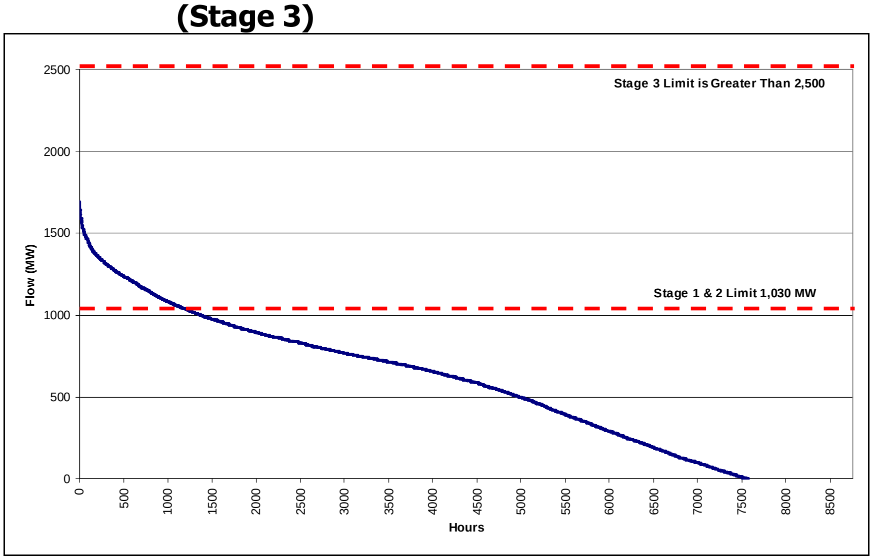
Figure 2.34 summarizes the renewable and transmission developments proposed for this stage. The loading on a number of critical transmission paths north of the GTA for this stage, assuming 2019 conditions, are shown in Figure 2.35 and Figure 2.36.

Figure 2.34 – Renewable Resources and Transmission (Stage 3)



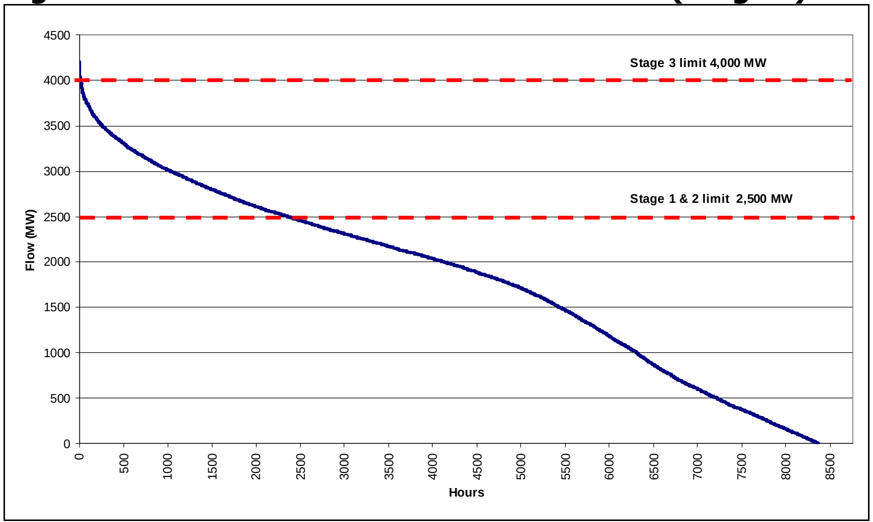
Source: OPA

Figure 2.35 – Flow East from Mississagi/Algoma to Sudbury (Stage 3)



Source: OPA

Figure 2.36 – Flow South on North-South Tie (Stage 3)



Source: OPA

The figures show Stage 3 transmission reinforcement to be both needed and adequate to accommodate the increased supply resources.[13]

Stage 4: Renewable Resources Transmission Integration

This stage depicts the development of new renewable resources included from 2020 to 2022 in the Preliminary Plan. The renewable resources proposed to be developed total 6,400 MW – a 1,500 MW increase from Stage 3. This stage assumes the development of the 1,000 MW of hydroelectric generation potential in the Moose River Basin, 500 MW of additional wind resources in the Sault/Algoma area and an addition of 500 MW of pumped storage capacity in the Sault/Algoma area.

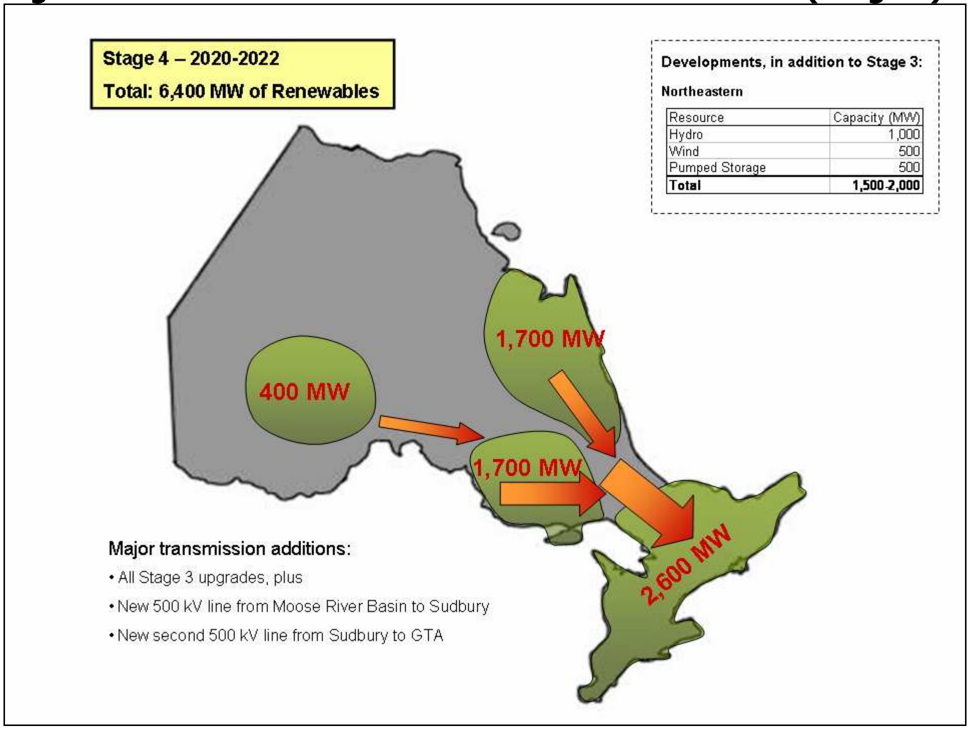
These developments necessitate further reinforcement of the critical north-south path between Sudbury and the GTA. The Moose River Basin development requires a new transmission line between Sudbury and the Moose Basin. Thus, the key transmission assumptions made for this stage are:

- construction of the second 500 kV transmission line from Sudbury to the GTA
- construction of a new 500 kV line from Sudbury to the Moose River Basin
- construction of additional connection lines in the Sault/Algoma area to connect the pumped storage plant in the Sault area to the northeast transmission system.

Figure 2.37 summarizes the renewable and transmission developments proposed for this stage. The loading on a number of critical transmission paths north of the GTA for this stage, assuming 2019, conditions are shown in Figure 2.38, Figure 2.39 and Figure 2.40. The figures show Stage 4 transmission reinforcement to be both needed and adequate to accommodate the increased supply resources.

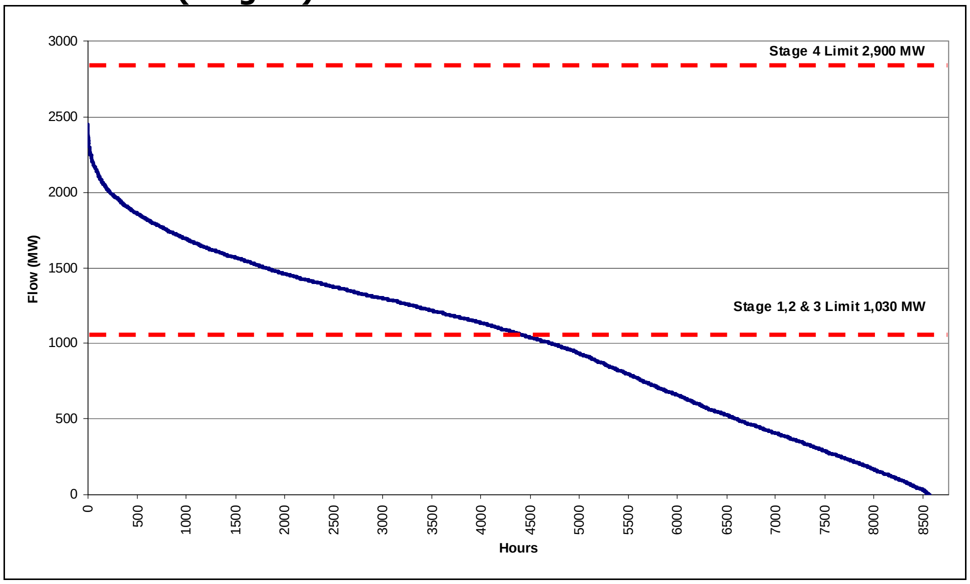
[13] That is, without the Stage 3 reinforcement, there would be congestion in the flow south about 2,500 hours per year, and with the reinforcement there is no congestion.

Figure 2.37 – Renewable Resources and Transmission (Stage 4)



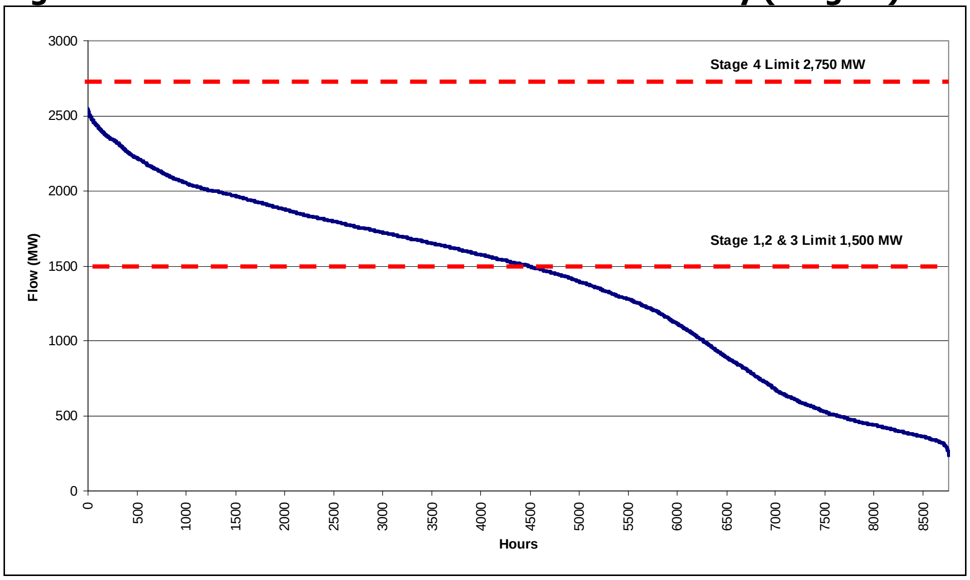
Source: OPA

Figure 2.38 – Flow East from Mississagi/Algoma to Sudbury (Stage 4)



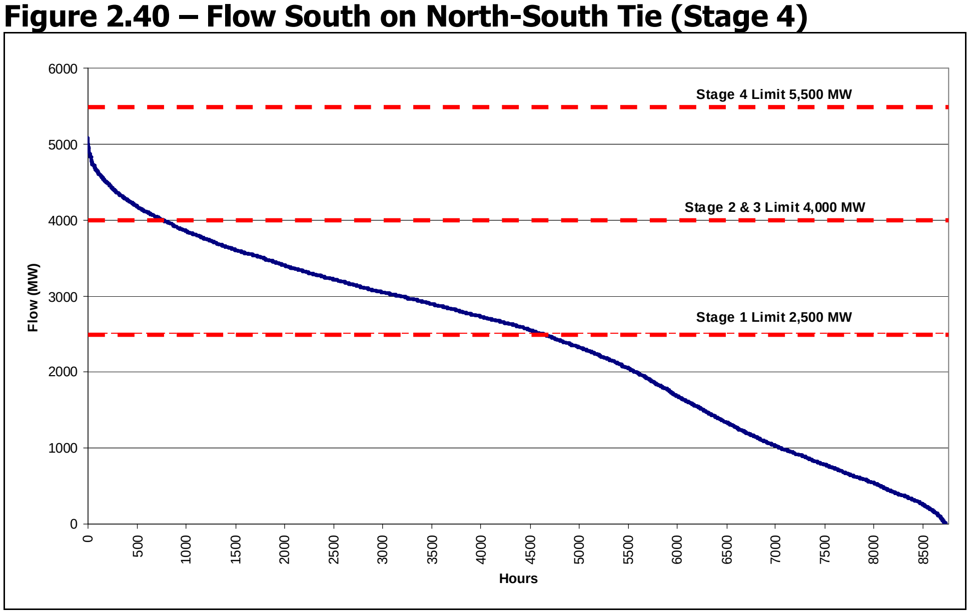
Source: OPA

Figure 2.39 – Flow South from Timmins to Sudbury (Stage 4)



Source: OPA

Figure 2.40 – Flow South on North-South Tie (Stage 4)



Source: OPA

Stage 5: Renewable Resources Transmission Integration

This stage conceptualizes the development of renewable resources beyond 2022, to a level of 10,000 MW – a 3,600 MW increase from Stage 4. This level is beyond the renewable target in the ministerial directive to the OPA, and beyond the level of resources in the Preliminary Plan. The renewable development assumed in this stage is 1,900 MW of combined hydroelectric and wind generation potential along the Albany River, and 1,700 MW of combined purchases from Manitoba and renewable developments in the northwest.

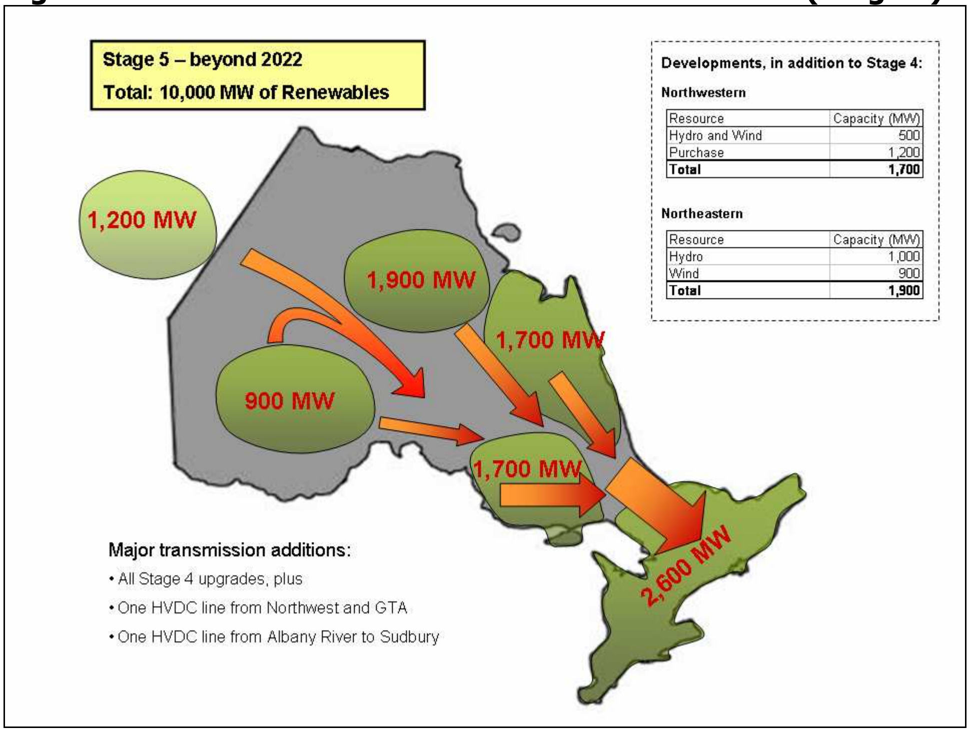
These developments necessitate further reinforcement of the transmission system north of Sudbury, with the reinforcement possibly extending south from Sudbury to the GTA. There would also need to be reinforcement from the Manitoba supply point to the GTA. The key transmission assumptions made for this stage are:

- The construction of a direct current 500 kV line from the Albany development to Sudbury, with converter equipment at the two terminals. The assumption being made here is that the reinforcements made on the north-south transmission system in Stages 3 and 4 are sufficient for transmitting the power from the Albany development south from Sudbury to the GTA on the reinforced north-south tie. Further technical studies would be required to verify this. Should the north-south capability be insufficient to do this, the new DC line from Albany would continue to the GTA, with converter equipment located in the GTA instead of Sudbury.
- The construction of a direct current 500 kV line from the Manitoba supply point (assumed to be the Conawapa development) to the GTA via Thunder Bay and Sudbury, with converter equipment at the two end terminals and near Thunder Bay. The latter is to provide a connection to the northwest to enable the development of up to 500 MW of renewable resources in the area.
- The construction of "enabler" lines to connect wind generation in the Albany area to the Albany converter station, and wind generation in the Thunder Bay area to the converter station in the Thunder Bay area.

Figure 2.41 summarizes the renewable and transmission development proposed for this stage.

The above discussion details the conceptual development of renewable resources in the Preliminary Plan and the associated transmission development required, much of it affecting northern Ontario. The basic theme of this integration exercise is to stage the renewable developments to fully utilize the capability of the existing transmission system and harvest the lower cost renewable potentials in southern Ontario. When the available renewable resources in southern Ontario are fully developed, the significant renewable potentials in northern Ontario would be tapped. The challenge is to reinforce the major transmission paths in a timely fashion to enable the development of these renewable resources in northern Ontario and in the Bruce area. The basic conclusion is that the significant renewable potential could not be realized without the requisite transmission improvements.

Figure 2.41 – Renewable Resources and Transmission (Stage 5)



Source: OPA

2.8.2 Conventional Generation and Transmission Development Integration

This section draws on the preceding discussion of the transmission subsystems related to integrating conventional generation resources, namely Bruce/southwestern Ontario to the GTA, eastern Ontario to the GTA and the bulk transmission system within the GTA. This region is shown in Figure 2.42.

Preliminary conclusions on suitable new generation are provided from a transmission integration perspective. The conclusions simply identify conventional generation that could be integrated relatively straightforwardly to yield a robust system and minimize transmission investment. Decisions on new conventional generation will be based on a number of factors in addition to transmission integration. Therefore, whatever decision is made on conventional generation, there will be a transmission integration requirement.

This analysis used the following general requirements / guiding principles with regard to the development of conventional resources in Ontario:

- conventional resources, such as nuclear or natural gas-fired generating plants, are typically large developments that are possible only at a limited number of sites
- the transmission system for incorporating baseload plants must have adequate delivery capacity available to these plants at all times

- system security is an important consideration for incorporating these resources, especially major resources that meet an appreciable portion of total demand. Where possible, there should be alternative paths for delivering power to customers from such resources
- conventional resources would be developed only in southern Ontario, locating them close to major load centres and thereby minimizing the need for transmission reinforcement.

With these requirements in mind, a scenario for developing conventional resources to best utilize the existing transmission system and minimize expansion follows below.

Figure 2.42 – Conventional Generation and Transmission

GEC: Greenfield Energy Centre; SEC: St. Clair Energy Centre; SRCG: Sarnia Regional Cogeneration Plant
Source: OPA

Bruce/Southwestern Ontario

The main considerations for developing conventional resources in this region of Ontario are related to generation incorporation at Bruce, Sarnia and Nanticoke.

Eight large nuclear units will be operating by 2012 at the Bruce complex operated by Bruce Power. This, plus 725 MW of committed wind generation in the Bruce area, will increase the committed generation resources in the area to about 7,300 MW. There is another 1,000 MW of wind resources identified for the area. If this potential is realized, the generation in the Bruce area would add up to over 8,300 MW, or nearly one fourth of Ontario's generating resources in this region of Ontario. Presently, there are two 500 kV lines and three 230 kV lines emanating from Bruce complex. This transmission system is adequate for today's need. With the committed nuclear, and committed and potential wind generation for the area, another double-circuit 500 kV line (the third) is required between the Bruce site and the GTA by 2012. Any further major generation additions in the area, such as new nuclear units developed on the Bruce site, would trigger the addition of another 500 kV line from the Bruce complex to the GTA (the fourth).

Following, the coming into service of the CES St. Clair and CES Greenfield plants in the Sarnia area, the area west of London will have a large amount of natural gas-fired generation. This area is also the connection point for power imports from the State of Michigan. The transmission system in this area will be well utilized, up to its capability, even with the shutdown of the coal-fired generating units at the Lambton plant. Any further addition of major resources west of London would trigger the expansion of this system, possibly a new 500 kV line from the London area to the Sarnia area. Since gas-fired generation can be located with some flexibility, the preference would be to site future natural gas-fired generation elsewhere in Ontario, such as the GTA or the Kitchener/Waterloo area, and not in the area west of London. This is consistent with the high value gas use strategy.

The Nanticoke site is well connected to both the GTA and the London area. After the replacement of the coal-fired units at this station, this site would have strategic value as a location for developing future major generation. With the need to maintain the Nanticoke units until the coal phase-out is complete, however, the redevelopment of this site would take place in the longer term.

Thus, in summary, from the perspective of transmission integration for the Bruce/southwestern Ontario subsystem, a new 500 kV line (the third) from the Bruce complex to the GTA is urgently needed for the committed and potential generation in the Bruce area. Another 500 kV line (the fourth) would be required if further major generation is added to the area. Generation development west of London needs to be balanced with the load in that area in order to avoid triggering a major transmission expansion between London and Sarnia.

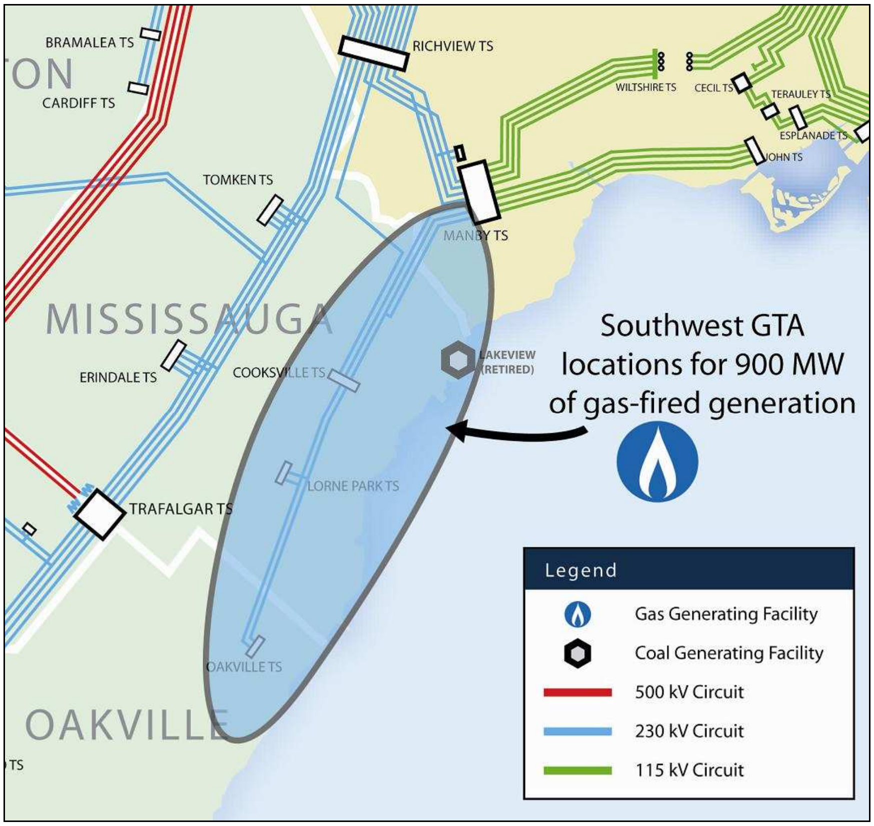
The GTA

This section discusses the main considerations for integrating conventional resources and transmission in the GTA.

Any major conventional generation development in the GTA will be gas-fired. Adoption of this strategy should be to maximize the benefits of this generation source. Generation in the GTA can provide a number of benefits, including, increasing local supply capacity and diversity, providing system and area voltage support, improving operational flexibility and relieving overloaded transmission facilities.

In section 2.6, the discussion on gas-fired generation identified a requirement for another 1,650 MW of gas-fired generation by 2011. A high value location for some of this generation can be found in the southwest part of the GTA, as shown in Figure 2.43. The transmission system in this area can accommodate approximately 900 MW of additional generation. Siting additional generation in this area is ideal because it is close to major load centres in west Toronto, Mississauga and Oakville.

Figure 2.43 – Southwest GTA Location for 900 MW of Gas-Fired Generation



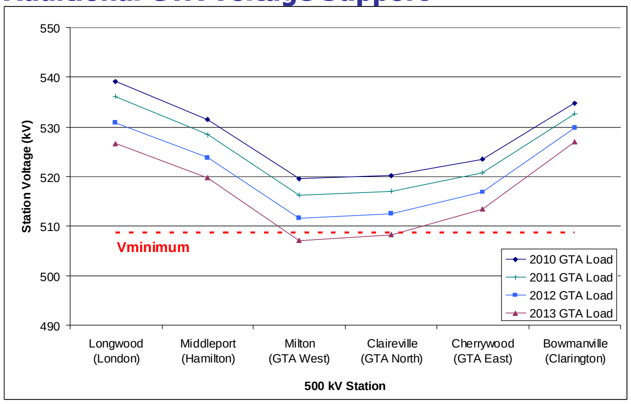
Source: OPA, IESO

This generation addresses not only the primary need of satisfying the provincial resource requirements, but also provides several other benefits for the GTA. As discussed in the transmission discussion paper, there are a number of supply issues in the GTA in the 2013 to 2015 timeframe. By 2013, the 500/230 kV Claireville transformers will be at capacity. Also by 2013, additional reactive power sources will be required to provide adequate voltage support to the overall GTA transmission system. By 2015, the Trafalgar to Richview circuits will reach capacity. By 2015, the GTA load growth would effectively equal the capacity from the new GTA generation projects (Goreway, Portlands, GTA West) currently under development. The internal generation issues we are now facing would, therefore, return without new supply sources. New generation in southwestern GTA would help to address all these issues. The benefits of southwestern GTA generation are summarized in Figure 2.44.

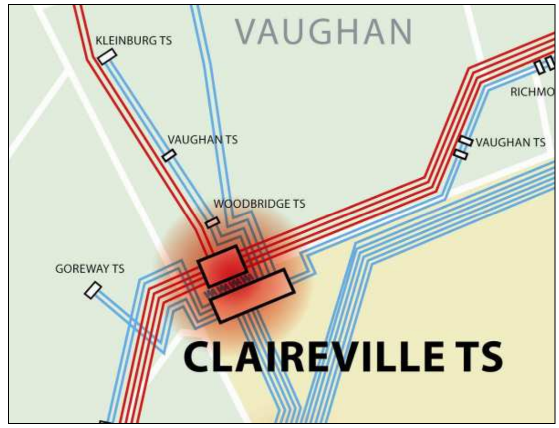
Figure 2.44 – Southwestern GTA Generation – Additional Benefits

Required by 2013:

Additional GTA Voltage Support

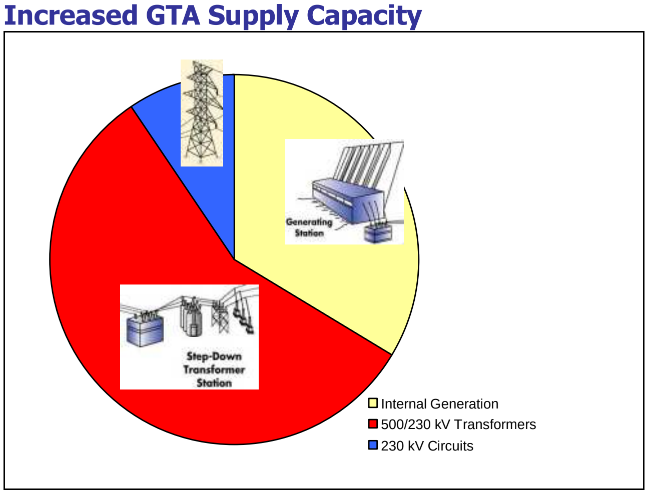


Claireville Transformer Relief



Required by 2015:

Increased GTA Supply Capacity



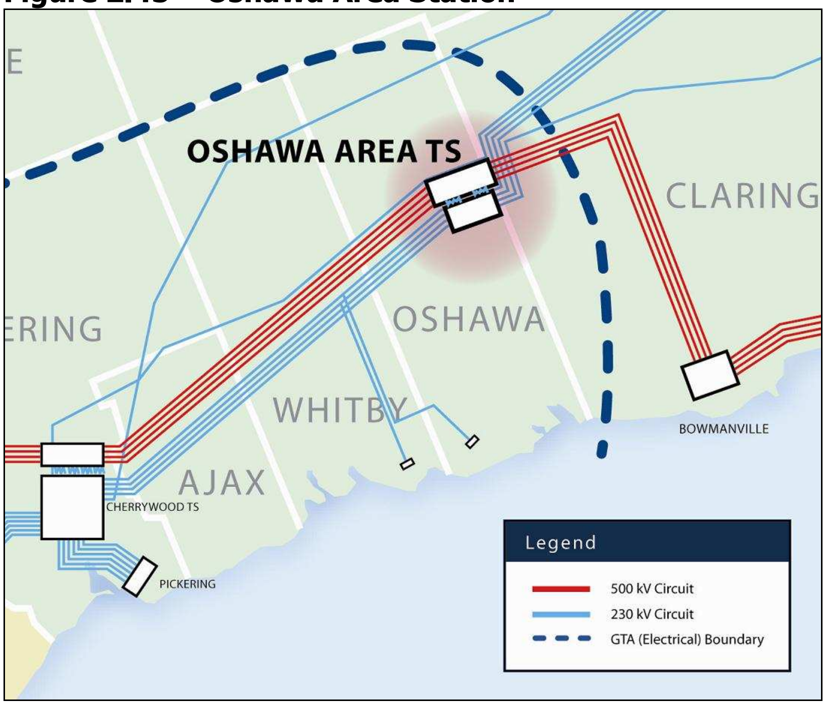
Richview to Trafalgar Corridor Relief

Source: OPA, IESO

The plans for Pickering B refurbishment or retirement will affect transmission development in the eastern GTA. At present, up to three generating units may be unavailable to cover for extended outages during the 2014 to 2018 period. The Pickering generators are connected to the 230 kV system at the Cherrywood station in the eastern part of the GTA. This reduces power transfer and loading on the large 500/230 kV Cherrywood transformers. In addition, the Pickering generators provide very critical voltage support to the GTA. With two to three generating units unavailable, additional 500/230 kV transformers and voltage support would be required. This would advance the need to develop a new transformer station at the Oshawa Area site. The development of an Oshawa Area station is part of the transmission reinforcements required to incorporate 1,400 MW of new generation at the Darlington site by

2019. The Oshawa Area station, shown in Figure 2.45, will need to consist of two 500/230 kV transformers and a 230 kV switchyard to connect the five 230 kV circuits from the Cherrywood station that supplies the Ajax, Pickering, Whitby and Oshawa areas. The need date for the Oshawa Area station will depend on developments for Darlington expansion and Pickering refurbishment.

Figure 2.45 – Oshawa Area Station



Source: OPA, IESO

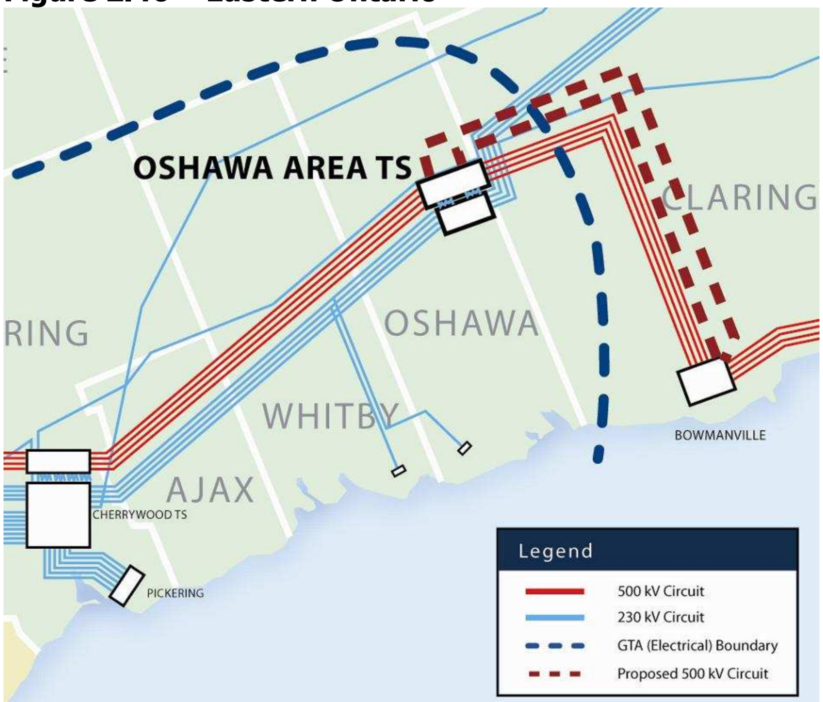
In summary, the development of conventional resources in the GTA from the transmission development and system security perspective is limited to a high-value use of gas generation in constrained areas in this region of Ontario, and the possible refurbishment of the Pickering nuclear plant.

Eastern Ontario

The main consideration in Eastern Ontario is the potential addition of 1,400 MW of nuclear generation at the Darlington site. In addition to generation at Darlington, there is a need to allow for the incorporation of additional imports from Quebec. The existing transmission corridor between Bowmanville and Cherrywood has insufficient capacity to incorporate both of these developments. The transmission facilities required for these projects include the new Oshawa Area station described above and a new 20 km double-circuit 500 kV line from the Bowmanville station to the Oshawa Area station. This is shown in Figure 2.45. The loads in the GTA East would then be supplied from the Oshawa Area station rather than the Cherrywood station. This connection to the Oshawa Area station would reduce the flows on the existing 500 kV lines to Cherrywood by more than 1,000 MW.

The transmission facilities included in the Preliminary Plan are summarized in section 4.

Figure 2.46 – Eastern Ontario



Source: OPA, IESO

3. The Preliminary Plan

This section evaluates the Preliminary Plan from the perspectives of reliability and feasibility, cost, environmental performance, flexibility and societal acceptance.

3.1 Preliminary Plan - Feasibility and Reliability Perspective

This section reviews how the plan meets capacity, energy and transmission requirements throughout the planning period and thereby meets the reliability criteria. The lead times, the options available and the way the elements are integrated meet the feasibility requirements, as outlined in the sustainability paper (#6).

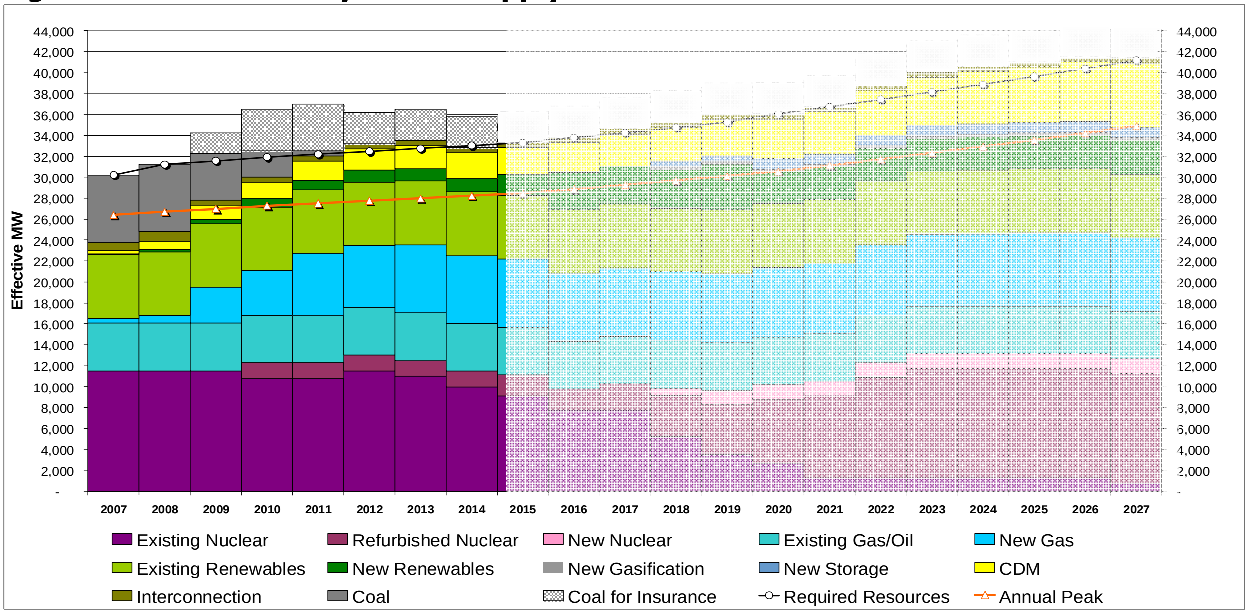
3.1.1 Capacity

The period to the end of 2014-2015 sees the replacement of Ontario's coal-fired fleet, a doubling in the amount of installed natural gas-fired generation and an increase in overall nuclear capacity as the Bruce A units are restarted. During the same period, the Preliminary Plan sees steady increases in the amount of CDM and renewable resources. Approximately 15,000 MW of new supply and conservation resources is added during the period. Risks around the implementation and performance of new resources are managed by adjusting the coal replacement plan and imports.

Transmission developments address local area load growth, support the replacement of Ontario's coal-fired fleet and support near-term hydroelectric developments. In addition, transmission work is initiated to enable developments later on in the planning horizon. Examples include preparatory work on transmission to enable future northern hydroelectric developments, to potential future wind developments and to support the integration of future nuclear resources.

Figure 3.1 shows the complete resource picture for the Preliminary Plan. Data for the figure is given in Appendix F, Table 10.5. Resources in Figure 3.1 are illustrated on a cumulative basis and in effective terms. The shading between 2016 and 2027 is to underscore the greater extent of uncertainty in the long term. The resource details are given in the following tables and figures.

Figure 3.1 – Preliminary Plan – Supply and Demand Resources



Source: OPA

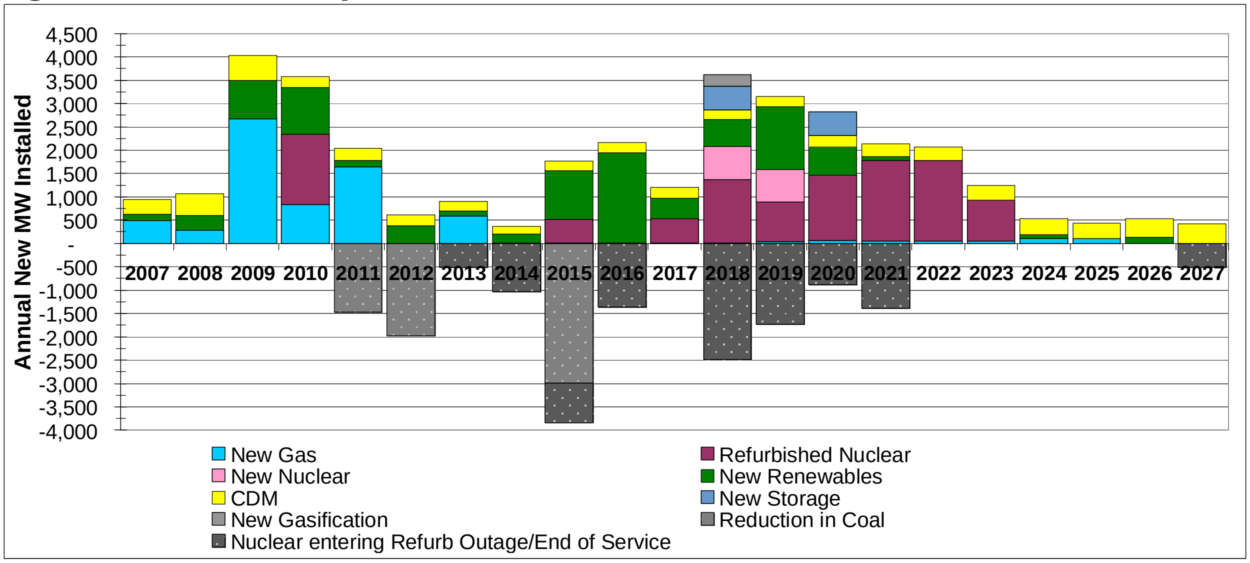
Annual resource additions and reductions, on an installed capacity basis, are given in Figure 3.2 (data is in Table 10.9).

Figure 3.2 illustrates that resource additions in the near-term comprise mostly CDM, natural gas-fired generation and renewables. In the medium-to-long-term, gas additions are modest. Additions beyond the near term consist mostly of CDM, renewable resources, nuclear refurbishments and new nuclear. Reductions in resources reflect the elimination of coal-fired generation by 2015, and nuclear units entering refurbishment outage.

Between 2016 and 2022, the Preliminary Plan enters another period of transition, as eight more nuclear units are refurbished or retired, CDM plays an increasing role in the supply mix and the amount of installed renewable resources nearly doubles from its current level. During the same period, technologies that either do not exist in Ontario's system today, or exist to a limited degree, come into wider use. These include generation storage, gasification, fuel cells and a variety of biomass conversion technologies.

Major transmission enhancements during the period will enable renewable resource developments. Wind power out of the Bruce region and hydroelectric power from the Moose River Basin are examples. New nuclear units are added during this period. Options to address risk around implementation and performance of new resources include firm imports from neighbouring jurisdictions and shorter lead-time options, such as natural gas-fired generation. Opportunities include greater use of emerging technologies and greater than anticipated success in capturing conservation potential.

Figure 3.2 – Preliminary Plan – Resource Additions and Reductions

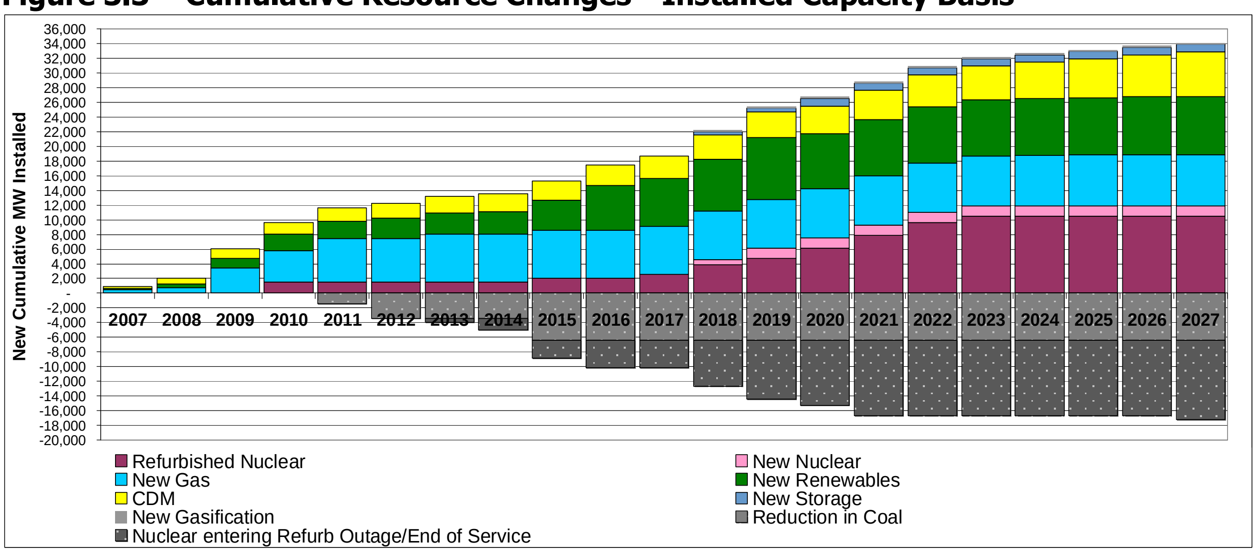


Source: OPA

Cumulative resource additions and reductions, on an installed capacity and effective capacity basis, are given in Figure 3.3 and Figure 3.4, respectively. The corresponding data is given in Table 10.11 and Table 10.12, respectively.

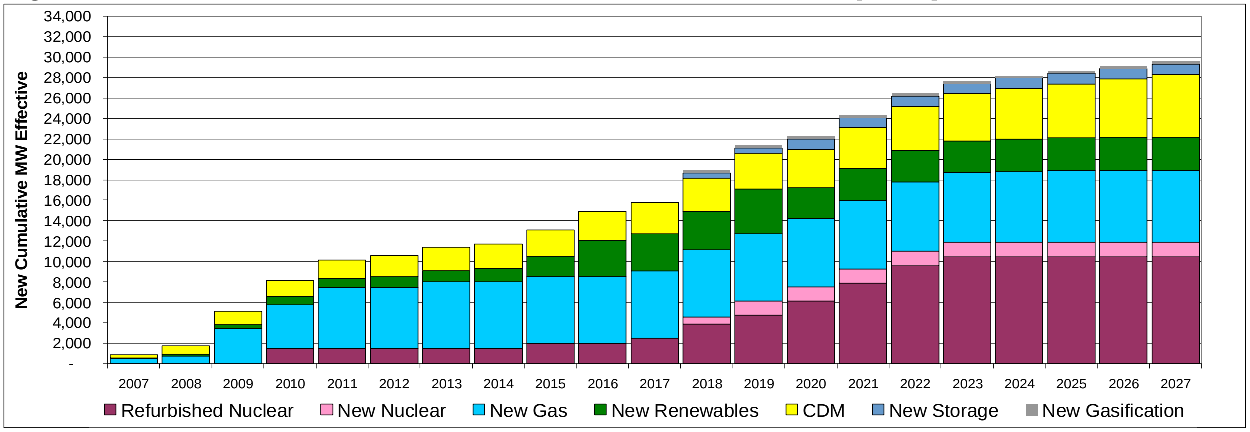
Resource additions and refurbishments between 2007 and 2027 are total about 30,000 MW. Retirements during the same period approach 18,000 MW.

Figure 3.3 – Cumulative Resource Changes - Installed Capacity Basis



Source: OPA

Figure 3.4 – Cumulative Resource Additions – Effective Capacity Basis

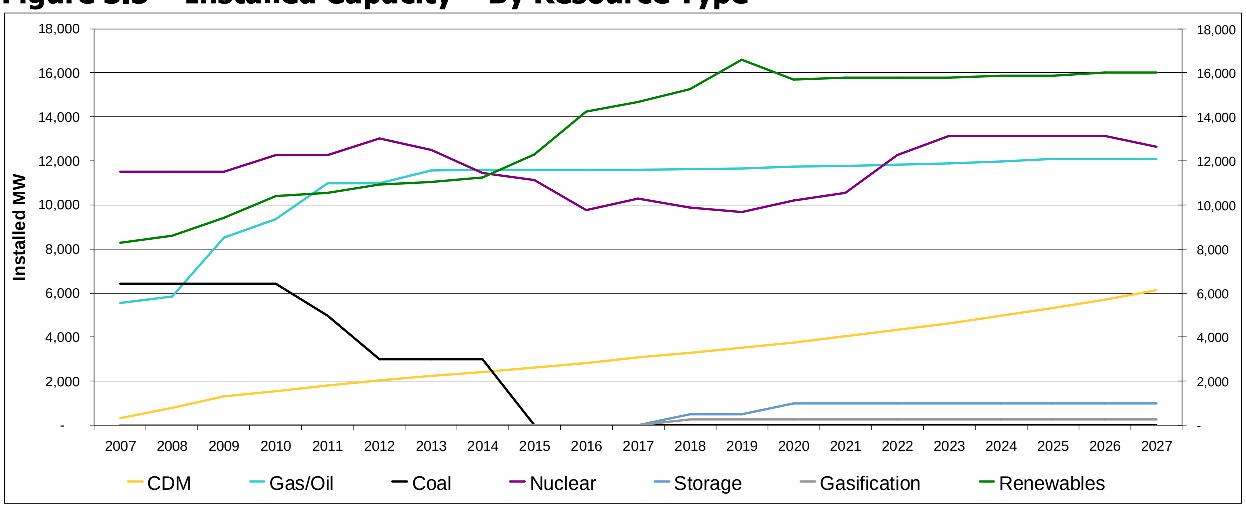


Source: OPA

The composition of the Preliminary Plan over time is illustrated in Figure 3.5 and Figure 3.6 (from data in Table 10.6 and Table 10.5, respectively).

CDM, renewable resources, and natural gas–fired generation see significant increases in installed capacity, whereas coal is removed from service by 2015. Nuclear availability is lowest between 2016 and 2020 when a number of units are simultaneously on refurbishment outages. Storage and gasification emerge towards to medium to long term.

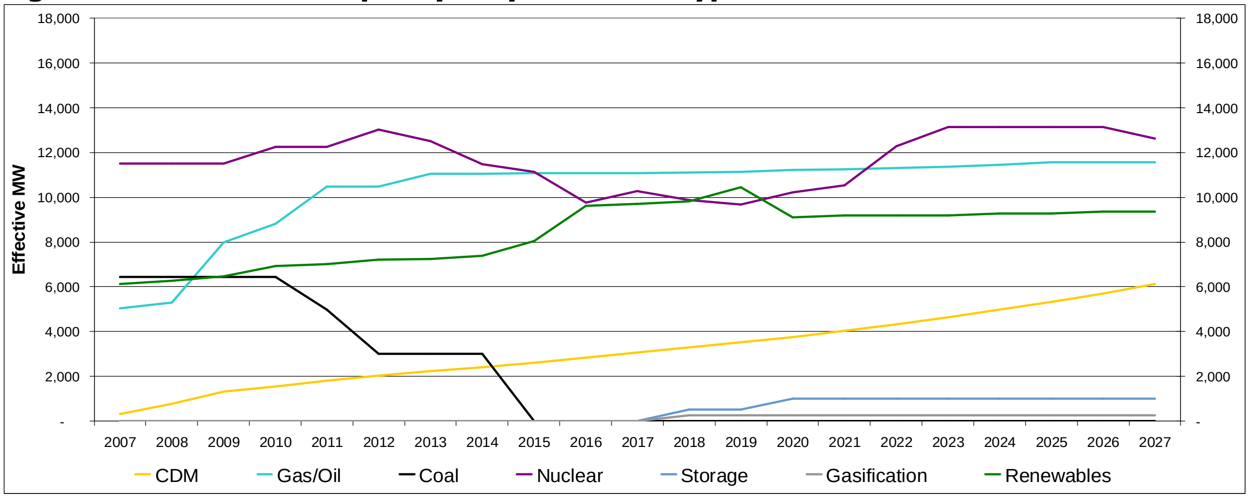
Figure 3.5 – Installed Capacity – By Resource Type



Source: OPA

The third period, from 2023 onwards, is characterized by large uncertainties, including uncertainty around the load forecast, success in capturing resource potentials along for way and technological innovation.

Figure 3.6 – Effective Capacity – By Resource Type



Source: OPA

In the near term, the focus of the Preliminary Plan is on implementing resources that have been committed or are near to being committed, on designing and delivering programs to achieve short-term conservation and renewable energy targets, and on managing near-term risk. The Preliminary Plan during this period also focuses on enabling specific options for implementation in the medium and long terms.

In the medium and long terms, the flexibility of the Preliminary Plan is broader than in the near term. During these periods, the plan seeks to establish and maintain a portfolio of options to address future opportunities, risks and change in general. Options could include the greater use of renewable energy imports from outside Ontario to make up for less than anticipated success in other areas, including success in capturing conservation potential, success in harvesting domestic renewable resource potential, less than expected nuclear performance, higher than anticipated load growth and the potential retirement of existing non-utility generation resources.

Renewable energy imports, as an example, could also serve to reduce the amount of additional natural gas-fired resources required over and above those already committed. Another potential option is hydroelectric development of the Albany River in the medium to long terms, and possibly the development of other rivers in the far north of Ontario.[14] Examples of additional options include greater development of new nuclear resources, greater use of emerging technologies as they become available, enhanced coordination among renewable energy and storage technologies and greater use of CDM.

[14] This refers to the four "Northern Rivers", namely the Albany, Attawapiskat, Winisk and Severn.

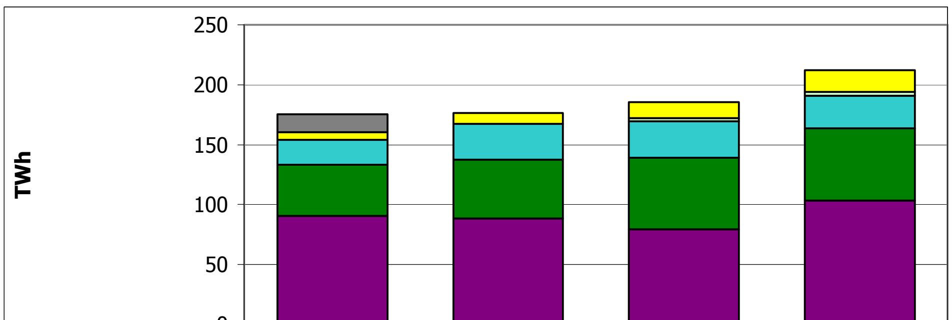
3.1.2 Energy Production

The resources included in the Preliminary Plan and their respective capacity contributions were discussed previously. Corresponding outcomes from an energy production perspective are summarized in the following pages. The results reflect both energy imports and exports with neighbouring jurisdictions.

Figure 3.7 shows production by aggregate resource type for the years 2010, 2015, 2020 and 2025 and Figure 3.8 shows production as a percentage of total production. What the figures show is the following:

- total energy production increases by about 37 TWh between 2010 and 2025, an increase of almost 21 percent
- coal production is eliminated by 2015
- natural gas-fired production increases from 10 percent in 2010 to 17 percent in 2025 and 2020, and then is reduced to 13 percent by 2025
- production from renewable resources increases between 2010 and 2025, and nuclear production is least in 2019 and increases until 2023
- energy conserved represents nine percent of total energy by 2025.

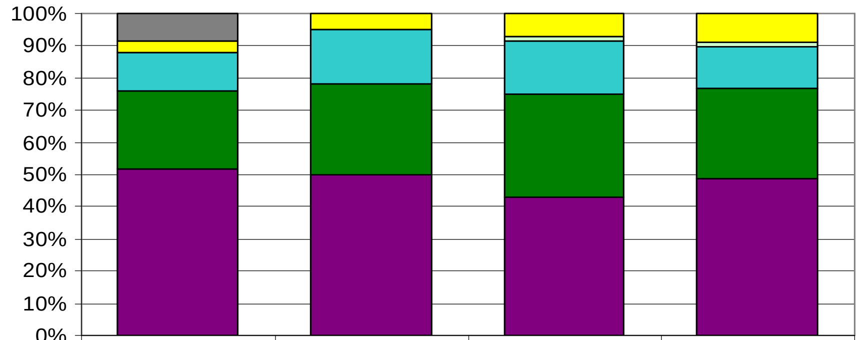
Figure 3.7 – Energy Production and Conservation (TWh)



	2010	2015	2020	2025
Coal	15	0	0	0
CDM	6	9	13	19
Storage & Gasification	0	0	3	3
Gas/Oil	21	30	30	27
Renewables	42	49	60	60
Nuclear	91	88	79	103
Total	175	176	185	212

Source: OPA

Figure 3.8 – Energy Production and Conservation (Percent)



	2010	2015	2020	2025
Coal	9%	0%	0%	0%
CDM	4%	5%	7%	9%
Other	0%	0%	2%	1%
Gas/Oil	12%	17%	16%	13%
Renewables	24%	28%	32%	28%
Nuclear	52%	50%	43%	49%

Source: OPA

Table 3.1 illustrates the change in production by aggregate resource type between 2010 and 2025. By 2025, nuclear production increases by 12.3 TWh, or by about 14 percent, relative to 2010 levels; renewable energy production increases by 18 TWh, or 42 percent; gas/oil production increases by 30 percent; energy conserved increases by 195 percent.

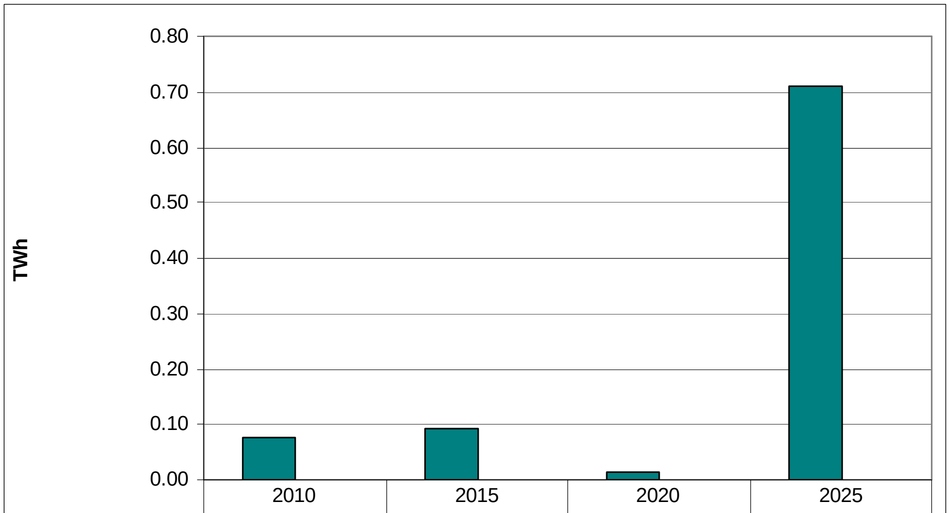
Table 3.1 – Change in Energy Production and Conservation – 2010 to 2025

	TWh Change 2010-2025	Percent Change 2010-2025
CDM	12.4	195
Renewables	18.0	42
Nuclear	12.3	14
Gas/Oil	6.2	30
Storage & Gasification	3.0	–
Coal	(15.0)	-100

Source: OPA

Figure 3.9 shows that supply adequacy requirements are met, with zero "energy not served" over the study period. There is between 0.05 TWh and 0.35 TWh of surplus baseload energy. This is energy that is available in excess of that needed for domestic use or export; Exports e(i.e., energy sold by Ontario to other jurisdictions) over the period exceed imports (i.e., energy sold to Ontario by other jurisdictions). This is illustrated in Figure 3.10.

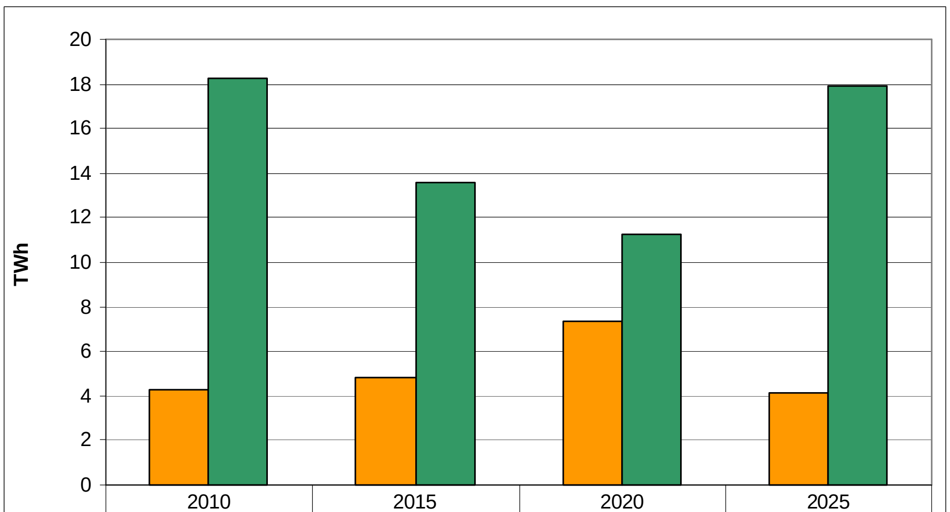
Figure 3.9 – Energy Not Served and Surplus Baseload Production



	2010	2015	2020	2025
Surplus Energy	0.08	0.09	0.01	0.71
Energy Not Served	0.00	0.00	0.00	0.00

Source: OPA

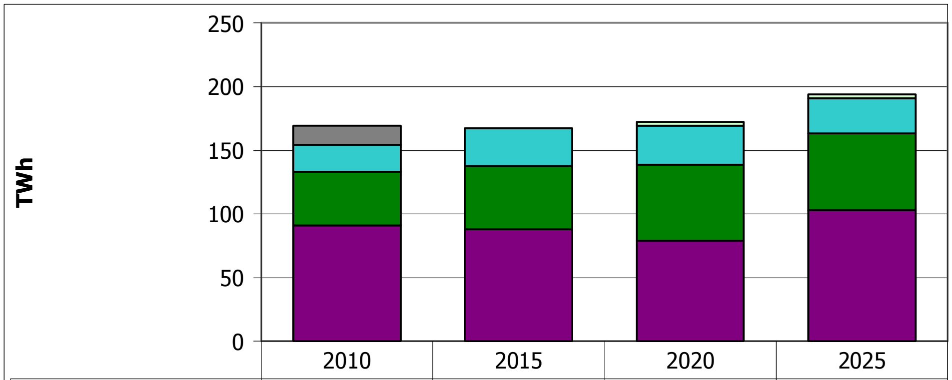
Figure 3.10 – Exports and Imports



	2010	2015	2020	2025
Imports	4	5	7	4
Exports	18	14	11	18

Source: OPA

Figure 3.11 – Energy Production Excluding CDM(TWh)

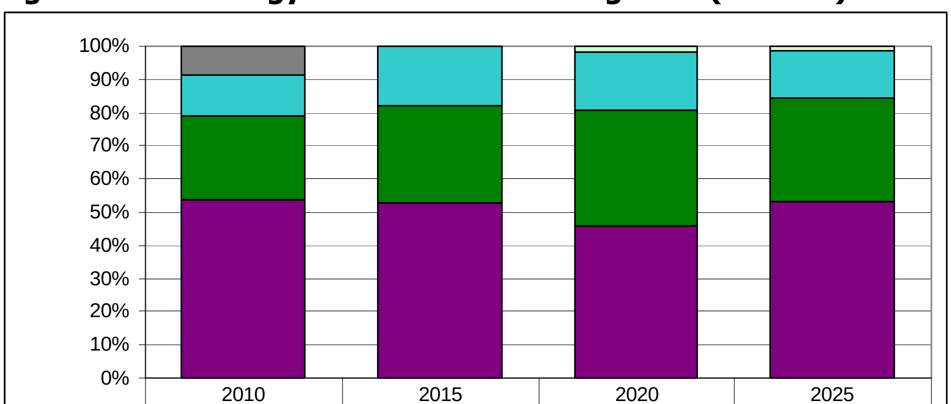


	2010	2015	2020	2025
Coal	15	0	0	0
Storage & Gasification	0	0	3	3
Gas/Oil	21	30	30	27
Renewables	42	49	60	60
Nuclear	91	88	79	103
Total	169	167	172	194

Source: OPA

Figure 3.11 and Figure 3.12 illustrate the production and share of production from generation resources only (i.e., not including energy conserved). The same general trend is seen as that described above.

Figure 3.12 – Energy Production Excluding CDM (Percent)

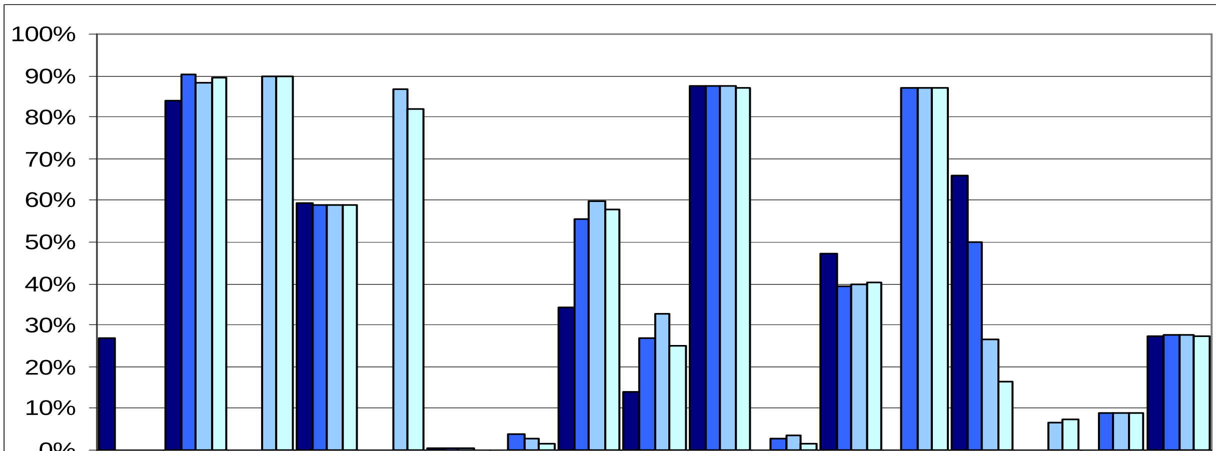


	2010	2015	2020	2025
Coal	9%	0%	0%	0%
Other	0%	0%	2%	2%
Gas/Oil	12%	18%	18%	14%
Renewables	25%	29%	35%	31%
Nuclear	54%	53%	46%	53%

Source: OPA

Annual average capacity factors for major resource types over the planning horizon are illustrated in Figure 3.13.

Figure 3.13 – Capacity Factors of Resources (Percent)



	Coal	Nuclear - Existin	Nuclear - New	Hydro	IGCC	OPG LX	Biomass_Ati	Biomass_Othr	CCGT	Cogen	SCGT	CDM	FuelCell	NUG	Pump Storage	Solar	Wnd
2010	27%	84%	0%	60%	0%	0%	0%	34%	14%	87%	0%	47%	0%	66%	0%	0%	27%
2015	0%	90%	0%	59%	0%	0%	4%	55%	27%	87%	3%	40%	87%	50%	0%	9%	28%
2020	0%	88%	90%	59%	87%	0%	3%	60%	33%	87%	3%	40%	87%	26%	7%	9%	28%
2025	0%	89%	90%	59%	82%	0%	2%	58%	25%	87%	2%	40%	87%	16%	7%	9%	28%

Source: OPA

3.1.3 Transmission

The transmission facilities included in the Preliminary Plan were described in detail in the transmission paper (#5) and the associated actions and decisions are given in sections 2 and 4 of this paper.

These transmission facilities meet applicable reliability standards. The supply and conservation resources were seen to provide adequate capacity and energy production to satisfy demand requirements. When these are taken with the associated transmission facilities, the resulting system described in the Preliminary Plan is therefore judged to meet the feasibility and reliability criteria.

3.2 Preliminary Plan - Cost Perspective

This section describes the costs that customers are likely to see on their bills as the plan is developed. It also explains how the value of conservation is determined, which in turn affects cost to customers.

The cost results in this section reflect initial estimates. There are many conditions and circumstances that could move costs below or above these estimates. In order to reflect this uncertainty, some reasonable ranges have been provided.

3.2.1 Cost to Customer

The customer cost implications of the Preliminary Plan are shown in this section. They are based on the methodology described in Appendix C.

As explained in Appendix C, the cost of service to customers is made up of commodity (electricity), delivery (transmission and distribution), wholesale market services (ancillary services, fees), conservation and debt retirement. This section estimates each of these components and associated assumptions.

We begin with the commodity costs analysis. It is important to recognize that these are not price forecasts, but rather an analysis of the cost components and assumptions about their costs.

The first step to this analysis is to unbundle the energy produced over time into facility types that share similar commercial or cost characteristics. For example, Renewable Energy Supply contracts, refurbished nuclear energy and standard offer contracts can be organized into groups.

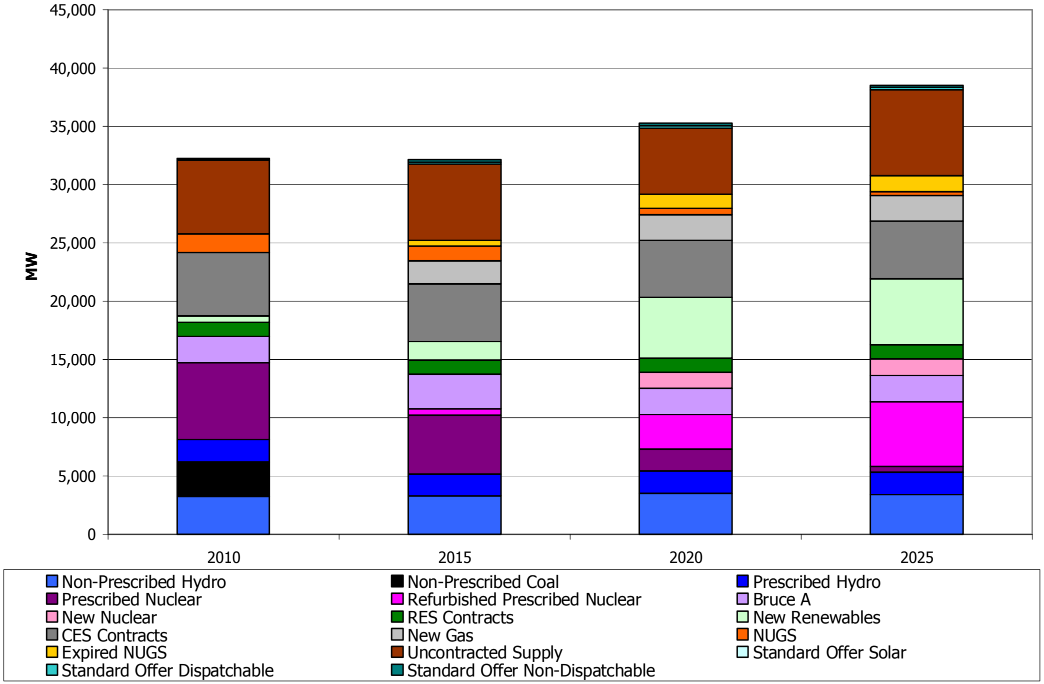
Figure 3.14 and Figure 3.15 show the capacity and energy associated with these categories and how they evolve over time. The limitation of projecting this unbundling into the future is the uncertainty in the medium and long terms, and how the system will actually evolve.

The cost to customer tables and graphs provide estimates for 2005 based on IESO data. This data is still in the process of being validated, and thus the numbers are approximate. Certain approximations are inherent in the process of developing the data provided by the IESO to align with the cost categories presented. As refinements are carried out, updated numbers will be made available.

The next step provides explicit estimates for the cost of the various unbundled categories. This is an estimate of the cost of the services, based primarily on current estimates of cost that are useful to project into the future; this is not a prediction of exactly how the electricity will be sold, or under what commercial or settlement mechanism. It may be sold through bilateral agreements between buyers and sellers, or load-serving entities and generators, or the OPA and generators or on a regulated basis or any other yet to be developed market mechanism. The key value of the analysis is to provide estimates of the costs, however settled, and under any combination of market or regulated arrangements and under various commercial arrangements.

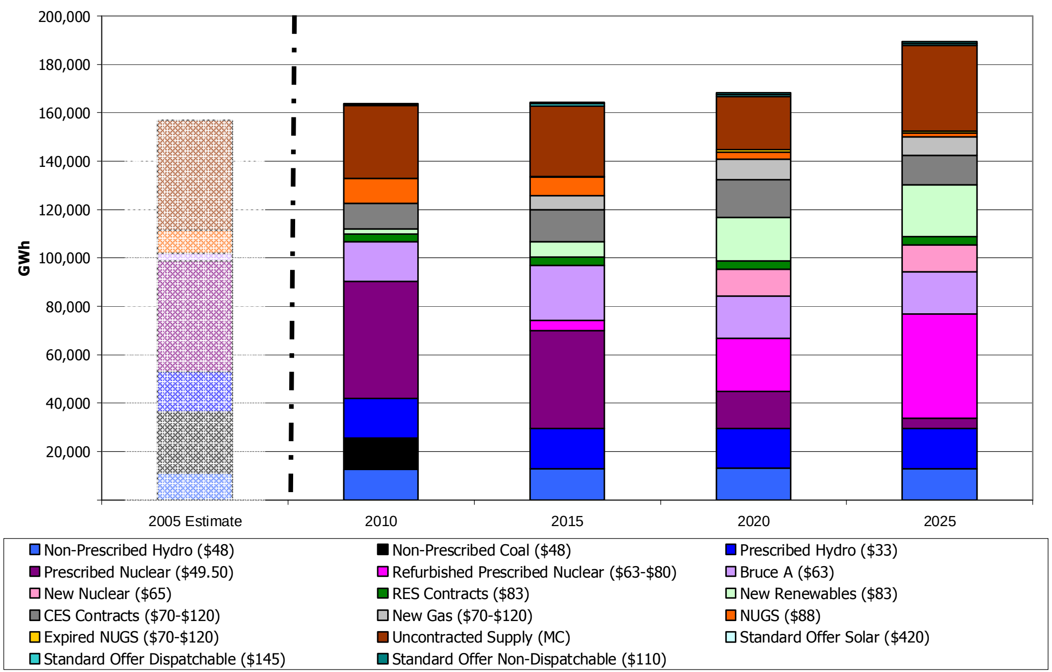
Given the uncertainty of future costs the analysis utilizes an upper and lower band of the cost components. This is intended to demonstrate uncertainty associated with possible future outcomes.

Figure 3.14 – Total Capacity Unbundled into Various Cost Categories



Source: OPA

Figure 3.15 – Total Generation Produced by Various Cost Categories



Source: OPA

Despite the many simplifications, we see trends emerging that bracket a credible range of possible generation cost implications on customers. There will likely be scenarios that take the costs outside this range. The explicit assumptions made in this analysis make it transparent and easy to incorporate different assumptions. These assumptions are shown in Table 3.2, Table 3.3 and Table 3.4.

Table 3.2 – Assumed Electricity Commodity Costs by Facility Type

	2006 $/MWH						
	Lower Bound	Upper Bound	2005 Est	2010	2015	2020	2025
Non-Prescribed Hydro	$48.00	$48.00					
Non-Prescribed OPG Coal	$48.00	$48.00					
Prescribed Hydro	$33.00	$33.00					
Prescribed Nuclear	$49.50	$49.50					
Refurbished Prescribed Nuclear	$63.00	$80.00					
Bruce A	$63.00	$63.00					
NUGS	$88.00	$88.00					
Expired NUGS	$90.00	$120.00					
*OPA CES Contracts	$90.00	$120.00					
OPA RES Contracts	$83.00	$83.00					
New Nuclear	$65.00	$80.00					
New Renewables	$85.00	$85.00					
New Gas	$90.00	$120.00					
Standard Offer Dispatchable	$145.00	$145.00					
Standard Offer Non-Dispatchable	$110.00	$110.00					
Standard Offer Solar	$420.00	$420.00					
Uncontracted Supply - Lower Bound			$72.14	$39.00	$53.00	$56.00	$51.00
Uncontracted Supply - Upper Bound			$72.14	$59.00	$73.00	$76.00	$71.00

Source: OPA

Table 3.3 – Summary of Generation Assumptions – Lower Bound

	2010					2015				
	**Capacity (MW)	Production (TWh)	% of Production	Cost $2006M	% of Cost	**Capacity (MW)	Production (TWh)	% of Production	Cost $2006M	% of Cost
Non-Prescribed Hydro	3,255	13	7.8%	612	7%	3,284	13	7.9%	626	6%
Non-Prescribed Coal	2,968	13	7.8%	613	7%					
Prescribed Hydro	1,900	16	10.0%	541	6%	1,900	16	10.0%	543	6%
Prescribed Nuclear	6,606	49	29.6%	2,401	27%	5,058	40	24.6%	2,001	20%
Refurbished Prescribed Nuclear						516	4	2.6%	267	3%
Bruce A	2,250	16	9.9%	1,025	12%	3,000	23	13.9%	1,438	15%
NUGS	1,600	10	6.3%	903	10%	1,269	7	4.5%	655	7%
Expired NUGS	2	0	0.0%	4	0%	496	0	0.2%	33	0%
***OPA CES Contracts	5,459	11	6.4%	951	11%	4,949	13	7.9%	1,175	12%
OPA RES Contracts	1,202	3	2.0%	276	3%	1,202	3	2.0%	276	3%
New Nuclear										
New Renewables	529	2	1.3%	176	2%	1,591	7	4.0%	553	6%
New Gas						1,936	6	3.7%	546	6%
Standard Offer Dispatchable	100	0	0.2%	58	1%	196	1	0.5%	116	1%
Standard Offer Non-Dispatchable	100	0	0.2%	44	1%	196	1	0.5%	88	1%
Standard Offer Solar							0	0.0%	0	0%
Uncontracted Supply	6,297	30	18.4%	1,176	13%	6,541	29	17.7%	1,543	16%
	32,268	**164**	**100%**	**8,781**	**100%**	**32,135**	**164**	**100%**	**9,859**	**100%**
			Average Cost	**$53.57**	**/MWh**			**Average Cost**	**$59.96**	**/MWh**

	2020					2025				
	**Capacity (MW)	Production (TWh)	% of Production	Cost $2006M	% of Cost	**Capacity (MW)	Production (TWh)	% of Production	Cost $2006M	% of Cost
Non-Prescribed Hydro	3,525	13	7.8%	629	5.8%	3,407	13	6.8%	623	5%
Non-Prescribed Coal										
Prescribed Hydro	1,900	16	9.8%	544	5%	1,900	16	8.7%	542	5%
Prescribed Nuclear	1,908	15	9.0%	750	7%	515	4	2.2%	209	2%
Refurbished Prescribed Nuclear	2,942	22	13.2%	1,395	13%	5,576	43	22.8%	2,720	23%
Bruce A	2,250	17	10.3%	1,097	10%	2,250	18	9.3%	1,106	9%
NUGS	556	3	1.7%	258	2%	349	2	0.9%	151	1%
Expired NUGS	1,173	1	0.6%	97	1%	1,325	1	0.4%	74	1%
***OPA CES Contracts	4,949	15	9.2%	1,390	13%	4,949	12	6.3%	1,080	9%
OPA RES Contracts	1,202	3	2.0%	277	3%	1,202	3	1.8%	276	2%
New Nuclear	1,400	11	6.6%	720	7%	1,400	11	5.8%	718	6%
New Renewables	5,168	18	10.8%	1,539	14%	5,678	22	11.4%	1,833	15%
New Gas	2,186	9	5.1%	765	7%	2,186	8	4.1%	695	6%
Standard Offer Dispatchable	196	1	0.5%	116	1%	196	1	0.4%	116	1%
Standard Offer Non-Dispatchable	196	1	0.5%	88	1%	196	1	0.4%	88	1%
Standard Offer Solar		0	0.0%	0	0%		0	0.0%	0	0%
*Uncontracted Supply	5,691	22	13.0%	1,225	11%	7,391	35	18.6%	1,801	15%
	35,242	**168**	**100%**	**10,889**	**100%**	**38,521**	**189**	**100%**	**12,031**	**100%**
			Average Cost	**$64.73**	**/MWh**			**Average Cost**	**$63.50**	**/MWh**

Notes:
*Uncontracted Supply includes Bruce B, Lennox Non base load regulated hydro, expired CES contracts as well as additional renewable resources.
**Capacity is the greatest availability of MW of each facility in a given year as per the Henwood results.
***OPA CES contracts includes all gas related committed supply resources shown in Table 2.1 as well as natural gas facilities.
Source: OPA

Table 3.4 – Summary of Generation Assumptions – Higher Bound

	2010					2015				
	**Capacity (MW)	Production (TWh)	% of Production	Cost $2006M	% of Cost	**Capacity (MW)	Production (TWh)	% of Production	Cost $2006M	% of Cost
Non-Prescribed Hydro	3,255	13	7.8%	612	6%	3,284	13	7.9%	626	6%
Non-Prescribed Coal	2,968	13	7.8%	613	6%					
Prescribed Hydro	1,900	16	10.0%	541	5%	1,900	16	10.0%	543	5%
Prescribed Nuclear	6,606	49	29.6%	2,401	24%	5,058	40	24.6%	2,001	18%
Prescribed Regulated Nuclear						516	4	2.6%	339	3%
Bruce A	2,250	16	9.9%	1,025	10%	3,000	23	13.9%	1,438	13%
NUGS	1,600	10	6.3%	903	9%	1,269	7	4.5%	655	6%
Expired NUGS	2	0	0.0%	5	0%	496	0	0.2%	45	0%
***OPA CES Contracts	5,459	11	6.4%	1,268	13%	4,949	13	7.9%	1,566	14%
OPA RES Contracts	1,202	3	2.0%	276	3%	1,202	3	2.0%	276	2%
New Nuclear										
New Renewables	529	2	1.3%	176	2%	1,591	7	4.0%	553	5%
New Gas						1,936	6	3.7%	727	7%
Standard Offer Dispatchable	100	0	0.2%	58	1%	196	1	0.5%	116	1%
Standard Offer Non-Dispatchable	100	0	0.2%	44	0%	196	1	0.5%	88	1%
Standard Offer Solar							0	0.0%	0	0%
Uncontracted Supply	6,297	30	18.4%	2,176	22%	6,541	29	17.7%	2,100	19%
	32,268	**164**	**100%**	**10,099**	**100%**	**32,135**	**164**	**100%**	**11,073**	**100%**
			Average Cost	**$61.61**	**/MWh**			**Average Cost**	**$67.34**	**/MWh**

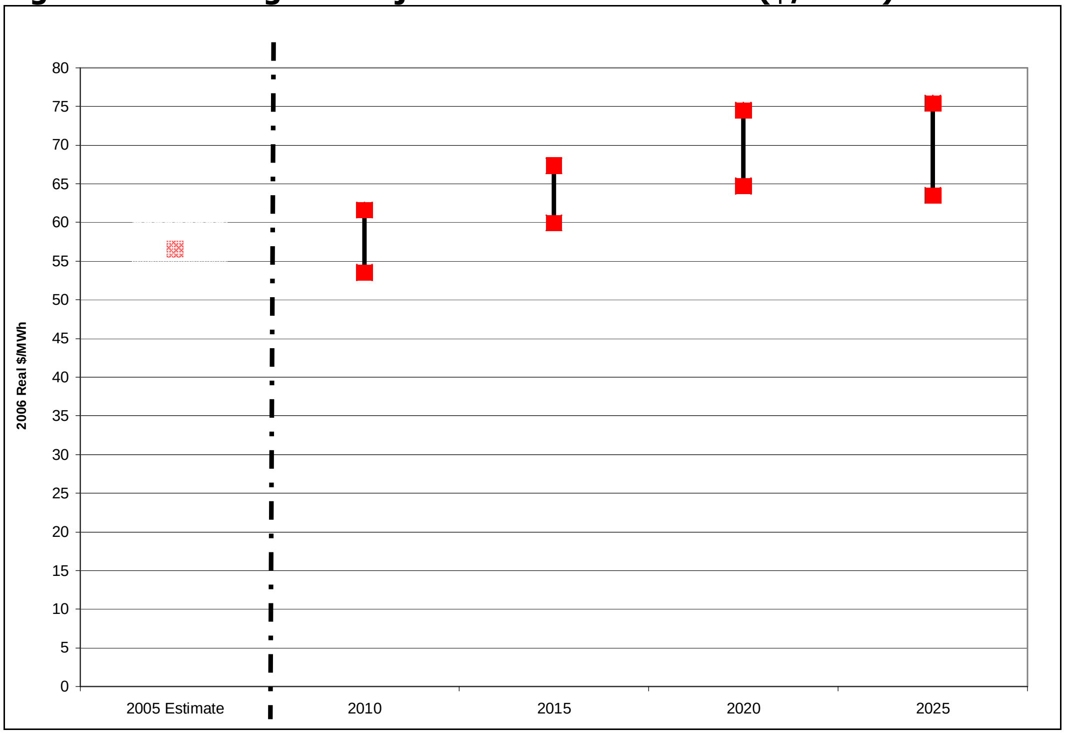
	2020					2025				
	**Capacity (MW)	Production (TWh)	% of Production	Cost $2006M	% of Cost	**Capacity (MW)	Production (TWh)	% of Production	Cost $2006M	% of Cost
Non-Prescribed Hydro	3,525	13	7.8%	629	5.0%	3,407	13	6.8%	623	4%
Non-Prescribed Coal										
Prescribed Hydro	1,900	16	9.8%	544	4%	1,900	16	8.7%	542	4%
Prescribed Nuclear	1,908	15	9.0%	750	6%	515	4	2.2%	209	1%
Prescribed Regulated Nuclear	2,942	22	13.2%	1,772	14%	5,576	43	22.8%	3,453	24%
Bruce A	2,250	17	10.3%	1,097	9%	2,250	18	9.3%	1,106	8%
NUGS	556	3	1.7%	258	2%	349	2	0.9%	151	1%
Expired NUGS	1,173	1	0.6%	129	1%	1,325	1	0.4%	99	1%
***OPA CES Contracts	4,949	15	9.2%	1,853	15%	4,949	12	6.3%	1,441	10%
OPA RES Contracts	1,202	3	2.0%	277	2%	1,202	3	1.8%	276	2%
New Nuclear	1,400	11	6.6%	886	7%	1,400	11	5.8%	883	6%
New Renewables	5,168	18	10.8%	1,539	12%	5,678	22	11.4%	1,833	13%
New Gas	2,186	9	5.1%	1,020	8%	2,186	8	4.1%	926	6%
Standard Offer Dispatchable	196	1	0.5%	116	1%	196	1	0.4%	116	1%
Standard Offer Non-Dispatchable	196	1	0.5%	88	1%	196	1	0.4%	88	1%
Standard Offer Solar		0	0.0%	0	0%		0	0.0%	0	0%
Uncontracted Supply	5,691	22	13.0%	1,578	13%	7,391	35	18.6%	2,547	18%
	35,242	**168**	**100%**	**12,535**	**100%**	**38,521**	**189**	**100%**	**14,293**	**100%**
			Average Cost	**$74.51**	**/MWh**			**Average Cost**	**$75.44**	**/MWh**

Notes:
*Uncontracted Supply includes Bruce B, Lennox Non base load regulated hydro, expired CES contracts as well as additional renewable resources.
**Capacity is the greatest availability of MW of each facility in a given year as per the Henwood results.
***OPA CES contracts includes all gas related committed supply resources shown in Table 2.1 as well as natural gas facilities.
Source: OPA

The lower and upper generation costs are produced as a product of production multiplied by the electricity commodity costs. Figure 3.16 illustrates the range of generation costs.

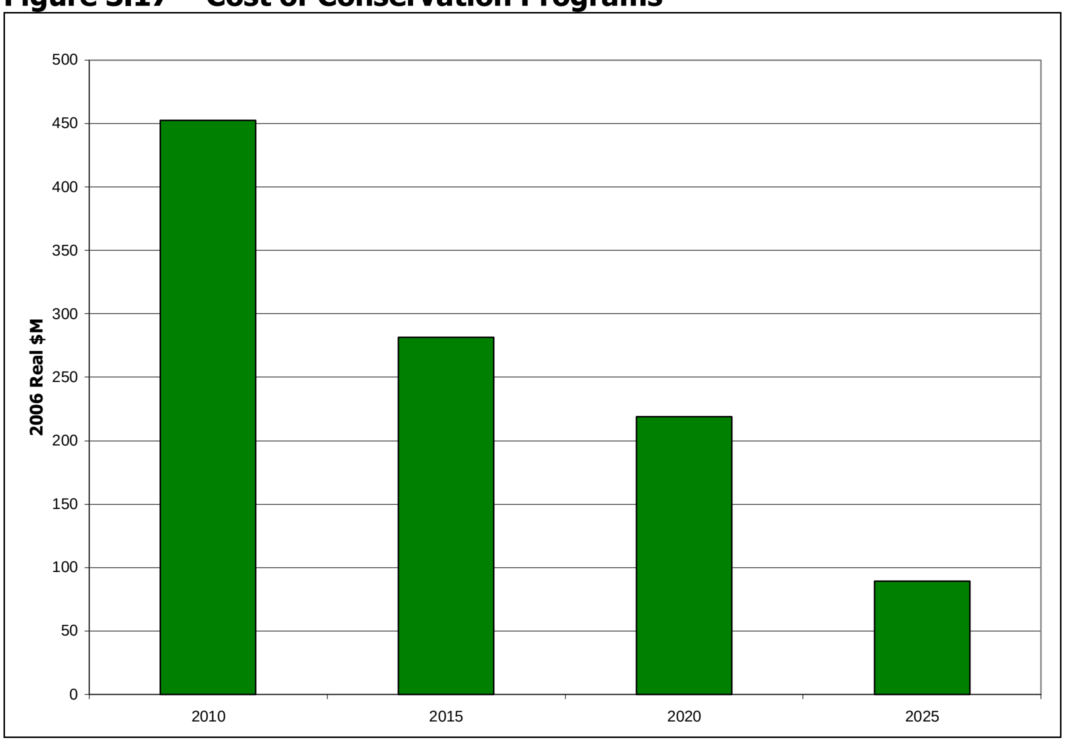
We next move to providing estimates of conservation cost (Figure 3.17), transmission (Figure 3.18 and Figure 3.19), wholesale market services (Figure 3.20 and Figure 3.21), debt retirement costs (Figure 3.22 and Figure 3.23), and distribution costs (Figure 3.24 and Figure 3.25).

Figure 3.16 – Range of Projected Generation Costs ($/MWh)



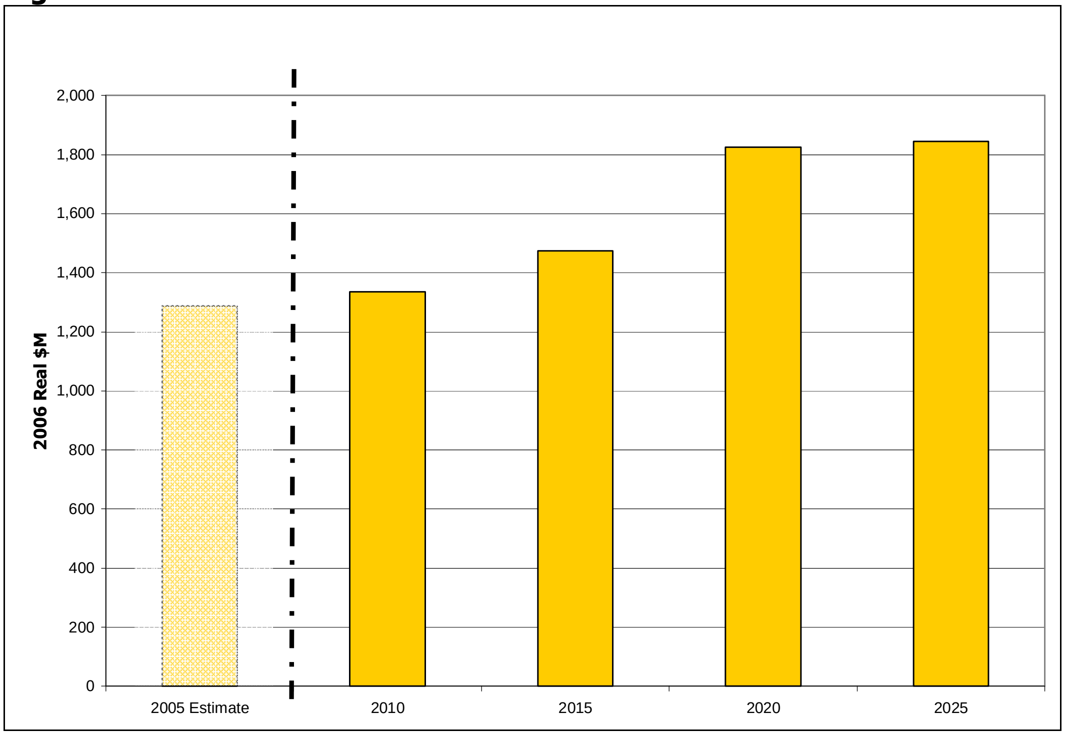
Source: OPA

Figure 3.17 – Cost of Conservation Programs



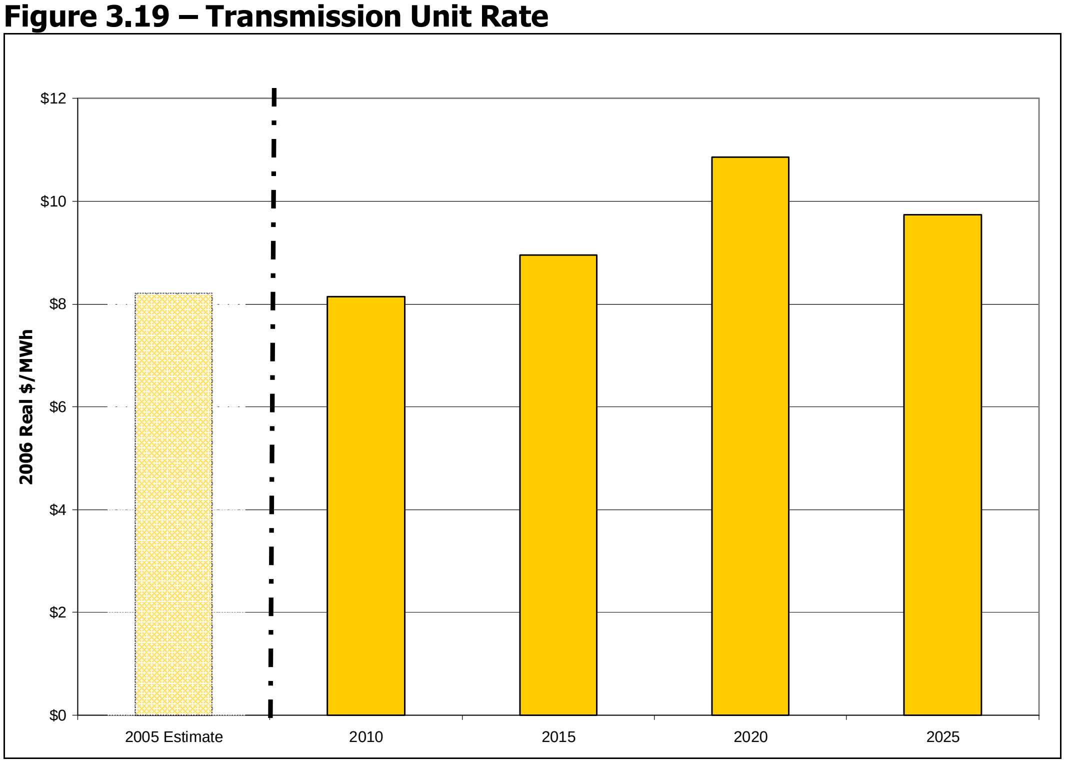
Source: OPA

Figure 3.18 – Cost of Transmission



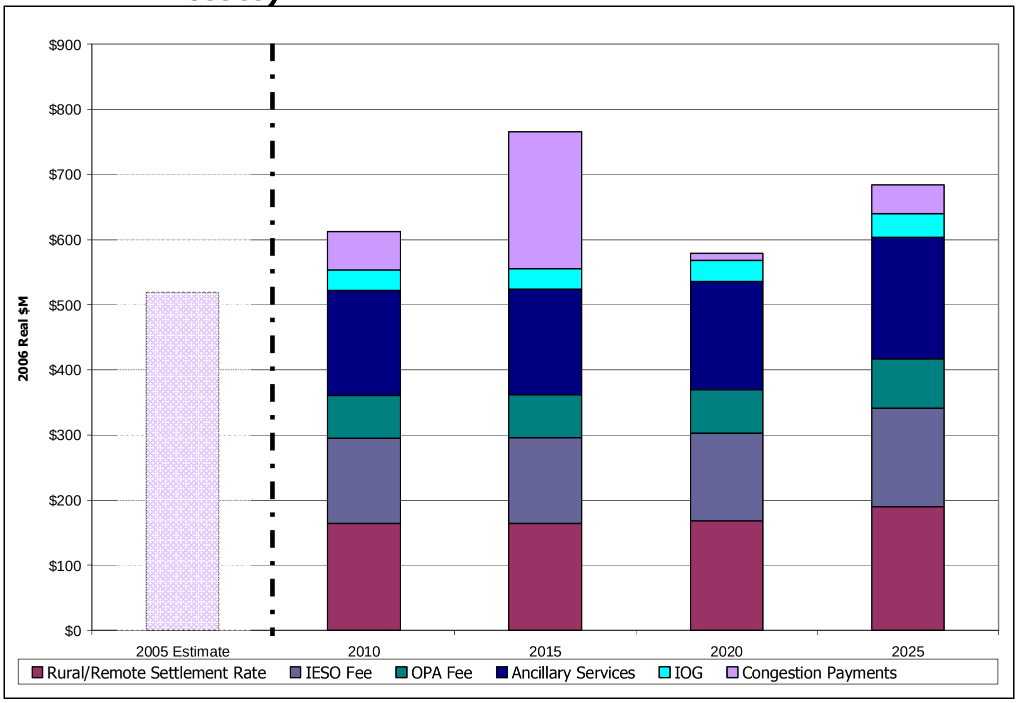
Source: OPA

Figure 3.19 – Transmission Unit Rate



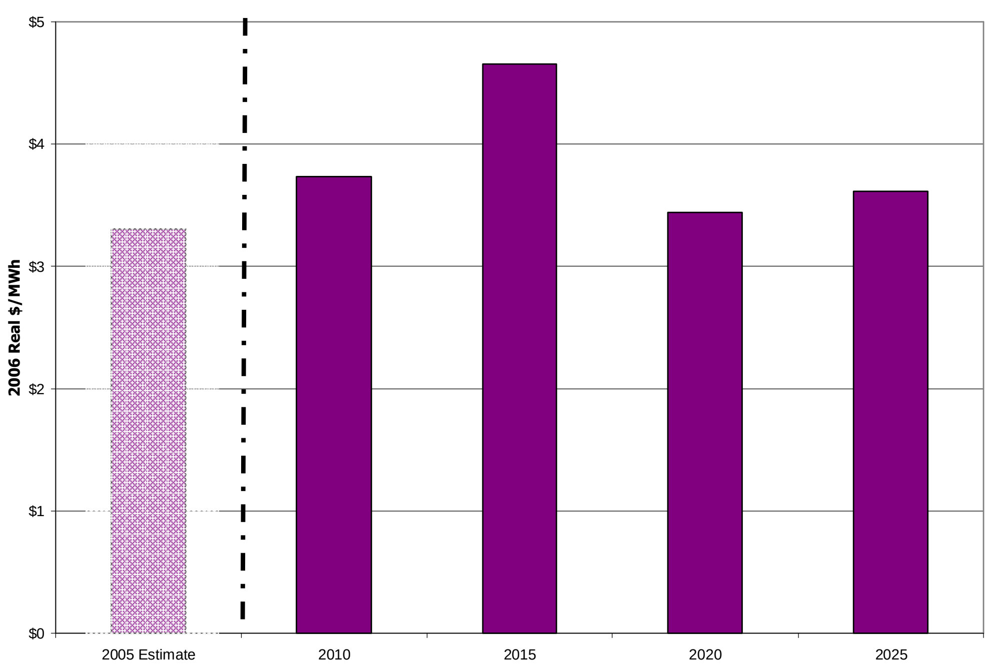
Source: OPA

Figure 3.20 – Cost of Wholesale Market Service Charges (except for losses)



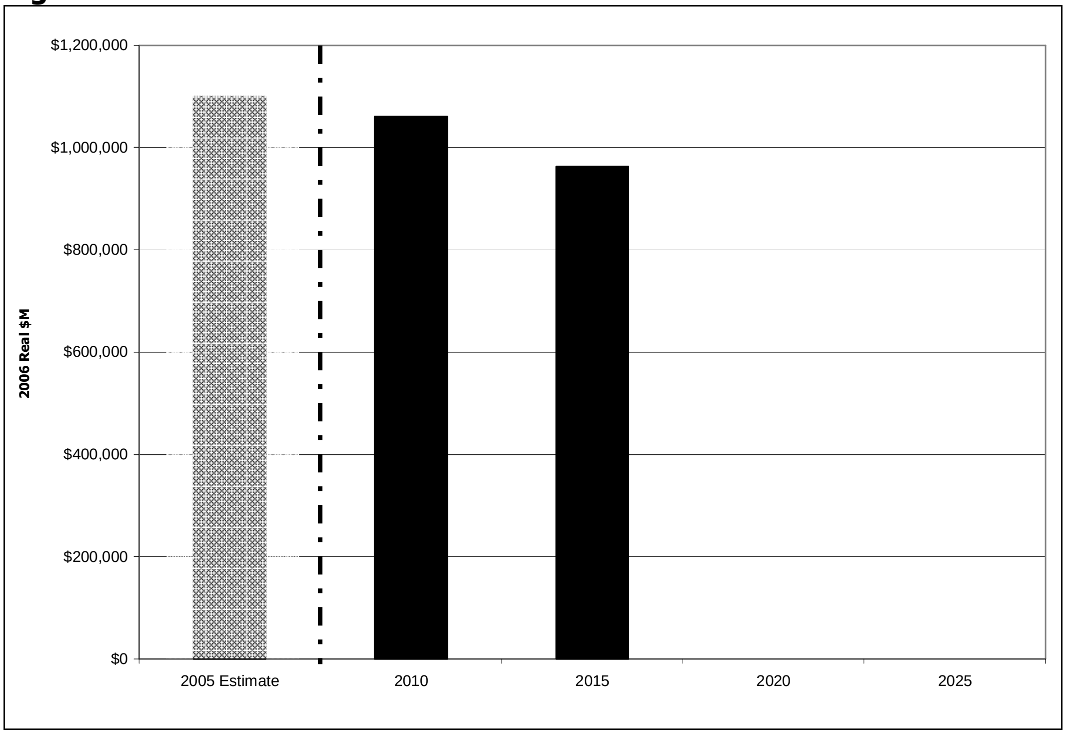
Source: OPA

Figure 3.21 – Wholesale Market Service Unit Rate (except for losses)



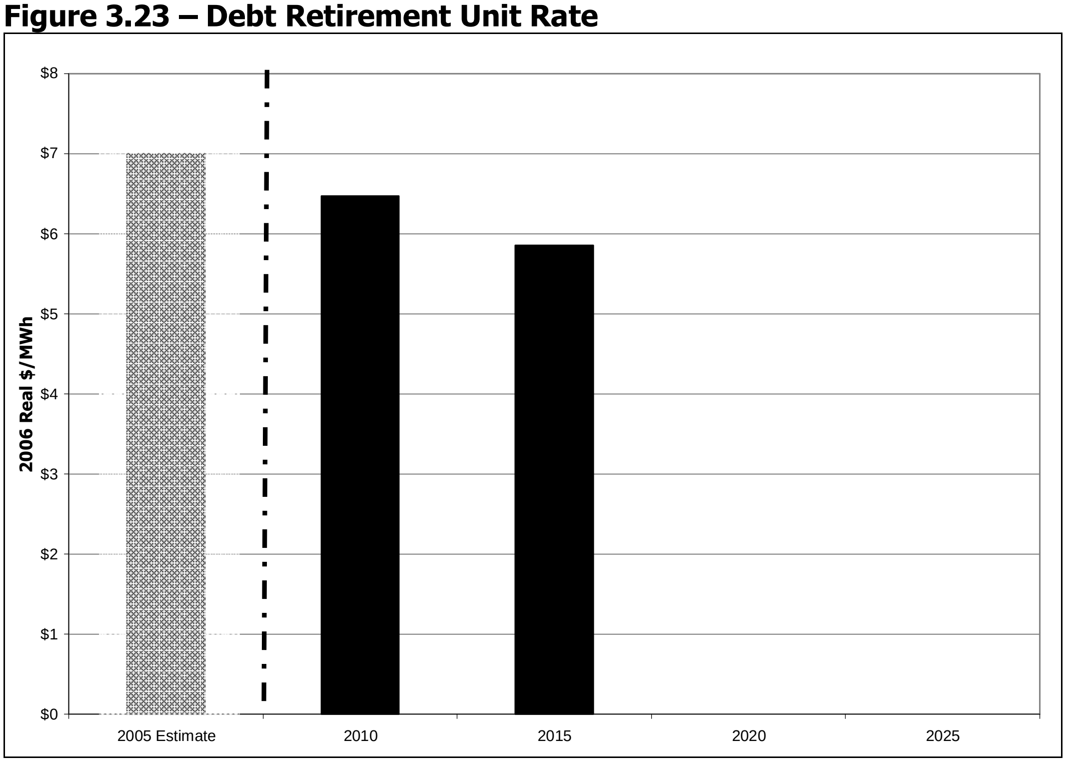
Source: OPA

Figure 3.22 – Cost of Debt Retirement



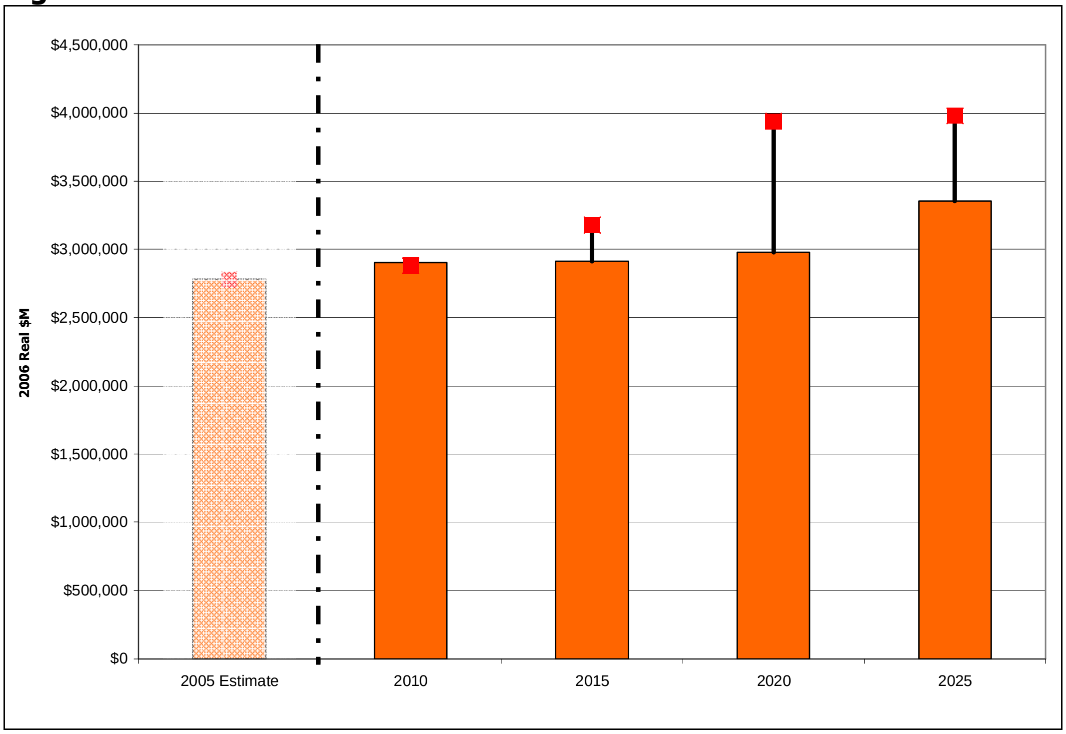
Source: OPA

Figure 3.23 – Debt Retirement Unit Rate



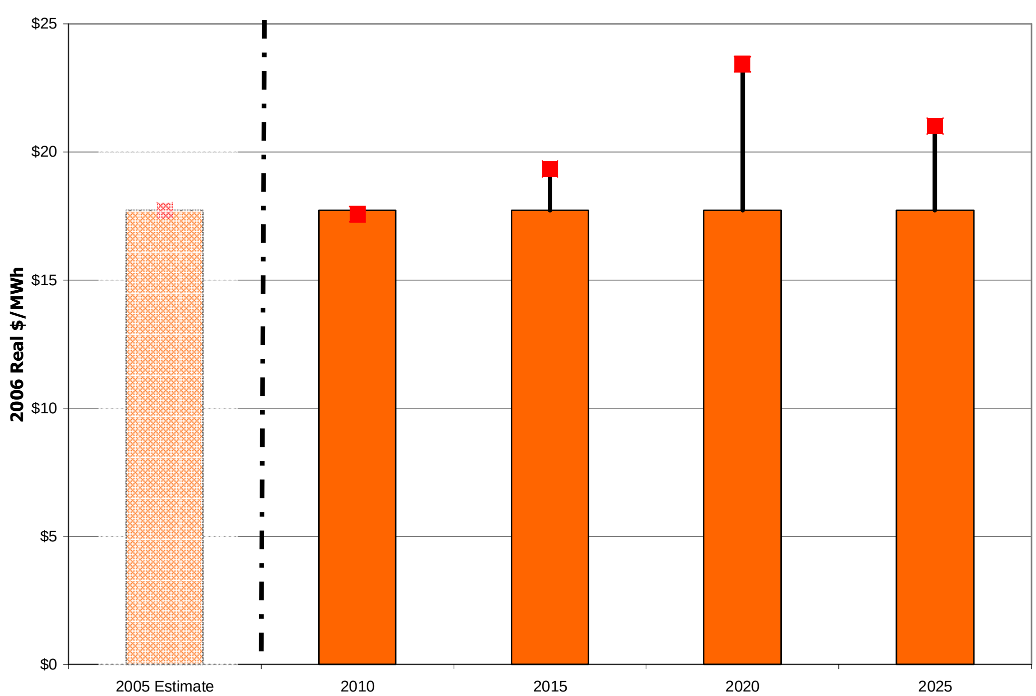
Source: OPA

Figure 3.24 – Cost of Distribution



Source:

Figure 3.25 – Distribution Unit Rate



Source:

Now that each of the components has been estimated, we stack all the components together. Figure 3.26 and Table 3.5 shows the total unit cost in $/MWh.

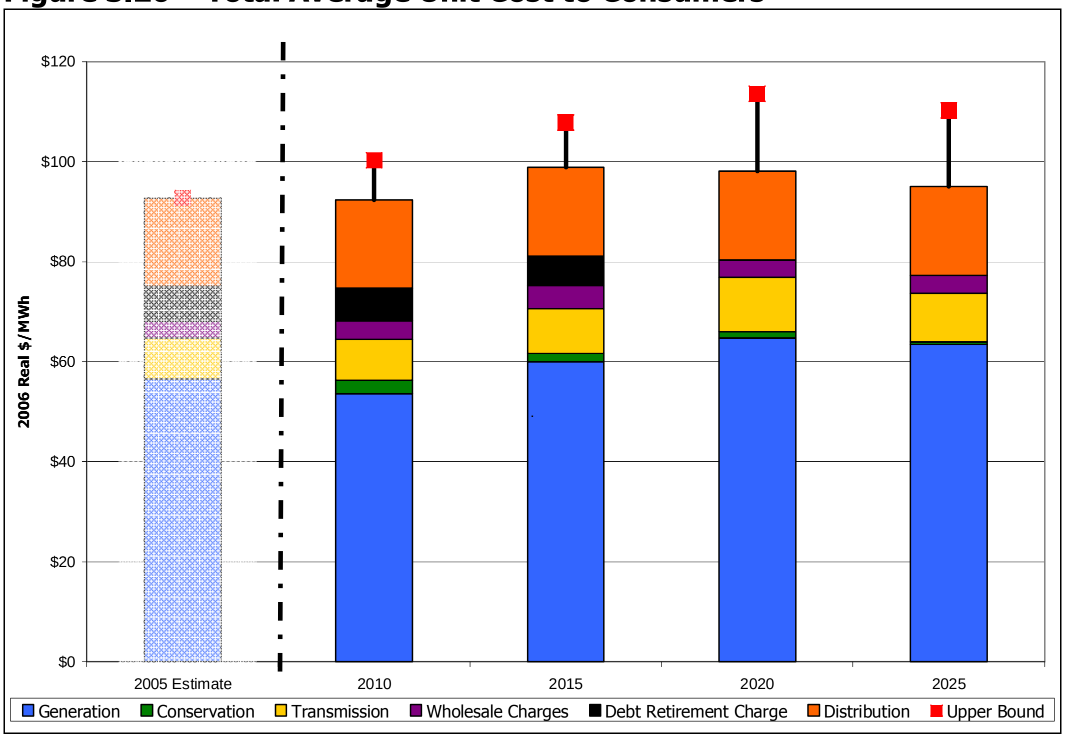
The cost per MWh as shown in Table 3.5 is used to estimate a typical household bill. The typical household bill analysis is illustrative and impacts will be different for various customers, according to their consumption patterns, levels of conservation, time of use, local service terms and conditions, and contracts they may enter into for services. The results are based an assumed current monthly bill of $100.

Figure 3.27 shows a decline in the householder bill for the lower bound case. Figure 3.28 shows that for the upper bound case, the bill will increase, or remain constant under proactive implementation of CDM measures.

The factors responsible for these trends include:

- the debt retirement charge on householders' bills will be paid down by 2020 and eliminated at that time
- the volume of energy used in a typical household declines due to naturally occurring or proactive implementation of CDM.

Figure 3.26 – Total Average Unit Cost to Consumers



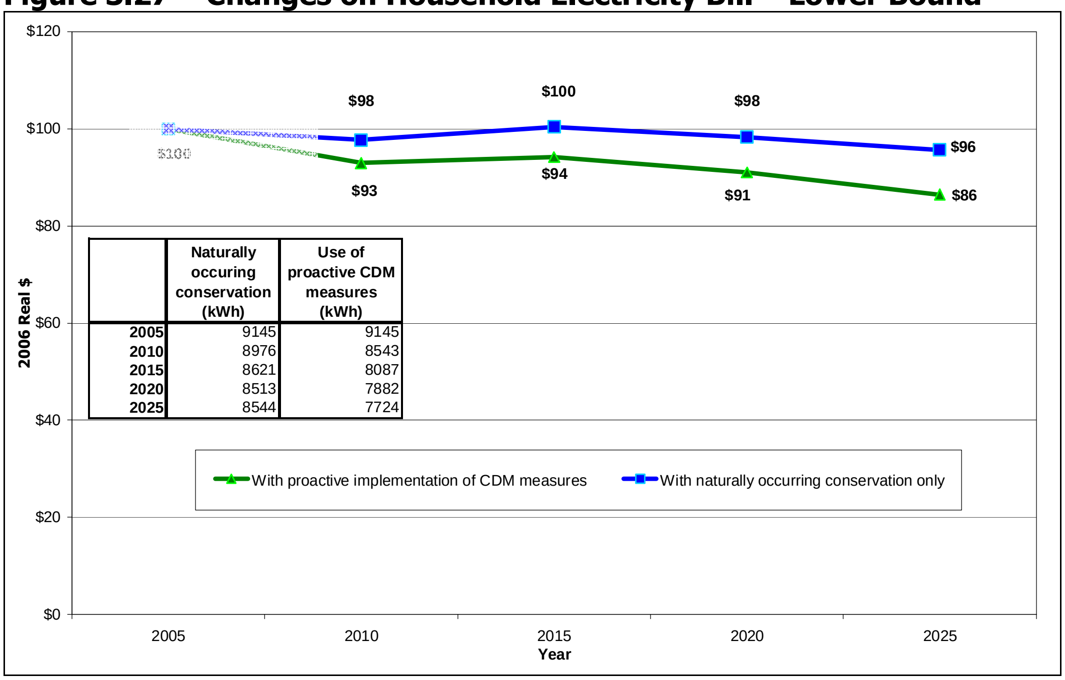
Source: OPA

Table 3.5 – Components of Cost to Customer Analysis

	UNIT RATES ($2006/MWh)				
LOWER BOUND	2005 Estimate	2010	2015	2020	2025
Conservation		$2.76	$1.71	$1.30	$0.47
Transmission	$8.21	$8.15	$8.96	$10.86	$9.74
Wholesale	$3.31	$3.74	$4.66	$3.44	$3.61
Debt Retirement Charge	$7.00	$6.47	$5.86		
Distribution Lower Bound	$17.71	$17.71	$17.71	$17.71	$17.71
Generation Lower Bound	$56.58	$53.57	$59.96	$64.73	$63.50
UPPER BOUND					
Conservation		$2.76	$1.71	$1.30	$0.47
Transmission	$8.21	$8.15	$8.96	$10.86	$9.74
Wholesale	$3.31	$3.74	$4.66	$3.44	$3.61
Debt Retirement Charge	$7.00	$6.47	$5.86		
Distribution Upper Bound	$17.71	$17.58	$19.33	$23.43	$21.01
Generation Upper Bound	$56.58	$61.61	$67.34	$74.51	$75.44
Total Cost to Customer - LOWER	$92.80	$92.38	$98.85	$98.03	$95.03
Total Cost to Customer - UPPER	**$92.80**	**$100.29**	**$107.85**	**$113.53**	**$110.28**

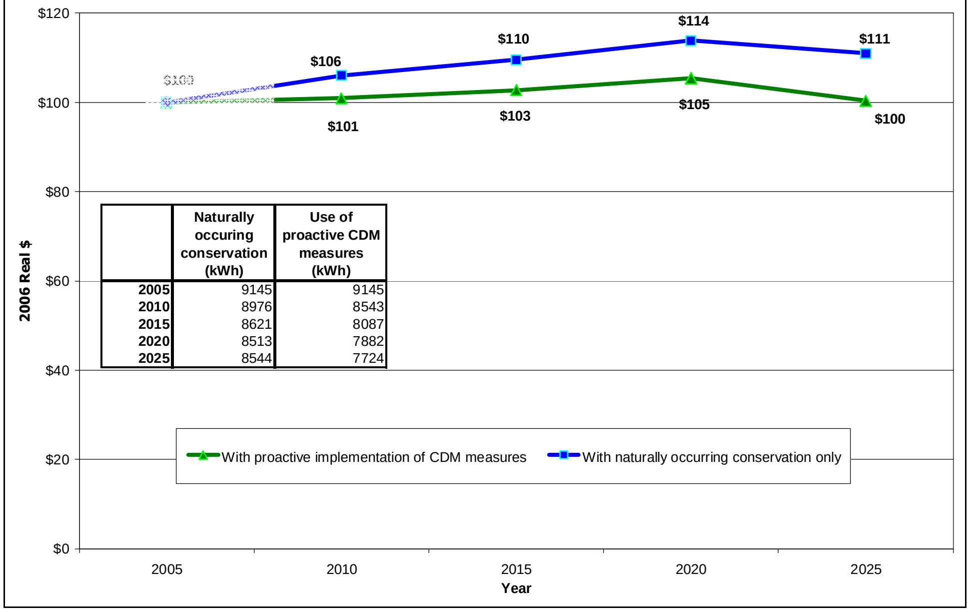
Source: OPA

Figure 3.27 – Changes on Household Electricity Bill – Lower Bound



Note: Costs are projected, based on assuming $100 current household bill amount in 2005.
Source: OPA

Figure 3.28 – Changes on Household Electricity Bill –Upper Bound



	Naturally occuring conservation (kWh)	Use of proactive CDM measures (kWh)
2005	9145	9145
2010	8976	8543
2015	8621	8087
2020	8513	7882
2025	8544	7724

Note: Costs are projected, based on assuming $100 current household bill amount in 2005.
Source: OPA

3.2.2 Avoided Cost and Value of Conservation

An economic assessment of conservation is a comparison of its costs and its benefits. The economic test we have used is called the Total Resource Cost (TRC) test. Its use is widespread. For example, it is standard practice in California, and in the OEB's direction to local distribution companies (LDCs) to evaluate CDM initiatives. The TRC test is also applied to CDM programs in the gas sector and to programs that switch fuels between gas and electricity.

The net costs and benefits of a CDM program are based on the total costs of the program, including both the participant costs and administrative costs. The benefits, or what are called the "avoided costs," include reduced generation, transmission and distribution capacity investments, reduced energy production costs and reduced transmission and distribution losses.[15]

Avoided costs have been used at two stages in the development of the IPSP. First, in the estimate of the economic potential of energy efficiency and fuel switching programs, and secondly, in the estimate of the value of the CDM initiative in aggregate. They will also be used, along with other measures, in the selection and design of specific CDM programs. Understanding how avoided costs are developed is central to the conservation initiative.

[15] There is an extended version of the test that includes societal costs, and in particular environmental damage costs. The OEB's guidance for the use of the TRC does not include such costs. In this respect, we follow the OEB's approach.

The following sections describe the methodology for calculating avoided costs, the current estimates for the components of avoided costs and for the avoided cost of the CDM initiative as a whole. Further details can be found in the CDM paper (#3), as revised.

Avoided Cost Methodology

We have used two approaches to calculating avoided costs:

- incremental costs of power and energy were determined by a marginal analysis; these can be added in appropriate proportions to evaluate any CDM program
- the CDM program as a whole was assessed by comparing complete system simulations with and without the entire CDM initiative over the plan period.

System simulations for the power system as a whole have been performed using the PROSYM model. These simulations are done at five-year intervals, with interpolated or extrapolated values for other years. The simulations determine the incremental cost of energy for the Preliminary Plan. The incremental cost of generation capacity is taken to be the carrying cost of a single cycle gas turbine plant. A discount rate of four percent (in real terms, i.e., net of general inflation) is used to annualize the capital costs. A sensitivity value of 11 percent is also used.

All values of avoided costs have been increased by 10 percent, reflecting the uncertainty in generation cost estimates. This difference is representative of the premium between median and most likely values found in the supply mix advice studies.

OPA Estimates of Avoided Costs

Incremental Costs of Energy and Capacity

Table 3.6 shows the incremental energy and generation capacity costs. The time periods are generally consistent with the OEB definitions, as shown in Table 3.6 and Table 3.7.

Table 3.6 – Seasonal Periods

Season	Months Included
Winter	December – March
Summer	June – September
Shoulder	April, May, October, November

Source: OPA

Table 3.7 – Peak versus Off-Peak Hours

	Winter	Summer	Shoulder
Peak	0700-1100 and 1700-2200 weekdays	1100-1700 weekdays	None
Mid-Peak	1100-1700 and 2000-2200 weekdays	700-1100 and 1700-2200 weekdays	0700-2200 weekdays
Off-Peak	0000-0700 and 2200-2400 weekdays; all hours weekends	0000-0700 and 2200-2400 weekdays;all hours weekends	0000-0700 and 2200-2400 weekdays; all hours weekends

Note: Numbers are the daily hours for the various periods. Source: OPA

Table 3.8 – Incremental Costs by Season and Time-of-Use Period

Year	Ontario Seasonal Average Avoided Energy Costs (CAD$2006/MWh)								Avoided Capacity Costs (CAD$2006/kW-yr)			
	Winter			Summer			Shoulder					
	On Peak	Mid-Peak	Off-Peak	On Peak	Mid-Peak	Off-Peak	Mid-Peak	Off Peak	Generation		Transmission	Distribution
Hours/ Period	602	688	1614	522	783	1623	1305	1623	n/a	n/a	n/a	n/a
									4% real	10% real	11% real	11% real
2008	46.9	37.0	30.7	68.4	53.0	33.1	37.1	28.9	83.9	118.9	5.4	0.0
2009	50.4	41.8	34.8	69.6	55.8	36.6	41.7	31.5	83.9	118.9	5.4	6.7
2010	53.9	46.5	38.9	70.8	58.6	40.1	46.3	34.2	83.9	118.9	5.4	6.7
2011	57.3	51.3	43.0	71.9	61.4	43.7	50.8	36.8	83.9	118.9	5.4	6.7
2012	60.8	56.0	47.1	73.1	64.1	47.2	55.4	39.5	83.9	118.9	5.4	6.7
2013	64.3	60.7	51.2	74.3	66.9	50.7	60.0	42.1	83.9	118.9	5.4	6.7
2014	67.7	65.5	55.3	75.4	69.7	54.3	64.6	44.8	83.9	118.9	5.4	6.7
2015	71.2	70.2	59.4	76.6	72.4	57.8	69.2	47.4	83.9	118.9	5.4	6.7
2016	71.4	70.2	60.2	76.4	72.6	58.6	69.6	49.1	83.9	118.9	5.4	6.7
2017	71.5	70.1	61.1	76.2	72.8	59.4	70.1	50.8	83.9	118.9	5.4	6.7
2018	71.7	70.1	61.9	76.0	73.0	60.2	70.6	52.6	83.9	118.9	5.4	6.7
2019	71.8	70.0	62.7	75.8	73.2	61.0	71.0	54.3	83.9	118.9	5.4	6.7
2020	72.0	69.9	63.6	75.6	73.4	61.8	71.5	56.0	83.9	118.9	5.4	6.7
2021	71.2	69.2	62.4	74.4	72.2	60.5	71.1	53.3	83.9	118.9	5.4	6.7
2022	70.5	68.5	61.3	73.1	71.0	59.3	70.7	50.7	83.9	118.9	5.4	6.7
2023	69.7	67.9	60.1	71.8	69.7	58.0	70.3	48.0	83.9	118.9	5.4	6.7
2024	69.0	67.2	59.0	70.5	68.5	56.8	70.0	45.4	83.9	118.9	5.4	6.7
2025	68.3	66.5	57.8	69.2	67.3	55.5	69.6	42.7	83.9	118.9	5.4	6.7
2026	67.5	65.8	56.7	67.9	66.1	54.3	69.2	40.1	83.9	118.9	5.4	6.7
2027	66.8	65.1	55.5	66.7	64.8	53.0	68.8	37.4	83.9	118.9	5.4	6.7

Source: OPA

Losses are calculated for delivery to the wholesale delivery points. We have used the loss estimates developed by Navigant Consulting for Hydro One Networks, as approved by the OEB[16]. Their results are shown in Table 3.9, below.

Table 3.9 – Transmission Losses by Season and Time-of-Use Period

	Winter			Summer			Shoulder	
	Peak	Mid-Peak	Off-Peak	Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak
Marginal Losses (%)	9.9	7.4	5.7	5.6	5.7	5.3	12.3	4.6

Source: Navigant

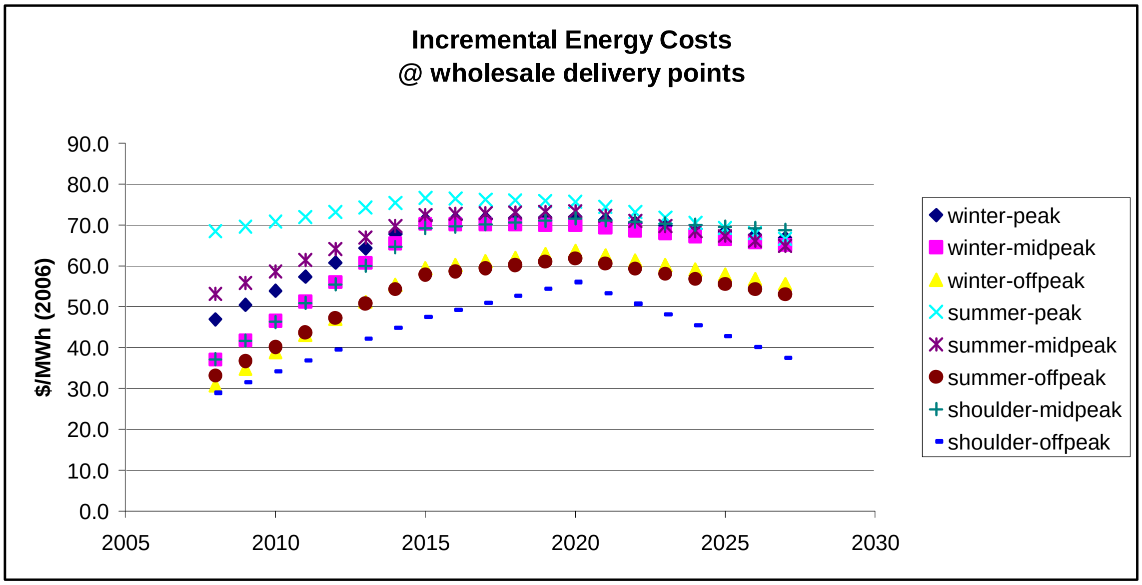
The energy costs are shown in the Table 3.8.

The avoided transmission and distribution costs are previously published estimates, which the OPA considers appropriate. The energy costs, including the cost of losses, are shown graphically in Figure 3.29.

It should be noted that the incremental energy costs are not forecasts of the Hourly Ontario Energy Price (HOEP). They are estimates of the incremental costs of meeting more demand as measured at the wholesale metering point and do not include, for example, the uplift items that are part of the HOEP.

[16] This document is available at http://www.oeb.gov.on.ca/documents/dcdm_hydro_acar_170605.pdf

Figure 3.29 – Incremental Energy Costs by Season and Time-of-Use Period



Source: OPA

Value Created by Conservation in the Preliminary Plan

The OPA has estimated the value of the total CDM initiative using a simulation approach and based on the peak demand and energy savings described previously.

For the analysis, CDM resources were removed from the Preliminary Plan, requiring extra generation resources to reliably meet the demand, as follows:

- a firm take or pay import of 2,000 MW starting in 2015 costing $4,500/kW
- simple cycle plant in the amounts of 600 MW in 2015, and an additional 900 MW in 2027, costing $675/kW
- two extra nuclear units coming in service in 2016 and 2027, respectively, costing $3,400/kW, including interest during construction
- advancing 500 MW of pumped storage from 2020 to 2016, and adding another 1,000 MW in 2016, each costing $1,500/kW
- additional reliance on the interconnections (imports) in the short term.

The resulting value of the CDM initiative over the 2008–27 period, using a four percent real discount rate, was found to be $10 billion, corresponding to an average of $80/MWh.

This estimate has been replicated closely using the incremental cost approach.

3.3 Preliminary Plan – Environmental Performance Perspective

As part of the integrated planning process, the OPA is conducting an analysis of the environmental performance of the IPSP using indicators and measures developed in the sustainability paper (#6). For the IPSP, the OPA is considering greenhouse gas emissions (GHGs), contaminant air emissions, radioactivity, water use, waste production and land use. The descriptions of these performance indicators in paper #6 are qualitative, and the methods by which they are measured and applied to the IPSP analysis are presented here and in Appendix E. In paper #6, land use is described under the criterion of societal acceptance.

Our proposed approach includes six basic steps that form a robust, flexible means of analyzing the IPSP's integrated elements according to environmental performance indicators. This work builds on that completed for the *Supply Mix Advice Report*, updated for the application to the IPSP, to account for the locations of IPSP generation and transmission elements. The steps are as follows:

- step one involves collecting raw environmental data for generation and transmission options, where this information is available or applicable for the particular option
- step two aggregates the data into indices according to general categories of environmental impacts, where appropriate (e.g., conventional contaminant air emissions and GHGs)
- step three applies modifiers to the aggregated data that account for site specificity of options and potential impacts
- step four applies the data (raw and/or modified) to the supply and transmission resources developed for the IPSP. The results of this step depend on the electricity generated by each resource, the installed capacity (in the case of land use) and by the estimated transmission infrastructure requirements of the plan
- step five generates the results to describe the environmental performance of the IPSP according to the environmental categories. The results of the IPSP are then applied to baseline figures (e.g., the current system mix) to determine the plan's environmental performance
- step six involves subsequent iterations of the plan and, in the future, subsequent IPSPs, to measure and track performance resulting from variations in types and locations resources or to changes in the overall system performance over time (e.g., changes in energy output of specific resources).

We have retained SENES Consultants Limited to complete the preliminary analysis for the Preliminary Plan. SENES has recently updated the environmental emissions data from their 2005 report for the supply mix advice, developed modifiers to account for site and technology specificity, and developed the preliminary framework for the analysis. The application of this methodology to the Plan is ongoing, but a set of preliminary results is presented in this section.

This framework is intended to be flexible and robust. It can evaluate different resource mixes or different indicators. It can also test the sensitivity of the results to changes in assumptions and input data. Using information for the total energy generated by the system, the analysis can express emissions on a unit basis (e.g., per GWh of energy produced) and in absolute terms (e.g., in total tonnes per year). On an absolute basis, land use is a total area, not expressed per year, that is claimed at one time during the course of the Plan.

At this stage in the analysis, the modifiers have not been applied to the results to account for site and technology specific information. These modifiers will be applied as the IPSP develops, but they are described in Appendix E for the purpose of stakeholder discussion.

The results of the preliminary analysis are displayed in the following tables. Table 3.10 shows the preliminary results comparing the per GWh environmental performance of the 2010 resource mix to the performance predicted in the Preliminary Plan for 2025. The per unit results are derived by dividing the absolute result for each category by the total amount of energy produced by the supply mix. The total energy generated by each supply resource is estimated using the PROSYM simulation described in Appendix B. The usefulness of displaying the results on a per unit basis is that the percent change, either up or down, can be clearly displayed.

Table 3.10 – Preliminary Results of Environmental Performance – Unit Basis

Year	Air												Water		Land	
	Conv. Normalized	NO_x	SO_2	$PM_{2.5}$	Mercury	Formal-dehyde	Benzene	GHG Normalized	CO_2	Methane	N_2O	Radio-activity	With-drawal	Cons-umption	Waste	Land Use
	(wt kg/GWh)	(kg/GWh)	(kg/GWh)	(kg/GWh)	(kg/GWh)	(kg/GWh)	(kg/GWh)	(wt T/GWh)	(T/GWh)	(T/GWh)	(T/GWh)	(person SV/ MWh)	(MM m^3/GWh)	(MM m^3/GWh)	(kg/GWh)	(ha/GWh)
2010	405	173	76	8.61	0.001	0.22	0.005	115	106	5.4	0.85	0.0001	5,173	0.79	2,613	1,340
2025	321	171	29	9.98	0	0.24	0	55	45	6.5	1.03	0.0001	5,148	0.82	37	1,827
% Change	-21%	-1%	-61%	16%	-100%	10%	-100%	-52%	-58%	20%	20%	-2%	-0.5%	3%	-99%	36%

Note: "wt" refers to the weighted indices for conventional contaminants and GHG emissions (see Appendix E for more information).
Source: OPA, SENES

Table 3.11 and Table 3.12 summarize the absolute environmental performance of each resource included in the Preliminary Plan at 2010, and Table 3.13 and Table 3.14 summarize the same information at 2025. This part of the analysis provides the absolute environmental performance results in terms of a total quantity or amount per year.

Table 3.11 – Preliminary Results of Environmental Performance at 2010 (1 of 2)

Resources (2010)	Energy Output	Air						
		Conv. Normalized	NO_x	SO_2	$PM_{2.5}$	Mercury	Formal-dehyde	Benzene
	MWh/yr	wt T/yr	T/yr	T/yr	T/yr	kg/yr	T/yr	T/yr
Gas	20,924,000	12,639	5,249	180	249	0	38	0
Coal	15,024,000	27,784	6,054	10,503	142	240	4	1
Coal Gasification	0	0	0	0	0	0	0	0
Biomass	1,424,000	808	318	105	32	0	0	0
Nuclear (new and refurb)	90,755,000	29,596	18,876	1,002	953	0	0	0
Hydroelectric - Peaking	31,707,913	2,354	906	1,294	81	0	0	0
Hydroelectric - Baseload	18,372,366	1,364	525	750	47	0	0	0
Wind	4,127,000	638	173	246	91	0	0	0
Photovoltaic	0	0	0	0	0	0	0	0
Import (Hydroelectric)	4,290,000	318	123	175	11	0	0	0
Pumped Storage	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0
CDM	0	0	0	0	0	0	0	0
Total (Absolute)	**186,624,279**	**75,500**	**32,223**	**14,255**	**1,607**	**240**	**41**	**1**

Note: Zeros indicate that no value is available rather than there is no impact.
Source: OPA, SENES

Table 3.12 – Preliminary Results of Environmental Performance at 2010 (2 of 2)

Resources (2010)	Energy Output		Air					Water		Land	
			GHG Normal-ized	CO_2	Methane	N_2O	Radiation	Withdrawal	Cons-umption	Land Use	Waste
	MWh/yr	Gwa/yr	wt kT/yr	kT/yr	kT/yr	kT/yr	person SV/yr	MM m^3/yr	MM m^3/yr	ha	kT/yr
Gas	20,924,000	2.39	5,879	5,826	1,004	159	0.07	1,590	8	234	0
Coal	15,024,000	1.71	12,999	12,950	0	0	0.9	0	0	4,311	480.77
Coal Gasification	0	0	0	0	0	0	0	0	0	0	0
Biomass	1,424,000	0.16	132	132	0	0	0	3	3	424	0.02
Nuclear (new and refurb)	90,755,000	10.35	898	898	0	0	25.1	20,692	138	1,717	6.81
Hydroelectric - Peaking	31,707,913	0	1,036	0	0	0	0	571,591	0	129,839	0
Hydroelectric - Baseload	18,372,366	0	361	0	0	0	0	320,445	0	2,837	0
Wind	4,127,000	0.47	49	0	0	0	0	0	0	53,664	0
Photovoltaic	0	0	0	0	0	0	0	0	0	0	0
Import (Hydroelectric)	4,290,000	0.49	140	0	0	0	0	51,090	0	57,000	0
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0	0
CDM	0	0	0	0	0	0	0	0	0	0	0
Total (Absolute)	**186,624,279**	**15.58**	**21,493**	**19,807**	**1,004**	**159**	**26**	**965,410**	**148**	**250,025**	**488**

Note: Zeros indicate that no value is available rather than there is no impact.
Source: OPA, SENES

Table 3.13 – Preliminary Results of Environmental Performance at 2025 (1 of 2)

Resources (2025)	Energy Output	Air						
		Conv. Normalized	NO_x	SO_2	$PM_{2.5}$	Mercury	Formal-dehyde	Benzene
	(MWh/yr)	wt T/yr	T/yr	T/yr	T/yr	kg/yr	T/yr	T/yr
Gas	27,150,000	17,176	7,133	245	339	0	51	0
Coal	0	0	0	0	0	0	0	0
Coal Gasification	1,799,000	2,893	890	1,102	0	0	0	0
Biomass	2,858,000	1,622	637	211	64	0	0	0
Nuclear (new and refurb)	103,084,000	39,389	25,122	1,333	1,269	0	0	0
Hydroelectric - Peaking	31,707,913	2,354	906	1,294	81	0	0	0
Hydroelectric - Baseload	18,372,366	1,364	525	750	47	0	0	0
Wind	12,117,000	1,872	509	721	267	0	0	0
Photovoltaic	31,000	16	4	3	1	0	0	0
Import (Hydroelectric)	7,200,000	534	206	294	18	0	0	0
Pumped Storage	6,262,930	465	179	256	16	0	0	0
Transmission	0	0	0	0	0	0	0	0
CDM	0	0	0	0	0	0	0	0
Total (Absolute)	**210,582,209**	**67,685**	**36,110**	**6,210**	**2,102**	**0**	**51**	**0**

Note: Zeros indicate that no value is available rather than there is no impact.
Source: OPA, SENES

Table 3.14 – Preliminary Results of Environmental Performance at 2025 (2 of 2)

Resources (2025)	Energy Output		Air					Water		Land	
			GHG Normalized	CO_2	Methane	N_2O	Radiation	Withdrawal	Cons-umption	Land Use	Waste
	MWh/yr	Gwa/yr	wt kT/yr	kT/yr	kT/yr	kT/yr	person SV/yr	MM m^3/yr	MM m^3/yr	ha	kT/yr
Gas	27,150,000	3.1	7,990	7,918	1,364	216	0.09	2,063	10	359	0
Coal	0	0	0	0	0	0	0	0	0	0	0
Coal Gasification	1,799,000	0.21	136	0	0	0	0.1	0	0	168	0
Biomass	2,858,000	0.33	266	266	0	0	0	7	5	1,092	0.03
Nuclear (new and refurb)	103,084,000	11.76	1,195	1,195	0	0	28.5	23,503	157	1,956	7.73
Hydroelectric - Peaking	31,707,913	0	1,036	0	0	0	0	571,591	0	129,839	0
Hydroelectric - Baseload	18,372,366	0	361	0	0	0	0	320,445	0	2,837	0
Wind	12,117,000	1.38	143	0	0	0	0	0	0	148,448	0
Photovoltaic	31,000	0	4	0	0	0	0	0	0	0	0
Import (Hydroelectric)	7,200,000	0.82	235	0	0	0	0	85,745	0	57,000	0
Pumped Storage	6,262,930	0.71	205	0	0	0	0	80,738	0	30,274	0
Transmission	0	0	0	0	0	0	0	0	0	12,747	0
CDM	0	0	0	0	0	0	0	0	0	0	0
Total (Absolute)	**210,582,209**	**18.31**	**11,569**	**9,379**	**1,364**	**216**	**28.7**	**1,084,091**	**172**	**384,719**	**8**

Note: Zeros indicate that no value is available rather than there is no impact.
Source: OPA, SENES

A number of insights can be drawn from the preliminary environmental analysis:

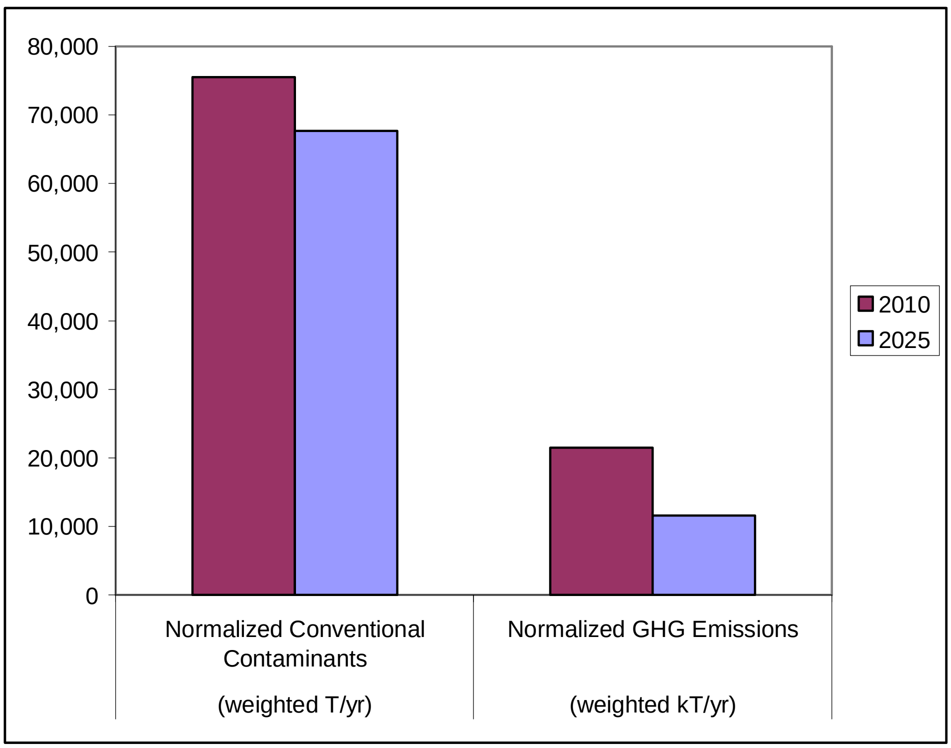
- overall capacity expansion to meet future demand growth will be a challenge to improving the environmental performance in all of the categories
- changes in the overall supply mix, such as increased natural gas, wind, biomass, and the elimination of conventional coal-fired generation will present opportunities for mitigating or managing environmental effects
- the phasing out of coal results in improvements in SO_2, conventional contaminant and GHG emissions, both on an absolute and per unit basis
- NO_x and $PM_{2.5}$ emissions increase on an absolute basis, but remain steady or decrease when compared per GWh

- radioactive air emissions increase slightly on an absolute basis, but decrease slightly when quantified per person
- water consumption and withdrawal increase on an absolute basis, but per GWh, water consumption and water withdrawal remain steady
- land use increases both on an absolute and per unit basis, which at this stage of the analysis, appears to be attributed primarily to the development of renewable resources and the building of transmission lines.

The environmental performances in several categories between the systems at 2010 and 2025 are illustrated in the following figures. Figure 3.30 shows that the weighted indices for conventional contaminant air emissions and GHGs decrease in absolute terms. Figure 3.31 shows that wastes decrease significantly, radioactivity remains about the same and water consumption increases between 2010 and 2025, while Figure 3.32 shows that land use and water withdrawal increase.

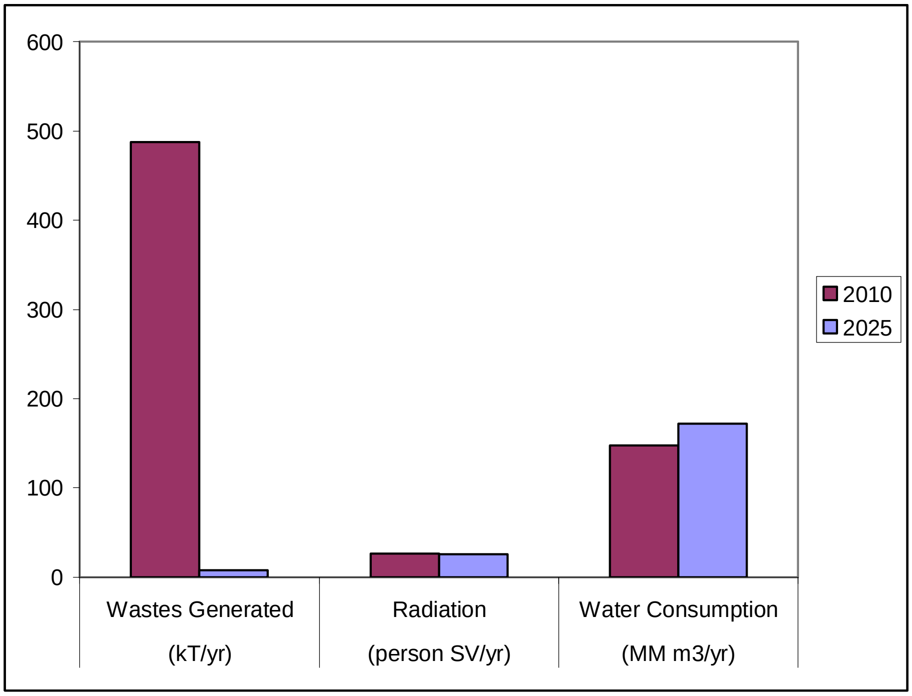
These insights are useful, even at this preliminary stage, because they will assist the OPA, with guidance and advice from stakeholders, in identifying and prioritizing mitigation strategies that will achieve progress toward sustainability.

Figure 3.30 – Absolute Air Emissions Rates at 2010 and 2025



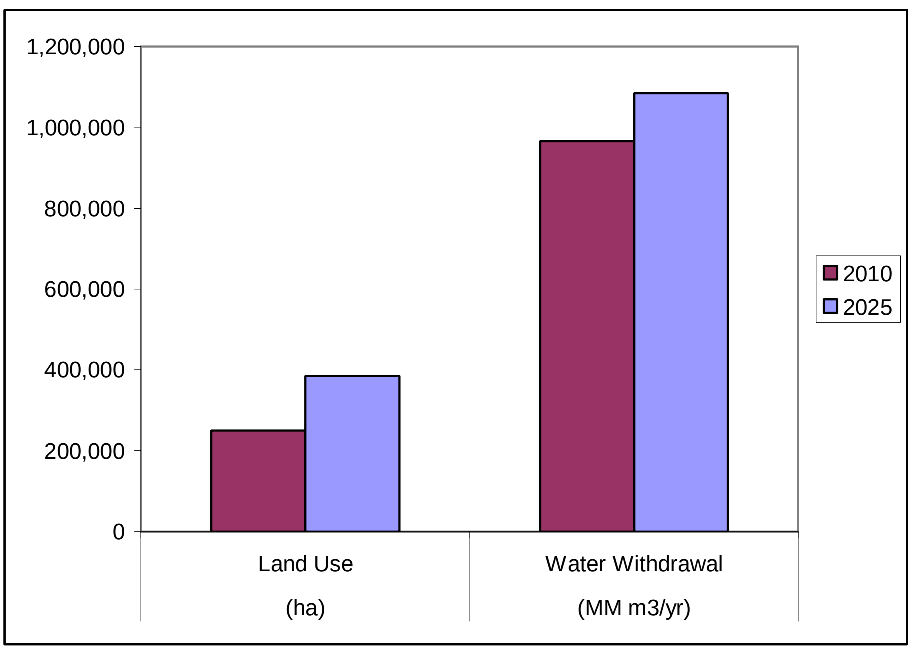
Source: OPA

Figure 3.31 – Absolute Values for Wastes, Radioactivity and Water Consumption at 2010 and 2025



Source: OPA

Figure 3.32 – Absolute Values for Land Use and Water Withdrawal at 2010 and 2025



Source: OPA

3.4 Preliminary Plan – Flexibility Perspective

A key aspect of the Preliminary Plan is its ability to adapt changing circumstances in the next several years as new information becomes available. As was discussed in section 3.1, the Preliminary Plan seeks to establish and maintain a portfolio of options to address future opportunities, risks and change in general. This portfolio can be drawn upon in the event of adverse circumstances, such as higher than anticipated load growth, or planned resources that fail to materialize or are delayed. In order for such a portfolio to be available when needed, near-term actions are required, such as seeking approvals and conducting preliminary development work for the projects. These actions are described in section 4, and are an essential part of the Preliminary Plan.

This section takes this approach further, by assuming such adverse circumstances and identifying whether mitigating actions will be available.

As discussed, the coal-replacement plan manages risks to reliable supply until the year 2014. This section goes beyond this time period to consider risks having implications for the post-2014 period of the plan.

The scenarios indicated in Table 3.15 consist of changes to assumptions that potentially have such long-term impacts. The table shows the impact of the change itself, together with the responses that could be taken to mitigate these impacts.

Table 3.15 – Adaptability of the Preliminary Plan: Scenario Analysis

Scenario	Impact	Potential Mitigating Options
A decision is made to not refurbish Pickering B	Capacity is reduced by 2,000 MW between 2015 and 2020	Acquire 1,000 MW of renewable capacity purchases by 2017, increasing to 2,000 MW by 2020 Acquire a combination of renewable capacity purchase by 2017 and additional new nuclear capacity between 2018 & 2020 Acquire a combination of new natural gas generation renewable capacity purchases by 2017 and additional new nuclear capacity by 2020 Use emerging technologies and CDM to a greater extent
The in-service date of new nuclear is delayed (e.g., New nuclear is not available until 2020 & 2021 rather than in 2018 & 2019)	A delay in cumulative capacity additions of 700 MW in 2018, 1,400 MW by 2019	Acquire up to 1,400 MW of short-term renewable capacity purchase by 2019 Acquire a combination of new natural gas generation, and short-term renewable energy capacity purchases Use emerging technologies and CDM to a greater extent
Moose River Basin hydroelectric potential is not developed	A reduction of 500 MW of effective capacity by 2020, 680 MW by 2025 (940 MW total installed by 2025)	Acquire 500 MW renewable capacity purchase by 2020, then 440 MW additional renewable generation or capacity purchase by 2025 Acquire additional new nuclear generation between 2019 and 2025 Acquire a combination of new natural gas generation and renewable generation or capacity purchase Use emerging technologies and CDM to a greater extent
Greater success in capturing CDM potential	Up to several thousand MW	Defer new planned resources Reduce requirement for new planned resources Potential for CDM to make greater contribution to risk management (e.g., in-service and performance risk) If in the near-term, potential to advance shut-down of coal capacity required for near-term risk management
Renewable purchase from outside of the province	An additional 1,000 MW to 2,000 MW of firm hydroelectric imports	Defer new planned resources Reduce requirement for new planned resources Potential for hydroelectric imports to contribute to risk management If in the near-term, potential to advance shut-down of coal capacity required for near-term risk management

Source: OPA

Table 3.15 illustrates a number of potential options for addressing longer-term uncertainties. These options include acquiring shorter lead-time resources, such as natural gas-fired generation, and acquiring longer lead-time resources, such as new nuclear generation and firm imports from outside Ontario. The preservation of longer lead-time options requires work to be initiated in the near term (e.g., project scoping, technology selection, siting, approvals and negotiations). An important example is new nuclear, where lead times can be between 10 and 12 years. Similarly, renewable energy imports may require lead times between four and 10 years, depending on the degree of resource development and transmission enhancement required. In contrast, shorter lead time options, such as natural gas generation, may require lead-times between three and five years.

Options also include the potential for greater use of emerging technologies, as well as the potential for greater success in capturing CDM.

The options identified can help to compensate for losses or delays in expected resources, or to defer or reduce the need for additional resources, as well as to help manage risk throughout the planning horizon.

3.5 Preliminary Plan – Societal Acceptance Perspective

The formulation of the Preliminary Plan is guided by the development and evaluation criteria established in the sustainability paper (#6). Within this framework, societal acceptance of the plan itself and its constituent elements are a key consideration. Societal acceptance includes engaging stakeholders in an open transparent process, encouraging a conservation culture, supporting regional development and livelihood sufficiency within communities throughout the province, considering public health and safety impacts associated with capacity and transmission expansion projects and minimizing land use impacts, but where some impacts are unavoidable, altering land use in an acceptable manner.

The Preliminary Plan is responsive to government policy. Towards this end, the plan, for example, seeks to increase the use of generation from renewable sources and build transmission capacity to enable the utilization of these sources in load centres. The expansion of renewable energy and transmission lines may disproportionately impact particular communities, but the benefits, such as cleaner air, will flow to all Ontarians.

There are also issues related to the social acceptability of conventional supply options. For instance, some residents oppose the siting of generating units in their communities, while other communities have voiced their support for the continued operation, and for the expansion or installation of new generation.

Land use impacts of proposed capacity and transmission expansion projects are being measured as part of the evaluation of societal acceptance for the Preliminary Plan. (See Appendix E for a description of the methodology used). Various modifiers are included within this framework for evaluating land use in order to consider societal acceptance. The assessment addresses potential impacts on, for instance, First Nations, ecologically sensitive areas and impacts on both urban and rural communities. It also considers the permanence of potential land use and cumulative effects.

The societal acceptance criterion puts added significance on the stakeholder consultation process. As the consultation process is currently ongoing, the OPA will continue to address stakeholder concerns.

4. Implementing the Plan

There is one overriding theme on the implementation of the Preliminary Plan. For the plan to be feasible, many actions are required now and in the near term to support not only the immediate and near-term needs, but also the options required in the medium term and opportunities that need to be available in the long term. Thereafter, these actions need to be supported on an ongoing basis.

In its planning, the OPA has been careful to ensure that the various plan elements and resources are viable and that their expected implementation and contribution to the plan is realized. These actions relate, for example, to implementation of CDM, renewable resources, coal replacement, nuclear refurbishment and transmission enhancements. Implementation of the plan will follow its filing with the Ontario Energy Board (OEB) in 2007.

For stakeholders to see the required actions in their proper perspective, the near-term actions are grouped into three categories: actions for implementation in the near term (2007-2010), actions to develop options for medium term (2011-2015) and actions to create opportunities for the long term (2016-2027). This grouping should be viewed as approximate, given that it is not possible to isolate the nature and time period of impact of all actions.

In this paper, we use the term "actions" to capture a variety of tasks and activities, including the initiation of regulatory approvals, initiation of studies, commitment by a proponent to a project or preferred approach, pre-engineering work on a project, and the actual project development. Additionally, some of the identified actions may be taken before the plan is finalized.

4.1 Actions for Implementation in the Near Term

This category includes actions related to the resources to be implemented in the near term (2007-2010). Successful completion of these actions will ensure that the near-term plan elements and resources are implemented as planned.[17]

The full set of actions assigned to this category is summarized in Table 4.1 and Table 4.3 for CDM and supply resources and for transmission, respectively. For the transmission projects, the project numbers in the first column are shown in the maps in Figure 4.1.

[17] In the near-term category, we mean those near-term actions that result in a commitment to a particular course of resorts development, for example a decision to commit to a particular solution for a local-area supply problem, or committing a particular generation or transmission project. Such commitment is not absolute, i.e., it will still be possible not to proceed with the project, but this would not be an expected outcome, and considerable cost may be involved in doing so. There may also be a regulatory requirement to proceed with the project.

Table 4.1 – Actions on CDM and Supply Decisions in the Near-Term (2007-2010)

Resource Type	Reasons	Action
CDM		
CDM	Increased CDM	Achieve the following targets: conservation, 77 MW; energy efficiency, 874 MW; time-of-use pricing, 178 MW; demand response, 212 MW; fuel switching, 89 MW; and self generation, 112 MW. Develop additional 1,500 MW of CDM by 2010
		Conduct detailed evaluation, measurement and verification to confirm CDM savings or reductions achieved
Renewables		
Wind	Increased generation	Facilitate development of wind resources in: northwestern Ontario, northern and eastern shores of Lake Superior, north of Georgian Bay, eastern shore of Georgian Bay, Bruce Peninsula to Goderich, Goderich to London, northern shore of Lake Erie, northern shore of Lake Ontario, Lake Simcoe to Lake Nipissing.
		Cooperate with IESO in ongoing assessment of system operability requirements associated with increasing penetrations of wind generation, and analyze operating data and improve forecasting methods
Hydroelectric		Encourage OPG and other hydroelectric proponents to continue with projects and plans for developing near-term and long-term hydroelectric potential, including projects listed in Table 4.2
		Monitor hydroelectric developments on an on-going basis and assess their impacts on the IPSP
		Evaluate potential environmental impacts of new hydroelectric projects according to the following factors: socio-economic (land use, First Nations, settlement features); agricultural (soils); aquatic (wetlands, lakes, rivers); terrestrial (habitat); and forestry (forests and woodlots)
		Pursue opportunities for hydroelectric purchases from outside of Ontario
Biomass		Initiate work on converting Atikokan generating station to biomass
Renewables General		Develop at least 1,200 MW of new renewables to meet 2010 target
Coal		
Nanticoke, Lambton, Atikokan, Thunder Bay	Coal replacement plan	Retain all existing coal capacity to 2010. Start reducing in 2011 and eliminate by end of 2014 while seeking opportunities to advance phase-out; decide whether and what types of pollution control equipment is to be installed on coal units; retain flexibility to adjust replacement strategy as necessary based on risk and new information; and consider options for future use of the coal-fired generation sites
Nuclear		
Nuclear	Increased generation	Bruce Power to keep OPA informed of status of developments on Bruce 1 and 2 restart and on Bruce A refurbishment program
		Bruce Power to assess Bruce B refurbishment viability
		OPG to complete Pickering B refurbishment viability assessment by 2008. Keep OPA informed of on-going developments including decisions whether to proceed/not proceed with refurbishment
Natural Gas		
Smart Gas Strategy	Increased generation, transmission relief	Promote the use of natural gas in high efficiency and high value applications, inlcuding combined heat and power, peaking power and local area reliability
		Assess and define solutions for generation required for local area supply/transmission relief (e.g., York Region, Kitchener-Waterloo-Cambridge-Guelph, GTA southwest)

Source: OPA

The hydroelectric projects requiring near-term actions are shown in Table 4.2, which is taken from the supply resources discussion paper.

With respect to nuclear actions, options to develop new nuclear units are being considered for existing licensed nuclear sites. The environmental assessment and safety regulatory processes are well established, providing guidance to the proponents and improving their ability to meet schedule and cost constraints. The following points relate to near-term actions:

- Bruce Power and OPG have applied for site preparation licences for new nuclear plants at the Bruce and Darlington sites, respectively. The process of obtaining all of the necessary approvals for new nuclear units is lengthy. The many approvals required fall mainly under the jurisdiction of the Canadian Nuclear Safety Commission (CNSC).

- The environmental assessment process, combined with construction and commissioning lead times for the first unit, result in project lead times that can range from nine to 12 years; this means that there is a need to make decisions about new nuclear in a timely manner if the option of utilizing new nuclear to meet the expected supply gap is to be preserved
- In the IPSP, the OPA will recommend that environmental assessments, licensing activities and feasibility studies of new nuclear units be pursued in order to keep this option available for meeting the supply gap in the 2015 to 2025 time period.

Table 4.2 – Hydroelectric Projects Involving Near-Term Actions

River	Station(s)	Capacity (MW)	Energy (GWh)	Projected In-Service
Southern Ontario				
Muskoka	North Bala	4	21	2012
Niagara	Sir Adam Beck No.1	36	170	2008-2014
	Niagara Tunnel	0	1,600	2009
Trent	Trent University	6	34	2009
	Healey Falls, Ranney Falls	12	45	2009-2010
Welland	DeCew Falls- NF23	18	44	2014-15
	Schikluna, Gibson	12	72	2009-2011
Eastern Ontario				
Madawaska	Mountain Chute	8	8	2011-2012
Ottawa	Chaudiere	7	26	2011
	Otto Holden	4	11	2012-2015
Rideau	Rideau Falls	2	7	2008
South Nation	Casselman	1	4	2012
Northeastern Ontario				
Abitibi	Abitibi Canyon	20	10	2006-2007
	Otter Rapids	10	25	2012-2013
Kapuskasing	Big Beaver Falls	11	58	2012
Mattagami	Little Long, Harmon, Kipling, Smoky Falls	450	826	2011
	Yellow/Island Falls	18	95	2013
	Lower Sturgeon, Sandy Falls, Wawaitin	16	69	2009
	Mattagami Lake Dam	5	24	2010
Montreal	Ragged Chute	4	14	2006
	Hound Chute	6	23	2009
Spanish	Espanola	16	116	2006
Northwestern Ontario				
Aguasabon	Mileage 19.2/25.6	10	53	2012
	Long Lake Dam	7	34	2011
English	Lac Seul	13	51	2007-2008
Nipigon	Cameron Falls, Alexander, Pine Portage	9	37	2007-2011
White River	Umbata Falls	23	81	2008

Source: OPA

Table 4.3 – Actions on Transmission Decisions for the Near Term (2007-2010)

Project #	Project Name	Reasons For Transmission Facilities	Facilities Description	Work Type	Completion Date	Estimated cost ($M)
	Bulk Transmission					
1	Bruce-GTA Transmission Reinforcement	Increased Generation	SVC and shunt capacitors in Southwestern Ontario	Facilities	2009	80
			Upgrade 230 kV circuits from Hanover TS to Orangeville TS	Facilities	2009	10
			Upgrade Bruce area generation rejection facilities	Facilities	2009	10
			Series capacitors on Bruce GS to Longwood TS and Longwood TS to Middleport TS 500 kV circuits	Class EA and Facilities	2010	100
			180 km 500 kV double-circuit line from Bruce to GTA	Ind. EA and Facilities	2011	600
2	GTA East 500kV Reinforcement	Reliability	Full switching of Claireville TS x Cherrywood TS 500 kV circuits	Facilities	2009	60
3	North-South Transmission Reinforcement	Increased Generation	Series capacitors on Essa TS x Hanmer TS 500 kV circuits	Facilities	2010	50
4	Mattagami expansion and Northeast Generation Development	Increased Generation	SVCs at Porcupine TS and Kirkland Lake TS, and shunt capacitors north of Sudbury	Facilities	2010	60
5	Prince Wind and Sault Area Generation Development	Increased Generation	SVC at Mississagi TS and shunt capacitors in Algoma area	Facilities	2010	30
6	Atikokan Off-Coal	Maintain Transfer Capability	Shunt capacitors at Dryden TS and Fort Frances TS	Facilities	2010	7
7	Thunder Bay Off-Coal	Maintain Transfer Capability	Replacement of synchronous condenser with SVC at Lakehead TS	Facilities	2009	15
			Shunt capacitors and combining of buses at Thunder Bay GS	Facilities	2010	5
10	Hydro Quebec Interconnection	Increased Inter-tie Capability	230 kV double-circuit lines from Hawthorne TS to Ottawa and station upgrade at Hawthorne TS	Facilities	2010	130
	Local Area Reliability					
15	Southern Georgian Bay	Area load growth	Rebuild the 115 kV single-circuit line from Essa TS to Stayner TS to 230 kV double-circuit line; upgrade Stayner TS to 230 kV	Facilities	2009	92
16	GTA West	Area load growth	230 kV switching facilities at new Hurontario station	Facilities	2009	42
			230 kV cables from Hurontario SS to J. Yarrow TS	Facilities	2011	30
17	Windsor-Essex	Area load growth	Upgrade 115 kV circuits J3E/J4E	Facilities	2009	20
			Upgrade 115 kV circuits K2Z/K6Z	Facilities	2009	30
			New 230/115 kV autos at Kingsville Junction	Facilities	2012	50
18	Woodstock	Area load growth	13 km 230 kV double-circuit line; new 230 kV station in Woodstock with two 230/115 kV autos	Facilities	2009	65
19	Brant	Area load growth	115 kV double-circuit line and one 230/115 kV auto	Facilities	2009	50
20	Kitchener-Waterloo-Cambridge-Guelph (KWCG)	Area load growth	Low voltage shunt capacitors at Hanlon and Preston	Facilities	2009	5
			Connection of Preston auto to both D7G and D9G	Facilities	2009	3
			230/115 kV autos, one at Campbell TS and one at Preston TS	Facilities	2012	32
21	GTA	Area load growth	New 115 kV line/cables from Leaside TS x Birch Junction	Facilities	2010	25

Source: OPA

4.2 Actions to Develop Options for Medium Term

This category includes actions related to the resources required for implementation in the medium-term (2011-2015), including the development of potential resource options, that need to be taken now.[18]

[18] In the medium-term category we mean those near-term actions that result in an important milestone towards commitment of a demand, supply or transmission resource. It would be possible not to proceed with the project, and this could be done with a moderate penalty. An example would be an environmental assessment approval, which does not commit the applicant to proceed with the associated project.

The full set of near-term actions assigned to this category is summarized in Table 4.4 and Table 4.6 for CDM and supply resources and for transmission, respectively. For the transmission projects, the project numbers in the first column are shown in the maps in Figure 4.1.

Table 4.4 – Actions on Options for CDM and Supply in Medium Term (2011-2015)

Resource Type	Reasons	Action
CDM		
CDM	Increased CDM	Develop additional 1,000 MW by 2015
		Implement CDM programs in residential, commercial and industrial sectors
		Enhance culture of conservation and CDM delivery capability
		Carry out detailed evaluation measurement and verification to confirm CDM savings or reductions achieved
Renewables		
Hydroelectric	Increased generation	Encourage development of projects listed in Table 4.5
		Cooperate with various government ministries (MOE, MNR, MNDM), First Nations, and other hydroelectric proponents in rationalizing processes and policies to facilitate the development of the hydroelectric potential, in particular the undeveloped potential in northern Ontario such as along the Albany river.
		MNR to assess and possibly streamline process for release of undeveloped hydroelectric sites
		Monitor hydroelectric developments on an on-going basis and assess their impacts on the IPSP
		Pursue opportunities for hydroelectric purchases from outside of Ontario
Biomass		Encourage Ontario municipalities to assess feasibility of additional energy from landfill gas capture, wastewater treatment, and anaerobic digestion, including potential to combine additional municipal organic waste in the wastewater treatment process, and potential for co-firing of residual wastewater biosolids
		Encourage Ministry of the Environment to consider a number of possible adjustments to regulations to facilitate smaller biomass generators, particularly regarding disposal of ash and other small volume wastes. It also needs to consider changes that would facilitate the use of food waste in biodigesters.
		Encourage MNR, NRCan, and others to assess pyrolysis and other processes for converting biomass to biofuels, and other bioliquids that can facilitate efficient transportation.
		Encourage work on new protection and design systems for distributed remote generation
Local Area Supply		
Smart Gas Strategy	Increased generation, transmission relief	Initiate process for development of local area generation for in-service 2011-2012
Coal		
Nanticoke, Lambton, Atikokan, Thunder Bay	Coal replacement	Monitor with the IESO system risk profiles on an on-going basis. Inform OPG of any necessary adjustments to the coal replacement plan.
Nuclear Refurbishment		
Nuclear	Increased generation	Assess system and IPSP impacts of refurbishment programs on an on-going basis including future unit refurbishment outage schedules
		OPG to assess Darlington refurbishment feasibility
New Nuclear		
Nuclear	Increased generation	OPG and Bruce Power to continue with environmental assessments seeking approval for new nuclear generation at the Darlington and Bruce sites, respectively, and to keep OPA informed of on-going developments
		OPG and Bruce Power to continue with feasibility studies for new nuclear generation (including consideration of alternative nuclear technologies) at the Darlington and Bruce sites, respectively
		Monitor developments on an on-going basis and assess their impacts on the IPSP

Source: OPA

Table 4.5 – Hydro Projects Involving Actions for Medium and Long-Term Options

River	Site/Station	Capacity (MW)	Energy (GWh)	Possible In-Service
Eastern Ontario				
Madawaska	Bark Lake Dam	4	21	2015
Magnetawan	Bying Inlet	4	23	2015
	Lower Burnt Chute	3	16	2014
Northeastern Ontario				
Abitibi	Allan Rapids, Black Smith Rapids, Nine Mile Rapids, Sand Rapids, Sextent Rapids	711	1,894	2019-2023
Albany	Hat Island, Chard *	860	2,600	2020-2022
Amable du Fond	Gravelle Chute	3		2011
Englehart River	Larder	7	37	2012
Frederickhouse	Frederick House Lake Dam	4	21	2015
	Neelands Rapids (Twp. Fournier), Wanatango Falls, (Twp. Mann), Rapids (Twp. S. Clute and Leitch)	15	40	2019-2020
Grassy River	Timmins South	4	21	2012
Groundhog River	Wakusini (2 sites)	3	14	2020
Mattagami	Grand Rapids	174	457	2016
	Poplar	7	17	2021
Montreal	Lady Evelyn Lake Dam, Mistinikon Lake Dam	6	28	2011
Moose River	Renison	135	355	2021
Opasatika	Opasatika Rapids, Breakneck Falls, Christopher Rapids, Mariva Falls	19	34	2017-2018
Pic River	Manitou Falls	58	254	2015
Serpent	McCarthy Chute	2		2018
Sturgeon	Red Cedar Lake Dam	2	10	2015
Wanapitei	Wanapitei Lake Dam	2	8	2011
	Km 4.8- McVittie S	2	6	2014
Whitefish	below Cross Lake, Lang Lake (La Cloche Mts.)	6	24	2020
Northwestern Ontario				
Aguasabon	Lower Lake	10	61	2015
Black Sturgeon	At Hwy 17	3	15	2011
Current River	Throwbridge Falls, N. Thunder Bay, Bentley Creek	4	23	2012
Kaministiquia	Hume, Lot 2 Block 'A' (Twp. Paipoonge), Mokoman Falls, Shabaqua Corners	24	64	2013
Little Jackfish	Mileage 7.9	132	570	2014-2015
Namakan	Myrtle Falls, Hay Rapids/High Falls	18	63	2014-2015
Namewaminikan	Km 8 & km 12.8 (combined) Dragonfly Lake, High Falls	24	85	2015-2016
White	1.6 km below Chicagonce Falls, 3.2 km below White Lake	20	53	2019-2020
Total Future Potential		2,266	6,814	

Source: OPA

Table 4.6 – Actions on Options for Transmission in Medium Term (2011-2015)

Project #	Project Name	Reasons For Transmission Facilities	Facilities Description	Work Type	Completion Date	Estimated cost ($M)
	Bulk Transmission					
3	North-South Transmission Reinforcement	Increased Generation	ROW for two new 500 kV lines from Sudbury to GTA	Individual EA	2011	5
7	Thunder Bay Off-Coal	Maintain Transfer Capability	ROW for 22 km 230 kV double-circuit line from Lakehead TS to Birch TS	Class EA	2010	1
8	Toronto Third Supply	Capacity and Security	ROW for 230 kV supply from Parkway TS to Downtown Toronto	Class EA	2010	5
9	GTA East Auto Reinforcement	Maintain Transfer Capability	Site for new 500/230 kV Oshawa Area TS	Class EA	2010	1
11	Barrie South Transmission Reinforcement	Increased Generation	70 km 500 kV single-circuit line from Essa TS to Claireville TS	Individual EA	2012	3
22	Thunder Bay Off-Coal	Maintain Transfer Capability	22 km 230 kV double-circuit line from Lakehead TS to Birch TS and 230/115 kV autos	Facilities	2013	60
23	GTA West Reinforcement	Maintain Transfer Capability	500/230 kV autos at Milton and 230 kV lines	Facilities	2014	200
24	Pleasant Line Upgrade	Increased Transfer Capability	Upgrade Hurontario SS to Pleasant TS 230 kV line section	Facilities	2013	15
25	Nanticoke Off-Coal	Maintain Transfer Capability	Shunts capacitors and SVC at Nanticoke	Facilities	2014	50
26	GTA East Auto Reinforcement	Maintain Transfer Capability	New 500/230 kV Oshawa Area TS with full switching	Facilities	2014	150
27	Barrie South Transmission Reinforcement	Increased Generation	70 km 500kV single-circuit line from Essa TS to Claireville TS	Facilities	2015	170
29	Kitchener-Waterloo-Cambridge-Guelph (KWCG)	Reliability	In-line breakers on Detweiler 230 kV circuits M20D/M21D	Facilities	2014	20
31	Toronto Third Supply	Capacity and Security	230 kV supply from Parkway TS to Downtown Toronto	Facilities	2016	600
	Enabler Connections					
12	Little Jackfish Hydro and East Nipigon Wind Development	Increased Generation	ROW for 185 km 230 kV single-circuit from Alexander SS to Little Jackfish GS	Individual EA	2010	1
13	Parry Sound Wind Development	Increased Generation	ROW for 100 km 230 kV double-circuit line from Parry Sound TS to Byng Inlet	Individual EA	2011	1
14	Goderich Area Wind Development	Increased Generation	Rebuild the 35 km 115 kV line from Goderich TS to Seaforth TS to a 230kV line	Class EA	2011	1
34	Little Jackfish and East Nipigon Wind Development	Increased Generation	185 km 230 kV sngle-circuit from Alexander SS to Little Jackfish GS	Facilities	2013	152
35	Goderich Area Wind Development	Increased Generation	Rebuild the 35 km 115 kV line from Goderich TS to Seaforth TS to a 230 kV double-circuit line and conversion of Goderich TS to 230 kV	Facilities	2014	63
36	Parry Sound Wind Development	Increased Generation	100 km 230 kV double-circuit line from Parry Sound TS to Byng Inlet	Facilities	2015	132

Source: OPA

4.3 Actions to Create Opportunities for Long Term

This category includes actions related to the resources required for implementation in the long term (2016-2027), including the exploration of opportunities showing resource potential.[19]

The full set of actions assigned to this category is summarized in Table 4.7 and Table 4.8 for CDM and supply resources and for transmission, respectively. For the transmission projects, the project numbers in the first column are shown in the maps in Figure 4.1.

[19] In the long-term category we mean those near-term action that represent the first of several milestones towards commitment of a resource. The development of the resource could be terminated at minimal cost. An example would be a study for a project that would not come into service for 10 or more years. It might be in the nature of an insurance project that is within a portfolio of several projects, only one of which may be chosen.

Table 4.7 – Actions on Opportunities for CDM and Supply in Long Term (2016-2027)

Resource Type	Reasons	Action
CDM		
CDM	Increased CDM	Develop additional 3,500 MW by 2027
		Implement CDM programs in residential, commercial and industrial sectors
		Enhance culture of conservation and CDM delivery capability
		Carry out detailed evaluation measurement and verification to confirm CDM savings or reductions achieved
Renewables		
Hydroelectric	Increased generation	Cooperate with various government ministries (MOE, MNR, MNDM), First Nations, and other hydroelectric proponents in rationalizing processes and policies to facilitate the development of the hydroelectric potential, in particular the undeveloped potential in northern Ontario such as along the Albany river
		Monitor hydroelectric developments on an on-going basis and assess their impacts on the IPSP
Renewables General		Develop additional 5,300 MW of new renewable between 2011 and 2025 to meet 2025 target
Nuclear Refurbishment		
Nuclear	Increased generation	Assess system and IPSP impacts of refurbishment programs on an on-going basis including future unit refurbishment outage schedules
New Nuclear		
Nuclear	Increased generation	OPG and Bruce Power to continue with environmental assessments seeking approval for new nuclear generation at the Darlington and Bruce sites, respectively
		OPG and Bruce Power to continue with feasibility studies for new nuclear generation (including consideration of alternative nuclear technologies) at the Darlington and Bruce sites, respectively
		Monitor developments on an on-going basis and assess their impacts on the IPSP

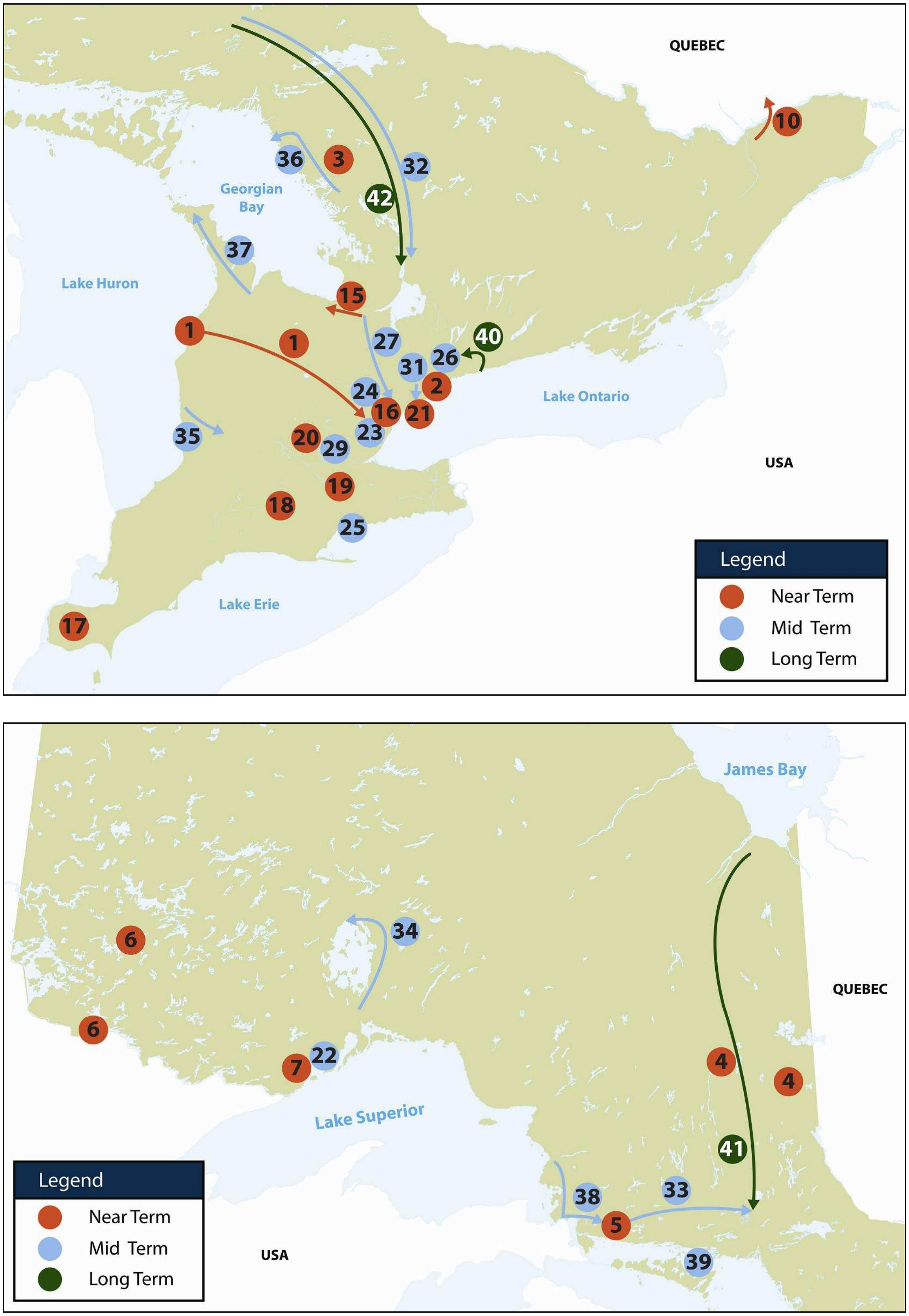
Source: OPA

Table 4.8 – Actions on Opportunities for Transmission in Long Term (2016-2027)

Project #	Project Name	Reasons For Transmission Facilities	Facilities Description	Work Type	Completion Date	Estimated cost ($M)
	Bulk Transmission					
28	Moose Basin Hydro Development	Increased Generation	ROW for two 550 km 500 kV lines from Moose Basin to Sudbury	Ind. EA	2015	2
29	Kitchener-Waterloo-Cambridge-Guelph (KWCG)	Reliability	In-line breakers on Detweiler 230 kV circuits D6V/D7V	Facilities	2017	20
30	Darlington B Incorporation	Increased Generation	ROW for 500kV double-circuit line from Bowmanville to Oshawa Area TS	Class EA	2015	2
32	North-South Transmission Reinforcement	Increased Generation	First new 500 kV single-circuit line from Sudbury to GTA	Facilities	2017	790
33	Sudbury West Transmission Reinforcement	Increased Generation	500 kV single-circuit line from Mississagi TS to Hanmer TS and conversion of existing 230 kV line for 500 kV operation	Facilities	2017	535
40	Darlington B Incorporation	Increased Generation	20 km 500 kV double-circuit line from Bowmanville SS to Oshawa Area TS	Facilities	2018	70
41	Moose Basin Hydro Development	Increased Generation	550 km 500 kV single-circuit line from Moose Basin to Sudbury	Facilities	2019	876
42	North-South Transmission Reinforcement	Increased Generation	Second new 500 kV single-circuit line from Sudbury to GTA	Facilities	2019	790
	Enabler Connections					
37	Bruce Peninsula Wind Development	Increased Generation	ROW for 80 km 230 kV single-circuit line from south of Tobermory to Owen Sound TS	Ind. EA	2014	1
			80 km 230 kV single-circuit from south of Tobermory to Owen Sound TS	Facilities	2017	91
38	East Lake Superior Wind and Pump Storage Development	Increased Generation	ROW for a 230 kV double-circuit line from 3rd Line TS to MacKay TS, and a 500 kV single-circuit line from 3rd Line TS to Mississagi TS	Ind. EA	2014	2
			91 km 230 kV double-circuit line from 3rd Line TS to MacKay TS (near Montreal River)	Facilities	2017	75
			76 km 500 kV single-circuit line from 3rd Line TS to Mississagi TS	Facilities	2017	106
39	Manitoulin Wind Development	Increased Generation	ROW for 100 km 230 kV single-circuit line from Espanola to Little Current to Wikwemikong	Ind. EA	2016	1
			Rebuild 115 kV line to 230 kVsingle-circuit line from Espanola to Little Current. Build a new 230 kV single-circuit line from Little Current to Wikwemikong	Facilities	2018	88

Source: OPA

Figure 4.1 – Transmission and Local Area Projects – Southern and Northern Ontario



Source: OPA

5. Appendix A: Minister's Directive

On June 13, 2006, Energy Minister Dwight Duncan directed the Ontario Power Authority (OPA) to proceed with its recommended 20-year electricity supply mix plan, with some revisions.[20]

The government directs the OPA to create an Integrated Power System Plan to meet the following goals:

- The goal for total peak demand reduction from conservation by 2025 is 6,300 MW. The plan should define programs and actions that aim to reduce projected peak demand by 1,350 MW by 2010, and by an additional 3,600 MW by 2025. The reductions of 1,350 MW and 3,600 MW are to be in addition to the 1,350 MW reduction set by the government as a target for achievement by 2007. The plan should assume conservation includes continued use by the government of vehicles such as energy-efficiency standards under the *Energy Efficiency Act* and the *Building Code*, and should include load reduction from initiatives such as geothermal heating and cooling; solar heating; fuel switching; small-scale (10 MW or less) customer-based electricity generation, including small-scale natural gas-fired cogeneration and trigeneration, and including generation encouraged by the recently finalized net metering regulation.
- Increase Ontario's use of renewable energy such as hydroelectric, wind, solar and biomass for electricity generation. The plan should assist the government in meeting its target for 2010 of increasing the installed capacity of new renewable energy sources by 2,700 MW from the 2003 base, and increase the total capacity of renewable energy sources used in Ontario to 15,700 MW by 2025.
- Plan for nuclear capacity to meet baseload electricity requirements but limit the installed in-service capacity of nuclear power over the life of the plan to 14,000 MW.
- Maintain the ability to use natural gas capacity at peak times and pursue applications that allow high-efficiency and high-value use of the fuel.
- Plan for coal-fired generation in Ontario to be replaced by cleaner sources in the earliest practical time frame that ensures adequate generating capacity and electricity system reliability in Ontario.
  The OPA should work closely with the IESO to propose a schedule for the replacement of coal-fired generation, taking into account feasible in-service dates for replacement generation and necessary transmission infrastructure.
- Strengthen the transmission system to:
  - enable the achievement of the supply mix goals set out in this directive
  - facilitate the development and use of renewable energy resources such as wind power, hydroelectric power and biomass in parts of the province where the most significant development opportunities exist

.[20] This section is taken from the directive and the Ontario Ministry of Energy's news release of June 13, 2006, McGuinty Government Delivers a Balanced Plan for Ontario's Electricity Future. See www.energy.gov.on.ca/index.cfm?fuseaction=english.news.

- promote system efficiency and congestion reduction, and facilitate the integration of new supply, all in a manner consistent with the need to cost-effectively maintain system reliability.

The plan should comply with Ontario Regulation 424/04 as revised from time to time.

In addition to the directive to the OPA, the government requested Ontario Power Generation (OPG) to undertake feasibility studies for refurbishing units at the Pickering and Darlington sites. This will include a review of the economic, technological and environmental aspects of refurbishment. As part of this initiative, OPG is to begin an environmental assessment of refurbishing the four existing units at Pickering B.

OPG is also to begin the work needed for a federal approvals process that would include an environmental assessment for the construction of new units at an existing nuclear facility. The government stated that although it prefers to use Canadian companies and technology, its first obligation is to the people of Ontario. Decisions will be made based on the best technology offered at the best price to Ontario ratepayers.

Transmission capacity from Bruce County and surrounding area is to be expanded to facilitate the transmission of electricity from several new wind farms and the Bruce nuclear facility to Ontario homes and businesses.

The minister's directive to the OPA was guided by a number of core principles:

- ensuring the reliability of energy in Ontario over the long term
- ensuring stable energy prices for Ontarians
- supporting Ontario businesses in creating a climate for future investment
- increasing the use of green, renewable energy
- integrating greater energy efficiency through conservation into Ontario's long-term energy planning
- a commitment to replacing coal-fired generation.

6. Appendix B: Methodology and Assumptions for Resource Analysis

This appendix provides an overview of the tools and methodology being used to develop the IPSP.

The first section describes the Multi-Area Reliability Simulation (MARS) model. MARS is used to determine the planning reserve margin required to meet the generation adequacy criteria established by the Northeast Power Coordinating Council (NPCC). Based on MARS studies, it was determined that for the Preliminary Plan a planning reserve of 17 percent is required for the period 2008 to 2019. A planning reserve margin of 18 percent is required thereafter. These values will be confirmed for the IPSP.

The second section describes the PROSYM and Portfolio Screening Model (PSM) models. These models simulate the hourly operation of the generation and CDM resources planned to meet peak demand and planning reserve requirements in each year. They are used to forecast hourly generating unit energy production and system marginal costs, and to assess the need for baseload, intermediate and peaking resources. PROSYM is a detailed system simulation model that is well established in the industry, but is time-consuming to set-up and run. PSM may be thought of as a simplified version of PROSYM with respect to dispatching resources for each hour. Because of its simplicity, PSM can be used in performing Monte Carlo assessments, where thousands of different combinations of system resources and conditions are conducted to generate risk profiles that are statistically significant. PSM was not used in developing the Preliminary Plan.

The third section describes the financial evaluation analytic framework, showing the links and interchanges between the PROSYM, PSM, Levelized Unit Energy Cost (LUEC) and cost to customer models.

Multi-Area Reliability Simulation (MARS) Program

General Electric's MARS program[21] is a tool used to assess the ability of a power system comprising a number of interconnected areas to adequately satisfy customer load requirements within each area. Based on a full sequential Monte Carlo simulation, MARS performs a chronological hourly simulation of the system, comparing the hourly load demand in each area to the total available generation in the area, that has been adjusted to account for planned maintenance and randomly occurring forced outages. Areas with excess capacity will provide emergency assistance to those areas that are deficient, subject to the transfer limits between the areas.

MARS calculates the standard reliability indices of daily and hourly LOLE (Loss of Load Expectation) and expected un-served energy, along with time-correlated indices such as

[21] See: http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm

frequency and duration of outage events. The program can also calculate the expected number of days per year that various emergency operating procedures would need to be implemented.

MARS was used to determine the required level of planning reserve necessary to meet the NPCC LOLE criterion of one day in 10 years.

PROSYM

PROSYM is a multi-area fundamental electric energy production simulation model developed by Global Energy Decisions Inc. It is an hourly chronological simulation engine for least-cost optimal production dispatch (i.e., dispatch is based on the resources' marginal costs), with full representation of generating unit characteristics, network topology and electrical loads. PROSYM also considers and respects operational and chronological constraints, such as minimum up and down times, random forced outages and transmission capacity. It is designed to simulate the functioning of the electric market and determines the station generation, costs and economic transactions between interconnected areas for each hour in the simulation period.

Portfolio Screening Model

The PSM is also an electric energy production simulation model; however, it makes a number of simplifying assumptions relative to PROSYM. There is no modelling of generating unit operational constraints (such as ramp rate limitations), the availability or price of power imports from neighbouring jurisdictions, or transmission limitations within Ontario. Consequently, PSM requires much less computing time the PROSYM to model a given resource portfolio.

PROSYM and PSM are used in tandem. PSM can be first calibrated against the more accurate PROSYM model and then applied to the large number of simulations required for risk analysis.

PSM was initially developed by Navigant Consulting, Inc. as an Excel-based analysis tool, and was subsequently modified by OPA. PSM consists of three modules: an input module, a dispatch module and a financial analysis module. It also has the capability of performing risk analysis (such as Monte Carlo analysis) through a stochastic simulation of several risk variables such as fuel prices and unit forced outages, where variables are selected randomly from an assumed probability distribution, hydroelectric and wind availability, capital cost and load.

PSM simulates the Ontario system for each hour of the 20-year period using a chronological merit order dispatch. This is on a "copper plate" basis, meaning that PSM does not model transmission-related power transfer limitations within Ontario.

PSM is used in the IPSP to provide financial assessments of portfolios and to perform Monte Carlo simulations for risk analysis. It is also used as to provide forecasts of system marginal costs.

Financial Evaluation Analytic Framework

A schematic of the analytic framework is given in Figure 6.1.

The IPSP database holds data that is common to all studies, such as generation capital costs, fuel cost forecasts and inflation rates.

The cost to customer model (Excel-based) forecasts the future cost to customers of electricity. It produces separate costs for residential, commercial and industrial customers.

The LUEC model (Excel-based) calculates the LUECs of the generation options. It is designed for easy parametric study of the impact of different capacity factors, fuel costs and discount rates.

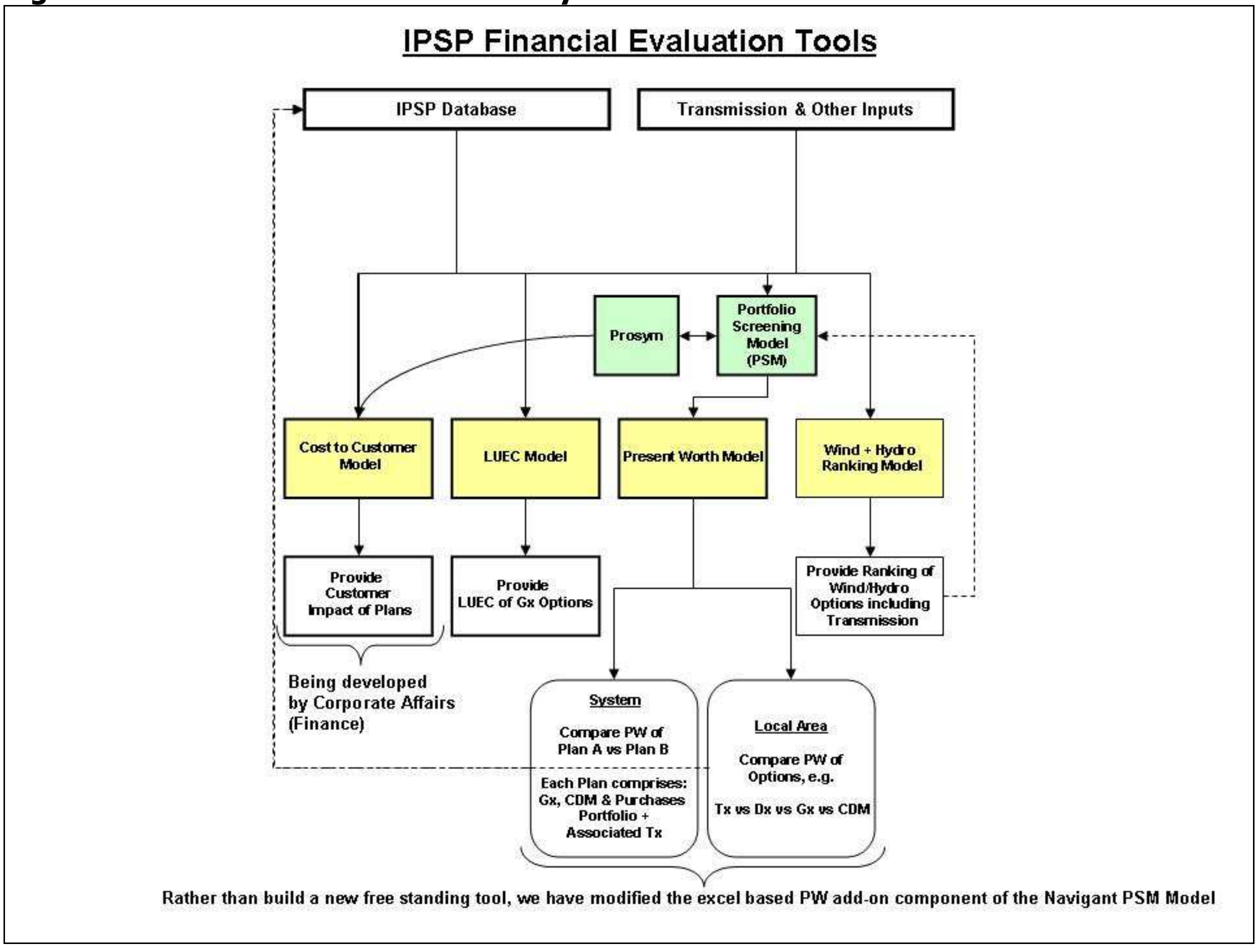
PSM calculates the total cost of building and operating Ontario's generation system as the result of any forecast demand and supply scenario. Transmission costs and constraints are not included. It is designed so that the impact of major uncertainties, such as fuel cost, capital cost, water availability and weather, can be modeled and the relative cost and financial risk assessed.

The PROSYM model provides a more detailed simulation of the future operation of the generation system. It is a multi-area model that allows for imports and exports, and models transmission constraints both within Ontario and with its interconnected markets. It provides information on the operability of the generation system, operating costs and marginal costs for the cost to customer model, and validation for the simpler PSM model.

The Present Worth Model allows comparison of alternative plans for either the total system or a local area. It takes the output of PSM and additional transmission capital and/or operating costs to determine the total present worth of the alternatives.

The Wind and Hydro Ranking Model provides a simple levelized cost comparison of various sites for ranking purposes. It includes the costs of the required transmission, either for connection or for regional reinforcement.

Figure 6.1 – Financial Evaluation Analytic Framework



Source: OPA

7. Appendix C: Cost to Customer Model

This section describes the component parts of a model being developed to identify the cost implications of the IPSP and describes underlying assumptions. The analysis is ongoing and will be presented as part of the final IPSP submission.

Introduction

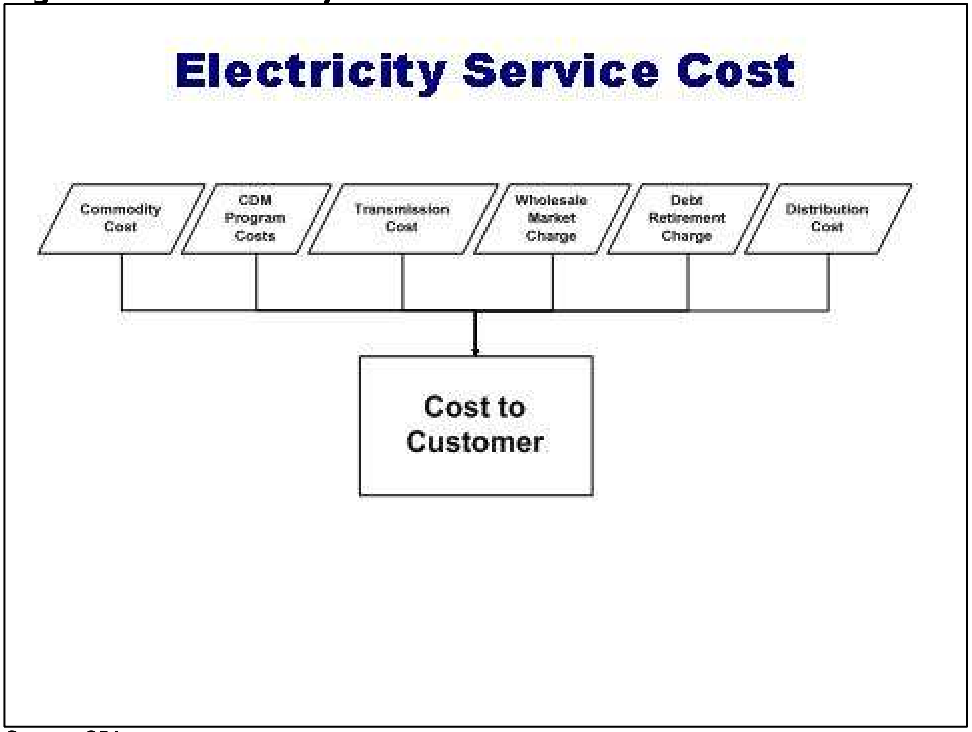
The IPSP will lay out the generation, delivery and CDM program costs that will be required to ensure there is an adequate, reliable and sustainable electricity sector to meet the needs of Ontarians.

The costs associated with the infrastructure for the electricity system and the electricity commodity costs are borne by the electricity consumers of Ontario. For the IPSP cost to customer analysis the cost of electricity is broken down and categorized into the following major cost components:

1. commodity (electricity) cost
2. conservation and demand management (CDM) costs
3. transmission cost
4. wholesale market charge
5. debt retirement charges
6. distribution cost.

This cost to customer model is developed to determine the impact of the Preliminary Plan's initiatives on electricity system cost. The general methodology of the cost to customer model is illustrated below:

Figure 7.1 – Electricity Service Cost



Source: OPA

The cost to customer model will also translate the total cost for each component to a unit cost by dividing the cost component by the total system demand to generate proxy rates for each component.

A more detailed discussion for each of the cost components of the cost to customer model is given in the following sections.

Commodity (Electricity) Cost

The commodity cost component is the payment to the generators for the production of the electricity commodity. The generation cost is different for each facility, as it depends on whether the generator has an obligation to supply its production based on a contractual agreed price, is paid a regulated price established by legislation/regulatory order or is selling at the market-clearing price for electricity. As a result, the Ontario electricity commodity price paid by customers comprises a combination of market price, regulated price and contract price.

The market-clearing price process is established by the IESO. For the IPSP, the PROSYM model will be used to provide an estimate of the hourly system marginal costs. This estimated hourly system marginal cost is be used as a proxy of the Hourly Ontario Energy Price (HOEP) in the cost to customer model. This is a simplifying assumption because prices are affected by factors other than marginal cost. For the purpose of estimating the long-term cost impacts, we consider this to be a useful indicator.

The commodity in this model is also differs from the true market clearing price, as the model uses the demand load at the generator's meter. As a result, the net energy market settlement amount that would normally be collected in via a wholesale market service charge is included in the commodity price. In effect the cost of energy losses of the transmission system associated with flow of electricity through the transmission lines is captured in the commodity component of the generators.

The commodity cost takes the supply mix dispatch of each facility and links it to a payment method appropriate for the generator. For example, there is a direct linking of the OPG nuclear generation station dispatch (specifically Darlington and Pickering) to the prescribed fixed rates established by the government as the cost the customer will pay for this generation (currently the government establishes this price, but in the future this rate will be set by the OEB).

The difference between the regulated and contract prices and the HOEP is captured in a global adjustment, which is the variance amount required to be paid by loads to ensure that the payment to the generator is equal to the contract or regulated price.

Moving forward in the planning period of the IPSP, Ontario will need to replace generation facilities, build new generation and refurbish existing facilities. For new generation and refurbishments of existing facilities, it is assumed that these facilities will obtain a price similar to the existing contract prices for similar types of facilities. This concept of using existing contract prices is viewed to be a reasonable means for the developer to recover the cost for its investment. While this may not be the way generators recover costs, it is a reasonable way to estimate the impact of new facilities on customer costs in the long term. Furthermore this methodology is useful in producing sensitivity analysis and trend analysis on the cost to customer amounts.

The major generation payment categories in the cost to customer model's commodity cost component can be categorized as follows:

1. marginal cost on the basis that is a proxy for the market-clearing price
2. regulated price, that is, the price is determined by legislation
3. contract price, which is a commercially negotiated contract
4. new generation and refurbished facilities, which are estimated to be consistent with existing contract prices.

1. Market-Clearing Price (Marginal Cost)

Some generation used to meet system demand in Ontario is supplied at the market-clearing price. This price is established through the IESO's market bidding process by stacking the lowest to highest bid prices to meet system demand.

The PROSYM model will be used to provide an estimate of the hourly system marginal costs based on the supply mix in the Preliminary Plan. This estimate will assume no transmission constraints, to be consistent with the IESO's methodology for calculating HOEP. Furthermore, this estimated hourly system marginal cost is to be used as a proxy of the HOEP in the cost to customer model. As a result, this proxy HOEP will not assume any bidding strategies that a generator may consider in its bidding into the market that establishes the market-clearing price. In effect, the marginal cost is the assumed market price for the generation supply sold in the electricity market.

2. Regulated Price

The OPG generators are priced under various cost regimes, with a significant portion of their production priced at a rate that has been established by legislation or regulatory order. Table 7.1 summarizes the current regulatory regimes that apply to various OPG generators.

Table 7.1 – OPG Generator Regulatory Regime

OPG Prescribed Assets	OPG Non-Prescribed Assets	
	Revenue Limited (Set Price)[1]	Merchant[2]
Baseload Hydro Production <= 1,900 MW @ $33.00/MWh	85% of Intermediate & Peaking Hydro Production	Baseload Hydro Production > 1,900 MW
All Nuclear Production @ $49.50/MWh	85% of All Coal Production	15% of remaining revenue limited production
		Lennox output

Notes: 1. See section 2b below. 2. Market-clearing price or reliability-must-run contract
Source: OPA

A portion of OPG's production receives the market-clearing price or in the case of Lennox, reliability-must-run contract and is thus not subject to a global adjustment or rebate as discussed below.

Ontario Power Generation (OPG) Prescribed Assets
The OPG prescribed assets are baseload generation stations owned by Ontario Power Generation that provide electricity consistently thorough the day or night. The prescribed generation facilities are the nuclear generating stations operated by OPG (Pickering and Darlington) and OPG's baseload hydroelectric generation facilities (De Cew I, De Cew II, Sir Adam Beck I, Sir Adam Beck II, Sir Adam Beck pumped generating station and R.H. Saunders).

Currently, OPG receives a fixed rate of 3.3 cents/kWh for the first 1,900 MW of electricity generated by the baseload hydroelectric stations in any given hour. Output over 1,900 MW receives the market-clearing price. For the nuclear plants, OPG receives a fixed rate of 4.95 cents/kWh. These current rates have been set by the government to apply until March 31, 2008. After the expiry of these rates, the Ontario Energy Board will have the authority to determine payment amounts for the prescribed generation facilities commences on April 1, 2008.

On March 21, 2006, the OEB initiated a process to establish a methodology to determine the price that should be paid for the OPG prescribed assets to be effective after the expiry of the government set rates. The regulatory models presented by the OEB for discussion in this process are: 1) cost of service, 2) incentive regulation, and 3) regulatory contracts. Completion of this process is still pending, and is not available for the IPSP Preliminary Plan.

As a result, for this IPSP analysis the price for the OPG prescribed units is assumed to remain constant at the last established price set by the government for the 2010 to 2025 planning period. The commodity cost for the OPG prescribed units will be assumed to be locked in at 3.3 cents/kWh for the first 1,900 MW of hydroelectric generation, and 4.95 cents/kWh for nuclear production in real terms for the period of the IPSP.

For the facilities that are refurbished during the IPSP planning period, the regulated price noted above is adjusted to a contract price that is consistent to a similar existing type of facility that includes refurbishment expenses. For example if a prescribed nuclear plant is refurbished the price for that facility will be charged a higher rate. For the cost analysis a lower and upper band price is used to recognize the level uncertainty surrounding this estimate.

In order to ensure that the customer pays the established prescribed price for the OPG Prescribed Assets volumes the HOEP payment to OPG is adjusted by a global adjustment amount. The global adjustment is the variance collected between the prescribed amount and the HOEP amount collected, which ensures the cost recovered from customer is the established prescribed price.

OPG Non-Prescribed Assets
The OPG non-prescribed assets are also categorized as having a regulated rate as the revenue for these facilities is determined by legislated rates. However, the government has established that OPG non-prescribed assets have a revenue limit. The variance between the amount the generator obtains from HOEP and its set price is captured through an OPG rebate. The OPG non-prescribed assets are the following hydroelectric and fossil-fired generation facilities:

Table 7.2 – OPG Non-Prescribed Assets - Hydroelectric

Abitibi Canyon GS	Kipling GS
Aguasabon GS	Lakefield GS
Alexander Falls GS	Little Long GS
Arnprior GS	Lower Notch GS
Auburn GS	Lower Sturgeon Falls GS
Barrett Chute GS	Manitou Falls GS
Big Chute GS	Matabitchuan GS
Big Eddy GS	McVittie GS
Bingham Chute GS	Merrickville GS
Calabogie GS	Meyersburg GS
Cameron Falls GS	Mountain Chute GS
Caribou Falls GS	Nipissing GS
Chats Falls GS	Otter Rapids GS
Chenaux GS	Otto Holden GS
Coniston GS	Pine Portage GS
Crystal Falls GS	Ragged Rapids GS
Des Joachims GS	Ranney Falls GS
Ear Falls GS	Sandy Falls GS
Elliott Chute GS	Seymour GS
Eugenia GS	Sidney GS
Frankford GS	Sills Island GS
Hagues Reach GS	Silver Falls GS
Hanna Chute GS	Smoky Falls GS
Harmon GS	South Falls GS
High Falls GS	Stewartville GS
Hound Chute GS	Stinson GS
Indian Chute GS	Tretheway Falls
Kakabeka GS	Wawaitin Falls GS
	Whitedog Falls GS

Source: OPA

Table 7.3 – OPG Non-Prescribed Units – Fossil

Lambton	Thunder Bay
Atikokan	Nanticoke

Source: OPA

The Ontario government has established a rebate on 85 percent of the output from OPG's coal-fired and smaller hydroelectric operations, by way of refunding monies collected above a set price. This rebate is known as the OPG Rebate. On February 9, 2006, the government announced an initiative to improve price stability for consumers, by extending and initially lowering the transitional revenue limit as follows:

- 4.6 cents/kWh from May 1, 2006, to April 30, 2007
- 4.7 cents/kWh from May 1, 2007, to April 30, 2008

- 4.8 cents/kWh from May 1, 2008, to April 30, 2009.

The OPG rebate ensures that the facilities are paid the capped rate for 85 percent of its output and that appropriate credit will flow to the customer.

For the IPSP Preliminary Plan, the cost to customer model assumes that the last fixed price established by the government of 4.8 cents/kWh is held constant in real terms for the planning horizon.

3. Contract Price

The contract price facilities include the non-utility generators (NUGs) and OPA contracts. For the contract price facilities, the variance between the amount the generator obtains from HOEP and its contract price is captured through the global adjustment factor. The global adjustment ensures that the contract price negotiated by the generator is paid by the loads.

Non-Utility Generators (NUGs)
The NUGs are privately owned generators who signed contracts with the former Ontario Hydro that are still in force today. The NUG contracts expire at various dates up to 2048. The Ministry of Finance estimates that the bulk of the existing electricity contracts will expire in 12 years. Currently, total capacity of the NUGs portfolio is about 1,700 MW or about six percent of Ontario's generating capacity.

Given that the NUG contracts are confidential contracts, the specific pricing of these terms is not available for establishing the commodity cost component for the cost to customer model. To establish an estimated price for the NUG contracts historical data for 2005 was used to provide an estimate for the future cost.

For the IPSP planning period, the commodity cost for the NUG contracts is assumed to be a 2005 historical annual rate[22]. As the NUG contracts expire it is assumed that the dispatch from these facilities will receive a price similar to the OPA CES contract price.

In order for the commodity cost to reflect a NUG contract price, the variance amount between the NUG rate and the HOEP is captured in the global adjustment mechanism and flowed through to the customers in the commodity cost component.

OPA Contracts
The OPA has contracts as a result of the Ontario government's or the OPA's request for proposals (RFPs) for clean or renewable energy production and demand management measures, and also a number of other private generators that offer supply into the wholesale market. The latter will receive basic investment guarantees but will need to participate in the market to ensure a full return on investment.

The commodity cost for OPA contracts is modelled on the basis of the contractual agreements. Given that the contract prices are impacted by input costs or other factors there is an assumed price range for these contracts in the analysis. In the event an OPA contract reaches its expiry

[22] Given that the cost analysis is produced in 2006 constant dollars, the 2005 historical rate is inflated to 2006 dollars and held constant for the IPSP planning horizon.

date during the IPSP planning period, it is assumed that the facility will obtain the marginal cost for its dispatch.

4. New Generation Units and Refurbishment of Existing Facilities

For new generation and refurbishments of existing facilities, it is assumed that these facilities will obtain a price similar to the existing contract prices for similar types of facilities. This concept of using existing contract prices is viewed to be a reasonable means for the developer to recover the cost for its investment. While this may not be the way generators recover its costs, it is a reasonable way to estimate the impact of new facilities on customer costs in the long term. Furthermore this methodology is useful in producing sensitivity analysis and trend analysis on the cost to customer amounts.

This commodity component is designed to allow for a lower and upper bound of prices to be adopted for different generation types such as: new nuclear, new renewables, new gas, standard offer dispatchable, standard offer non-dispatchable, standard offer solar, and refurbished nuclear. The use of a lower and upper bound price recognizes there is uncertainty surrounding the estimates.

For the Preliminary Plan the new nuclear plant has a lower bound that is slightly above the Bruce A contract with an upper bound price equal to that of the upper bound price of the refurbished nuclear plants. The new gas-fired generation plant is priced consistent with the OPA CES contract and a new renewable facility is priced consistent with the OPA RES contract. The standard offer prices are assumed be higher price generation relative to traditional large facilities. In the event, a prescribed facility requires refurbishment during the IPSP planning period the current regulated price will be adjusted to a higher refurbished contract price.

CDM Program Costs

Previously, the costs associated with CDM programs were recovered from customers by way of increased distribution costs from the electrical Local Distribution Companies (LDCs). On May 31, 2004, the Minister of Energy encouraged LDCs to submit plans to the OEB for $163 million worth of CDM projects to be initiated over a three year period. LDCs were required to obtain the funding of the CDM projects from the OEB by way of their third instalment (“tranche”) of incremental Market Adjusted Revenue Requirement (MARR). This third tranche funding is expected to end as of September 30, 2007.

On July 13, 2006, the OPA was provided with direction from the Minister to assume responsibility to coordinate and fund the delivery of electricity conservation and demand-side management (CDM) programs by local distribution companies in Ontario, on or before October 1, 2007. This direction for the OPA is to be carried out under specific guidelines, in particular with the funding of CDM for the three year funding cycle starting on or before October 1, 2007, to be limited to $400 million. The funds would be collected under a “Global Adjustment Mechanism” to the approved level.

Further to the OPA-administered LDC fund, the Conservation Bureau in the OPA also ensures that all areas of the province have access to an appropriate set of CDM programs. As a result, the Conservation Bureau, on its own initiative, will be carrying out CDM programs and initiatives to assist the Government of Ontario in achieving its goals to electricity conservation and demand management. The costs for OPA-lead CDM programs and initiatives, inclusive of incentive payments for customers to curtail consumption, will also be recovered from customers.

The CDM costs in accordance to legislation is recovered from customers in the commodity rate via the Global Adjustment Mechanism, for the IPSP analysis the CDM costs to customers is identified as a separate cost component to provide greater transparency in the analysis of cost to customers. The program costs and incentive payments assumed in the IPSP will be recovered by customers by way of incremental layer of revenue that will be required from Ontario consumers. The CDM program costs and incentive payments will be consistent with the IPSP demand reduction proposed in the plan.

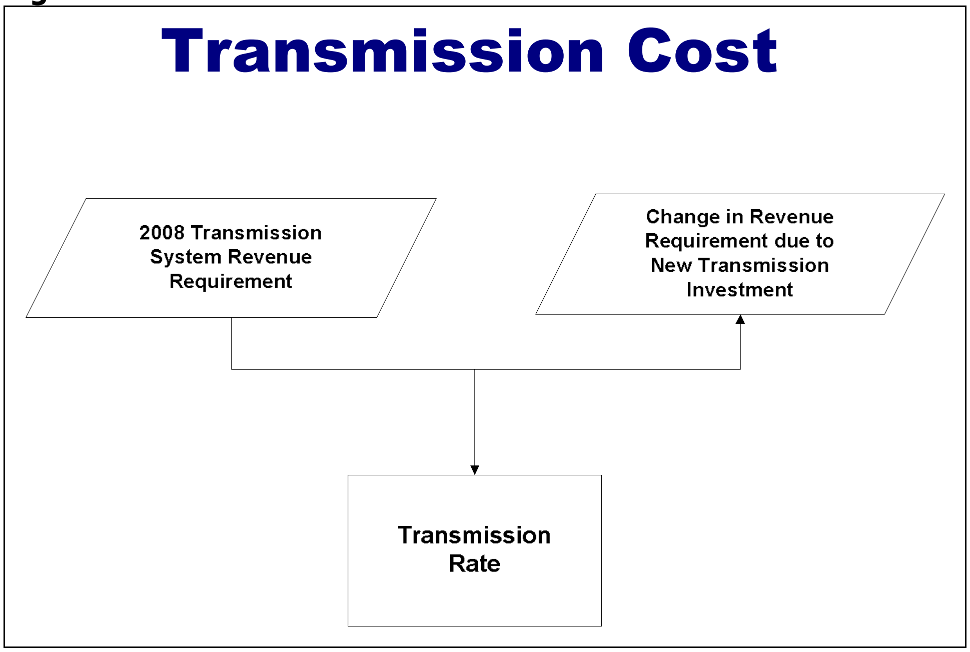
Transmission Costs

The infrastructure of high-voltage transformers and lines that deliver the electricity from the generating stations to the consuming regions is the transmission system. The transmission system is a high voltage system that operates at 500 kV, 345 kV, 230 kV, 115 kV and 69 kV, and is designed to transmit electricity from directly connected generation systems to Local Distribution Companies (LDCs) and end-use transmission customers. The transmission system interconnects the facilities of neighbouring provinces and states, specifically Manitoba, Quebec, Minnesota, Michigan and New York, to enable the transfer of electrical energy between Ontario and these jurisdictions.

The Ontario transmission system is owned by the following transmission companies: Hydro One Transmission, Great Lakes Power, Canadian Niagara Power, and Five Nations Energy, with Hydro One Transmission accounting for 96.3 percent of the total transmission revenue requirement for the province. The remaining 3.7 percent of the cost of transmission for the province of Ontario is as follows: Great Lakes Power is 2.9 percent, Canadian Niagara Power is 0.4 percent, and Five Nations Energy is 0.4 percent.

The methodology to capture the transmission cost in the cost to customer model is to take a base cost of transmission and layer on the incremental revenue requirement associated with additional incremental capital and operating and maintenance (O&M) costs for new facilities assumed to be added during the planning period. An illustration of these two major cost components used to generate the transmission costs for the cost to customer model is provided below.

Figure 7.2 – Transmission Cost



Source: OPA

The cost associated with the transmission infrastructure is recovered from the customers of Ontario through transmission charges approved by the Ontario Energy Board. On September 12, 2006, Hydro One Transmission applied to the Ontario Energy Board for approval of a revenue requirement for 2007 and 2008 of $1,263 million and $1,298 million, respectively. This transmission rate application by the largest transmission company in Ontario comprises a significant portion of the base transmission assumptions for the cost to customer model.

The 2008 base transmission is assumed to be $1,298 million plus the 2005 revenue requirement of the other transmission facilities (i.e., those of Great Lakes Power, Canadian Niagara Power, and Five Nations Energy). This base revenue requirement is assumed throughout the IPSP planning period.

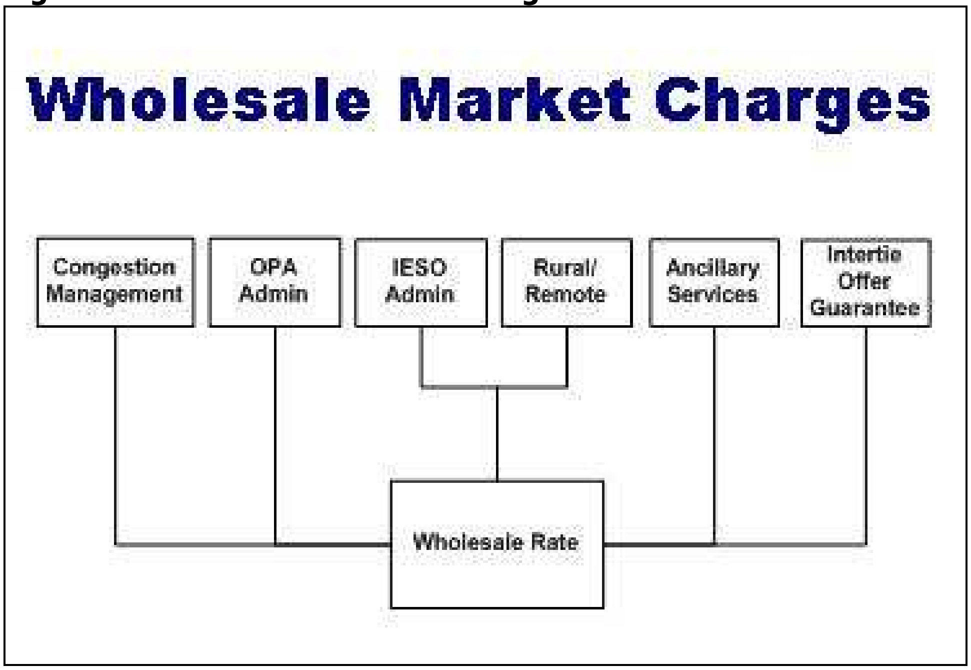
The revenue requirement for any new transmission expansion associated with the IPSP will be layered on top of the base revenue requirement to capture the incremental transmission costs of the new facilities. The assumptions for the debt/equity ratio, cost of debt and return on equity for the new transmission facilities are assumed to be consistent with the Hydro One Transmission Application (EB-2006-0501).

Wholesale Market Charges

The wholesale market charges cover the cost of service that is essential for operating the electricity system and running the electricity market. The list of charges in this category that the IESO flows through to customers is extensive and variable in nature. A comprehensive list of wholesale charge types is provided at the following IESO link: http://www.ieso.ca/imoweb/pubs/settlements/IMO_Charge_Types_and_Equations.pdf.

The cost to customer model breaks down the wholesale charges it needs to recover into the following major charge components as shown in the following figure.

Figure 7.3– Wholesale Market Charges



Source: OPA

A discussion of each of these wholesale charge components follows.

Congestion Management Settlement Uplift

The market clearing price for Ontario is determined by using an ideal system where there are no physical limitations on the transmission of power. However, the physical system prevents this ideal dispatch from being realized, as there may be capacity constraints on the lines.

In order to preserve the integrity of the power grid, the IESO's dispatch instructions must take these constraints on the transmission lines into account. When there are constraints on the lines (congestion), actual dispatch instructions may be different from what we would expect, but the market clearing price does not change. However, in order to maintain fairness in the market, generators and loads are paid 'constrained-on' and 'constrained-off' payments if they are affected by transmission line limitations.

In order to estimate constraint payments in the cost to customer calculation, the PROSYM model will be re-run with key system interface limits modeled. The limit values will be estimated in to be consistent to the transmission planned enhancements. PROSYM will calculate the annual variable cost of each generator (variable O&M plus fuel cost). The difference in the sum of the annual variable costs for all generators, between the constrained run and the unconstrained run, represents the cost of congestion. This is the value that will be used on the cost to customer model.

Ontario Power Authority (OPA) Administration Rate

The OPA charges its expenses associated with carrying out its legislative and directive related mandates for long-term planning, capacity procurement, conservation initiatives, and market evolution to customers through its revenue requirement application. This revenue requirement is submitted to the Ontario Energy Board for approval and recovery from customers.

For the cost to customer model, the 2007 revenue requirement (EB-2006-0233) for the OPA of $57.0 million is translated into a unit rate of $0.40/MWh and held constant for the IPSP planning period.

Independent Electricity System Operator (IESO) Administration Rate

The IESO charges administrative costs to operate the wholesale electricity market and electricity power system in Ontario. This revenue requirement is approved by the Ontario Energy Board.

In IESO's 2007-2009 Business Plan, the 2007 usage fee requirement is $133.3 million. For the cost to customer model this amount is translated into a unit rate of $0.80/MWh and is held constant, to generate the IESO administration cost to be recovered from the customer.

Rural/Remote Settlement Rate

The Rural or Remote Electricity Rate Protection rate is used to partially offset the higher costs of providing electricity in rural/remote areas. This rate is fixed at 0.1 cents/kWh and is established by regulation.

For the cost to customer model this rate has been held constant in real terms for the planning period of the IPSP.

Ancillary Services

In order to ensure reliability operations of the power system the IESO contracts for a number of ancillary services. The ancillary services include the operating reserves, black start capability, regulation services as well as reactive support and voltage control. The operating reserve service is associated with stand-by power required in case of an unexpected reduction in power supplied from a generator. Black start capability is a generator’s ability to help restore the province’s power system in the case of emergency. The regulation service represents the ability of a generator to control its generation output on a second-by-second basis so that the IESO can adjust imbalances between load and generation by using the generator’s automatic generation control (AGC) capacity. The reactive support and voltage control service is a service provided by generators that allow the IESO to maintain consistent reactive power and voltage levels on the grid. These rates and charges vary by the hour.

The 2005 historical year cost for ancillary services is converted into a unit cost and held constant for the IPSP planning period. For the cost to customer model, the 2005 historical actual is held constant in real terms to capture this ancillary service cost.

Intertie Offer Guarantee (IOG)

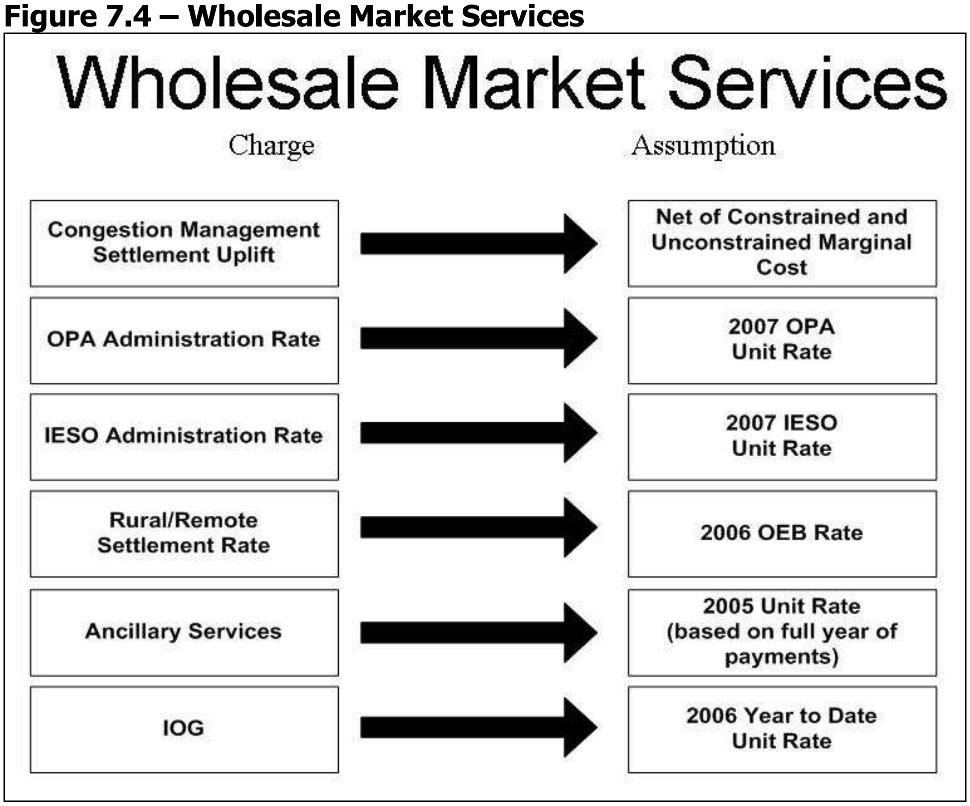
The Ontario energy market has been designed to allow market participants to import power from and export power to other jurisdictions. Because the source (or destination in the case of exports) is outside the Ontario control area, imports and exports cannot be dealt with in the same way as internal supply and demand. Import and exports are scheduled an hour in advance which means that an import that is to take place between 11:00 to 12:00 will be locked in shortly after 10:00, during the hour-ahead pre-dispatch run of the scheduling algorithm. In the event, the energy from the import or export can not flow, or if the Ontario price is different, there is an extra price risk to the importer and exporter.

Given this risk to the imports and the need for ensure adequacy of supply to Ontario, the IESO offers an Inter-tie Offer Guarantee (IOG) payment to reduce the price risk to imports. This IOG payment ensures that over the course of the hour an importer will receive at least the accepted offer price and will not suffer a negative impact if the real-time inter-tie zone price is lower.

For the cost to customer model, the 2006 year to date unit rate has been adopted for the IPSP planning period and held constant in real terms.

The following figure summarizes the assumptions for the various wholesale market charges used in the cost to customer model:

Figure 7.4 – Wholesale Market Services



Source: OPA

Debt Retirement Charge (DRC)

The Electricity Act, 1998 imposes a charge, known as the Debt Retirement Charge (DRC) which is payable on electricity consumed in Ontario. The DRC is a 0.7 cents per kilowatt hour charge for electricity consumed in most Ontario communities.

All revenues from DRC will be used exclusively to pay down the residual stranded debt of the former Ontario Hydro. In the cost to customer model the DRC rate of 0.7 cents/kWh rate is fixed in nominal terms from 2008 to 2020. By 2020, the DRC is projected to end, as the residual stranded debt is expected to be extinguished.

Distribution Costs

The distribution cost is the cost for delivering electricity from the transmission system to an end-user's location such as a home. The distribution system is the portion of the electricity system infrastructure at a voltage level below 50 kilovolts that delivers the electricity to lower voltage users such as homeowners, apartments, and local commercial and industrial sites.

Currently, there are over 90 electricity distributors in Ontario that are regulated by the OEB. To streamline the approval process for these distributors the 2006 Electricity Distribution Rate Handbook (RP-2004-0188) was issued on May 11, 2005. The handbook contained requirements and guidelines for filing an application. LDCs filed individual applications in mid-2005 which contained their revenue requirement inclusive of an amount for the recovery of regulatory assets.

The regulatory asset amounts sought were associated with the variety of costs LDCs incurred in preparation for the competitive market, which opened in May 2002. In addition to these costs, LDCs have incurred other costs associated with regulatory directives related to market restructuring and the ongoing competitive market. All of these costs for retail settlements, power purchases and market readiness were recorded in deferral accounts to be recovered through a rate rider over a four-year period.

On January 15, 2004, the Ontario Energy Board issued a decision concerning the application for the recovery of Regulatory Assets for the April 1, 2004 distribution rate adjustments. Known as Phase 1, the distributors applied for the recovery in rates of up to 25 percent of their total Regulatory Assets), or more if required for rate stability, on an interim basis beginning April 1, 2004. In Phase 2, the current phase, final recovery of costs, began on May 1, 2005 with the bulk costs commencing in May 2006.

The methodology of capturing the distribution cost in the cost to customer model is to take the approved total revenue requirement of all LDCs, net of the regulatory asset recovery amount, and divide it into Residential, Commercial and Industrial categories, based on the market retail proportions used in the IPSP. The total approved 2006 distribution cost net of the regulatory asset recovery amount is held constant for the planning period. The regulatory asset recovery amount is excluded from the distribution revenue requirement since this is an interim cost set to begin tapering off in 2008, and set such that it will disappear in 2010.

With respect to distribution costs subsequent to 2006, the OEB is currently discussing a 2nd Generation Incentive Regulation Mechanism (EB-2006-0089) regarding the establishment of future distribution revenue requirements and rates. For the cost to customer model it is assumed that the current 2006 revenue requirement levels in real terms are held constant for the 20-year term of the IPSP.

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8. Appendix D: Support Provided by Other Organizations to OPA

In order to produce the IPSP, the OPA has relied on a number of organizations to provide analytical services, data and information.

IESO - Analytical Services

The OPA has an ongoing need for power system planning analysis and support in the form of system studies encompassing both transmission and generation. The system studies will need to review and assess both existing capabilities and future requirements. Considerable modeling expertise, specialized simulation tools and data collection from many sources are required to perform the necessary analysis and study work. The IESO can effectively provide this support given the infrastructure; process and staff currently in place to perform similar assessments for it own purposes and those of the marketplace in general. A master services agreement was executed in April 2006 between the OPA and IESO for power system planning studies and support. This agreement has a term of one year.

The OPA had decided to capture the strength of two load forecasting methodologies in preparing the IPSP. The first methodology is based on the Canadian Integrated Modelling System (CIMS) and the second is based on the IESO's econometric framework. In this regard the IESO supported the OPA in preparing a 20-year load forecast based on econometric methodology as well as other related sensitivity cases.

The IESO performed analytical studies to support the OPA to assess system adequacy for existing and potential new facilities.

The IESO also performed analytical studies to support the OPA to determine the required reserve level under various generation mix scenarios. These studies were carried out using the Multi-Area Reliability Simulation (MARS) tool. The IESO also made available its schematic base maps of Ontario.

Ontario Power Generation – Modelling Services

The OPA has an ongoing need to undertake extensive computer modelling of Ontario electricity supply sources and the power market under a wide range of planning scenarios. With limited time available to produce this first IPSP, it was not considered practical for the OPA to develop or acquire detailed resource planning models since they take too long to develop, are costly to acquire and need extensive data and knowledgeable and experienced staff to operate effectively.

The OPA approached OPG and requested that OPG make available its PROSYM computer model, calibrated by OPG for the Ontario Market, and related database. A formal agreement was executed in June 2006 between OPG and OPA which stipulates conditions and fees for the provision of OPG data and services. The agreement also includes a non-disclosure requirement for OPG that covers the small OPG team providing the modelling support, as well as measures to ensure IT and physical security. OPG has implemented a number of controls to mitigate regulatory risks, including competition and market surveillance concerns, and the Market Surveillance Panel of the Ontario Energy Board has confirmed that these controls are acceptable.

Studies using the computer model were conducted by OPA staff using data provided by OPG and other organizations, as described in the Table below. It is important to note that all modeling work was directed by the OPA and the OPA was solely responsible for all analysis and conclusions drawn from the modeling data.

Provision of Data and Information

The OPA gratefully acknowledges the important data and information provided by various organizations for use in preparing the IPSP. Table 8.1 summarizes the data and information provided to the OPA by these organizations.

Table 8.1 – Support Provided by Other Organizations to OPA

Organization	Data and Information Provided
Brookfield Power	Information related to the historical and planned production of Brookfield Power hydro-electric generating units. Transmission connection options and estimated costs.
Bruce Power	Data related to the performance characteristics and future plans for Bruce Power generating units.
Canadian Wind Energy Association	Arranging for confidential wind data to be provided by Ontario wind power developers to AWS Truewind, the consultant that collaborated with GE to produce the study on wind integration.
Hydro One Networks	Information related to equipment capabilities, physical characteristics, and historical loading. Access to Hydro One's GIS data set of transmission facilities and maps/diagrams. Transmission and distribution study results, solution options and associated costs. Transmission capabilities for future configurations. Support in developing load profiles for use in load forecast and CDM.
IESO	Information related to system operation and existing or potential constraints. Planning reliability criteria. System operating diagrams, maps and base cases. Historical data for demand, flows and other system quantities. 20-year load forecast data and sensitivity cases.
Ontario Ministry of Natural Resources	Data and information regarding potential hydroelectric development sites.
Ontario Power Generation	Data and information related to the performance characteristics and future plans for its thermal generating units. Data and information on OPG's estimates of refurbishment potential and feasible in-service dates for refurbished units at Pickering B if the OPG Board decides to refurbish the units. Data and information regarding the historical and planned production from existing and future planned hydroelectric generating plants.
Ontario Waterpower Association	Data and information regarding Ontario waterpower generation potential and costs.

Source: OPA

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9. Appendix E: Environmental Performance Assessment Methodology

Paragraph 7 of Section 2(1) of the IPSP regulation (424/04) requires the OPA to "ensure that safety, environmental protection and environmental sustainability are considered in the plan." The OPA's consideration of these factors started in 2005 in developing the *Supply Mix Advice Report* and continues with the development of the IPSP. This section outlines the OPA's proposed methodology, data and assumptions that will form the basis by which these elements will be considered in developing the IPSP.

The consideration of sustainability includes the entire plan, with site- and technology-specific information used to adapt generic environmental performance data to an Ontario context. Accounting for the specificity of the plan elements will be achieved by modifying environmental performance data based on context specific impacts. The specific environmental performance data for generation and transmission options (greenhouse gases, contaminant air emissions, etc.), assumptions for the modifiers and an example of the assessment results are included in this section.

For the IPSP, the OPA is working with SENES Consultants Limited to update and expand the environmental work completed for the *Supply Mix Advice Report*.[23] This update will include a more refined set of environmental performance data for electricity generation options, based on site-specific information for the electricity resources proposed in the IPSP. The assessment is expanded beyond supply resources to include transmission, with the capability to incorporate CDM as new information becomes known.

Refining the assessment framework is ongoing as the IPSP is being developed, but the analysis completed to date is being shared to enhance the upcoming stakeholder engagement activities.

Overview of Assessment Methodology

There are six steps employed to evaluate the environmental performance of the IPSP, based on six indicators. The steps of the methodology are summarized in the points below and described in more detail in the following sub-sections.

- collecting environmental data that describe emissions rates, water use, land use requirements and the generation of wastes for supply and transmission options, where available
- aggregating data into indices according to general categories of environmental impacts, where appropriate (e.g., conventional contaminant air emissions and greenhouse gases)
- developing modifiers to account for site specificity of options and potential impacts

[23] SENES Consultants Ltd., *Methods to Assess the Impacts on the Natural Environment of Generation Options*. (November 2005). Electronically published by OPA as Supply Mix, Volume 4, Part 4: http://www.powerauthority.on.ca/Storage/25/2082_Part_4.4_SENES_Updated_Final_Report_(November).pdf

- applying data (raw and/or modified) for environmental categories to the supply and transmission resources developed for the IPSP according to electricity generated by each resource and the estimated transmission infrastructure requirements of the plan
- describing the environmental performance of the IPSP according to the environmental categories, as well as any alternatives to the plan and/or the current system mix
- evaluating subsequent iterations of the plan and subsequent IPSPs moving forward, to measure and track environmental performance.

Step One: Collecting Environmental Data

The work to collect and summarize a set of environmental performance data was started during the supply mix advice for generation options and has continued for the IPSP to include transmission infrastructure. This step involves compiling data for various air and greenhouse gas emissions, water use, and waste production for the construction and operation of generation technologies and transmission lines. For generation, these are expressed on a common scale - per unit electricity output (e.g., kg/MWh), with the exception of land use which is expressed per megawatt capacity (e.g., km^2/MW). Transmission line effects, primarily related to land use, are expressed in area (km^2) reflecting the product of the unit length of line and right-of-way width.

The usefulness of adopting the above approach is twofold. First, the environmental implication of energy projects have been studied and reported extensively. For the supply mix and the IPSP, the OPA commissioned SENES to conduct the research necessary to compile a credible and reasonably complete set of environmental performance data. Second, expressing the data according to a common unit lends the subsequent analysis robustness and flexibility, because resources can be added, subtracted or modified in the IPSP supply mix while maintaining the integrity of the analytical framework.

Step Two: Aggregating Environmental Data

Completing the first step results in a lot of data, and in some cases, it makes sense to aggregate multiple emissions into common indices. For each generating technology for example, step one can include various kinds of conventional air emissions, greenhouse gases and radiological air emissions. Attempting to make meaningful use of these data to guide decisions, trade-offs and mitigation strategies would be impractical without some means of simplifying their presentation. To do this, the data are aggregated together into indices according to environmental categories that are known to be associated with particular effects. For example, air emissions that are known to have ecosystem and human health effects are aggregated into an index for "conventional contaminant air emissions" and the primary greenhouse gases are aggregated into an index for indicating "global warming potential." For the conventional contaminant air emissions, each emission is normalized and added to an aggregate total wherein more weight is given to contaminants with known greater health impacts. These weightings are extrapolated from established ambient air quality standards. As such, a lower standard denotes a higher weight in the aggregate index. For greenhouse gas emissions, those gases with a higher global warming potential are given a higher weighting (e.g., methane is 23 times more powerful a greenhouse gas than carbon dioxide). Where weightings are used for aggregating the environmental data into environmental categories, they are explained in the subsequent section, “Environmental Performance Indicators and Assumptions”.

Step Three: Site and Technology Specification Using Modifiers

Most of the work in completing steps one and two was developed for the supply mix and updated for the IPSP work. The work previous to the IPSP was more generic because site specific information was not available for the supply mix advice. The development of the IPSP involves more site and technology specific considerations because the integrated plan is expected to support decisions regarding the types and location of system resources. This stage involves stating the operating assumptions of particular generation options under evaluation clearly. For example, this could include factors such the technologies employed, capacity factors, or when the information is available, energy production data.

The use of modifiers, applied to the environmental categories, enables the analysis to account for the higher probability of adverse or irreversible impacts associated with some environmental stressors – including, for example, where air emissions occur near populations or where the use of water affects more sensitive watersheds.

Modifiers were developed by SENES, based primarily on experience and professional judgment. These modifiers are subjective in nature and caution has been used in their application.

Step Four: Application to the IPSP at the Plan Level

This part of the methodology is where the data is applied to a mix of supply, transmission and CDM resources to represent the potential of the resource mix to cause environmental impacts. The IPSP resource mix will be characterized by capacities (MW) and estimated energy production (MWh) for the set of generation technologies comprising the system. Also part of the IPSP resources will be a certain amount of new transmission lines built (km), as well as expected CDM resources. The environmental implications of CDM resources, including conservation, energy efficiency, time of use pricing, demand response, fuel switching, cogeneration and small-scale renewables, may also be included in the methodology. For the time being, however, until more detail becomes available, no environmental impact potential has been assessed for CDM resources.

The methodology provides an estimate for each environmental criterion on a per year basis for each generation and transmission option identified in the IPSP (the "resource mix"). For each environmental criterion, the factors identified in step one are applied to the annual energy production of each generation resource, for air, water and waste, and to the installed capacity for land use. As an example, the appropriate normalized contaminant emission factor (in kg/MWh) is applied to the expected annual energy output (in MWh/yr) for the generating stations in the resource mix. The result in this example would be a value for conventional air emissions each generation type (e.g., wind, nuclear, etc.) in kilograms per year. Similarly, for transmission, the values associated with environmental performance are applied to the length of lines in km (multiplied by area of the rights-of-way) to produce a total value for environmental performance of that specific transmission mix. Land use is expressed in terms of area (km^2), but represents the total cumulative area over the course of the plan, rather than an annual rate. The modifiers described in step three can then be applied to each identified generation site and transmission line route to reflect site specific conditions.

The result of the analysis is a table of values that indicates the IPSP's performance in each environmental category. These values are expressed in absolute values (such as kg/year), permitting comparisons among generation sources and comparisons with future resource mixes (step five).

While there will be challenges associated with mitigating the total impacts of the IPSP due to the increase in the total capacity of the system, this approach enables the assessment of specific changes to the IPSP, and identifies the areas of concern related to the environment and sustainability of the plan.

Step Five: Results and Comparison

Once the results of the environmental categories for the IPSP resources are estimated in step four, the process is repeated for the current system, to which the IPSP will be compared in order to evaluate performance relative to baseline figures. This step is important to determine the direction that the future power system is headed in terms of environmental performance in each impact category.

Step Six: Iteration

This step involves both the development of the first IPSP and the consideration of sustainability in the future. Future IPSP's may include different resources than are considered today, environmental data may become more refined and more specific to the Ontario context, or planning assumptions may be refined and changed. The method of analysis is a framework that allows for evaluating categories that may be added, subtracted or refined. Iteration is an integral part of the integrated planning process that, in itself, is flexible and adaptable. For the sustainability assessment methodology to be useful, it must retain enough flexibility to adapt to new information and assumptions. The OPA believes that the approach described above has the required flexibility to meet the need for adequately considering sustainability in developing the first and subsequent IPSPs.

Environmental Performance Indicators and Assumptions

The following sections describe the environmental performance indicators, which include air and waste emissions, water use and land use requirements of generation and transmission resources. The data for the indicators is based on a number of sources reported in the 2005 SENES report completed for the supply mix advice. The data have been updated for the application to the IPSP and focus on the environmental performance of the construction and operation of the resources.

Also described in this section are the modifiers that have been developed for the IPSP analysis. The modifiers are included for the purpose of the discussion, but have not yet been applied to the analysis of the IPSP supply mix.

Air-Based Environmental Data

Air is considered an important environmental indicator for every generation option except renewable sources such as wind and photovoltaic (PV). Since impacts on air are generally a result of ongoing operations, emissions per megawatt hour is an appropriate metric. As defined in the 2005 report (SENES, 2005) air impacts from generation options are divided into three sub-indicators: greenhouse gas emissions, conventional contaminants and radioactivity.

Greenhouse Gas Emissions

Greenhouse gas (GHG) emissions are compared in kilograms of carbon dioxide equivalents (kg $CO_{2\ eq.}$) per megawatt hour. When aggregated for the entire electricity system, it is more appropriate to express GHGs in tonnes. This indicator includes three primary greenhouse gas emissions: carbon dioxide, methane and nitrous oxide (CO_2, CH_4 and N_2O respectively), weighted according to their global warming potential. Future risks posed by rising GHG emissions are of great interest and it is considered important to include them in a comparative evaluation of alternative energy technologies.

Greenhouse gas emissions are normalized according to the global warming potential of each constituent: CO_2 has a global warming potential of 1; CH_4 is 23; and N_2O is 296. The normalized GHG emissions are summarized for generation resources in Table 9.1

Table 9.1 – Normalized Greenhouse Gas Emissions

Technology	Emissions (kg $CO_{2\ eq.}$/MWh)
Hydroelectric (baseload)	20
Hydroelectric (peaking, imports and pumped storage)	33
Wind	10
Nuclear (new and refurbished)	12
Gas combined heat and power (CHP)	250
Combined cycle gas turbine (CCGT)	340
Single cycle gas turbine (SCGT)	570
Coal gasification (IGCC) with CO2 removal	77
Pulverized Coal	870
Biomass (without carbon credits)	93
Solar photovoltaic (PV)	130

Notes: Biomass emissions have potential to be carbon neutral.
Source: SENES

Conventional Contaminant Air Emissions

Contaminant air emissions are compared in kilograms per megawatt hour (kg/MWh), but the emissions rates of most of the individual contaminants are weighted to reflect their potential to cause adverse human health or ecological impacts. This indicator includes emissions of nitrous oxides (NO_x), sulphur dioxide (SO_2), particulate matter ($PM_{2.5}$), and select hazardous air pollutants (HAPs) with weighting appropriate to potential human health effects. Information for HAPs is not available for every generation option. The HAPs include mercury, formaldehyde and/or benzene.

The air emissions considered as conventional contaminants are routinely associated with the construction and operation of power generation activities. The contaminants have known effects on human health, ecosystems and the built environment. The known effects of the conventional contaminants are summarized in Table 9.2.

Table 9.2 – Summary of Effects of Conventional Contaminants

Contaminant	Impact Description	Effects
NO_x, SO_2, and $PM_{2.5}$	Human health	Reduction in life expectancy Smog
$PM_{2.5}$	Human health	Respiratory ailments Chronic bronchitis, coughing Asthma
NO_x, SO_2	Crops	Change in yields
	Ecosystems	Acidity and eutrophication
	Built environment	Damage to structures, ageing
Benzene, formaldehyde	Human health	Cancer risk
Mercury	Human health	Autoimmune effects
	Ecosystems	Bioaccumulation and biomagnification

Notes: $PM_{2.5}$ includes particles with an aerodynamic diameter < 2.5 μm, including secondary particles (sulphate and nitrate aerosols). These particles are considered "respirable" because they are small enough to enter the alveoli of the lungs.
Sources: ExternE, US Environmental Protection Agency

To normalize the pollutants emissions, weighting factors were developed based on ambient air quality standards for reference concentrations for each contaminant. Available annual average human health based air quality standards are used for the acid gases and particulate matter. Weightings are assigned based in the references in Table 9.3.

Table 9.3 – Determination of Weighting Factors for Air Contaminant Emissions

Contaminant	Reference	Value	Weighting Factor
NO_x	Environment Canada Maximum Acceptable Level (National Air Quality Objectives)	100 $\mu g/m^3$	1
SO_2	Ontario MOE Annual Ambient Air Quality Criteria	55 $\mu g/m^3$	1.8
$PM_{2.5}$	U.S. EPA National Ambient Air Quality Standards	15 $\mu g/m^3$	6.7
Benzene	U.S. EPA Integrated Risk Information System (IRIS) $1x10^{-5}$ risk level for inhalation	1.3 $\mu g/m^3$	77
Formaldehyde	U.S. EPA IRIS $1x10^{-5}$ risk level for inhalation	0.8 $\mu g/m^3$	125
Mercury	U.S. EPA IRIS inhalation reference concentration	0.3 $\mu g/m^3$	333

Sources: Environment Canada, Ontario Ministry of the Environment, US Environmental Protection Agency

The weighted emission rates are summed for each fuel/technology combination to determine a "normalized" emission value that can be used to compare different technologies. The resultant normalized contaminant air emissions are summarized for generation resources in Table 9.4.

Table 9.4 – Conventional Contaminant Air Emissions

Technology	NO_x	SO_2	$PM_{2.5}$	Benzene[3]	Formaldehyde	Mercury	Norm.[4]
Hydroelectric[2]	0.029	0.041	0.003				0.07
Wind	0.042	0.06	0.02				0.15
Nuclear Refurb.	0.25	0.01	0.01				0.39
Nuclear New	0.19	0.01	0.01				0.29
Gas CHP	0.22	0.01	0.01		0.002		0.53
CCGT	0.31	0.01	0.015		0.002		0.74
SCGT	0.51	0.02	0.02		0.004		1.23
Coal IGCC	0.49	0.61					1.61
Pulverized Coal	0.40	0.70	0.01	0.00002	0.00025	0.00005	1.85
Biomass	0.22	0.07	0.02				0.57
Solar PV	0.119	0.096	0.022				0.52

Notes:
1. Numbers expressed as kg/MWh.
2. Identical values for hydroelectric baseload, peaking, imports and pumped storage.
3. Blank spaces indicate data that has not been made available.
4. "Norm." column is the normalized index after application of weighting factors to individual emissions. Caution should be applied when communicating the normalized emission factor according to the unit of kg/MWh (normalizing emissions has the effect of inflating the emissions rate).
Source: SENES

Radioactivity

The indicator for radioactive air emissions considers radiological effects on local populations. Radioactive air emissions are compared as a normalized collective effective dose in (person Sieverts per gigawatt-annum).

Various radionuclides are released from nuclear construction and operation activities. The radionuclides released from nuclear reactors vary by type of reactor and from reactor to reactor but include such species as noble gases, radioactive particulate and tritium. Well accepted methods exist for converting exposure to any radionuclide to a common unit, namely dose (see for example UNSCEAR 2000, ICRP 60 1990). Radioactive emissions and normalized collective doses from the nuclear fuel cycle are reported by UNSCEAR 2000, and UNSCEAR 1993. The normalized radiological air emissions for three generation resources are summarized in Table 9.5. Radiological emissions to the air are assumed to be negligible for other generation resources.

Table 9.5 – Normalized Radiological Air Emissions

Technology	Dose (person Sv/GWa)
Nuclear	2.42
Gas	0.03
Coal	0.50

Source: SENES

Air-Based Environmental Impact Modifiers

Air Shed Modifier: With site-specific information, it is important to recognize and account for the potential for cumulative impacts on air sheds from the addition of generation options. The intention of this modifier is to identify areas where cumulative impacts are likely and where the addition of emissions to the immediate air shed is more likely to cause additional impact to human and terrestrial biology. The air shed modifiers are applied to the conventional contaminant and radiological air emissions. No modifiers are applied to the greenhouse gas emissions due to the global nature of climate change effects. Table 9.6 shows the categories and definitions for four levels of air shed impact.

Table 9.6 – Modifier Categories and Multipliers for Air Sheds

Category	Definition	Multiplier
1	Highly impacted air shed with multiple industrial and non-industrial emissions sources	2.0
2	Moderately impacted air shed with little industrial and non-industrial emissions sources	1.5
3	Lowly impacted air shed with no industrial and non-industrial emissions sources	1.25
4	Air shed is currently not undergoing direct pressure from industry or other non-industrial emissions	1.0

Source: SENES

For the purposes of this modifier, terms in Table 9.6 are defined as follows.

Industrial emissions: All air emissions that can be attributed to manufacturing, resource extraction or related activities such as mining, construction and the making of goods.

Non-industrial emissions: All air emissions that are a result of human activities such as those from transportation

Water-based Environmental Data

Water Use

This indicator is intended to capture the use, both consumptive and non-consumptive, of water by a generation option. Since impacts are a direct result of operations, cubic metres per megawatt hour is the appropriate metric. There are two general water use impacts: impacts resulting from use and consumption associated with the withdrawal of water and impacts that result from changes to the instream availability of water such as changes in water elevation or flow rates. Due to the fact that a large portion of the water used by a generation option may be returned to the water body from which it is drawn, it is important to distinguish between the amount that is withdrawn and the amount that is not returned (consumed). Both numbers are presented as cubic metres per megawatt hour of power generated. This indicator includes not only use but, potential effects on aquatic biology and changes to physical characteristics such as temperature and dissolved oxygen. Water usage characteristics for applicable generation resources are presented in Table 9.7. Water use associated with other resources is assumed to be negligible. Coal plants are excluded from the analysis at 2027.

Table 9.7 – Water Usage Characteristics

Technology[2]	Withdrawal	Consumption[3]
Hydroelectric Micro (0-10 MW)	50,250	
Hydroelectric Small (10-100 MW)	27,700	
Hydroelectric Medium (100-200 MW)	15,700	
Hydroelectric Large (200+ MW)	11,900	
Nuclear (refurbished and new)	228	1.5
Gas (all types)	76	0.4
Biomass	2.2	1.8

Notes:
1. Expressed as m^3/MWh.
2. Hydroelectric values include baseload, peaking, imports and pumped storage.
3. Blank spaces indicate negligible water consumption or consumption that has not been estimated.
Source: SENES

Water Use Modifiers

The supply mix advice contained two water use modifiers: one to account for the presence of fish and one intended to account for chemical or physical changes to water quality. Only the former was applied in the supply mix advice. The preliminary assessment of the IPSP retains both modifiers, with changed values to reflect the more site specific information that is available.

Presence of Aquatic Biota Modifier: In the supply mix advice this modifier simply assessed the presence, or absence, of fish in any water body that would be impacted by a generation option. As such, a multiplier of one was applied to all water use impacts. For the IPSP, it is assumed that all generation options that have water use impacts will affect water bodies that contain fish or other aquatic organisms. As such, this redefined modifier is intended to be more site-specific and assess the potential of physical impacts to aquatic biology, primarily through the potential for entrainment or impingement of organisms.

Table 9.8 presents the categories and definition for this modifier.

Table 9.8 – Modifier Categories and Multipliers for Presence of Aquatic Biota

Category	Definition	Multiplier
1	High potential for entrainment of aquatic biota High potential for impingement of aquatic biota	2.0
2	Moderate potential for entrainment of aquatic biota Moderate potential for impingement of aquatic biota	1.5
3	Low potential for entrainment of aquatic biota Low potential for impingement of aquatic biota	1.25
4	No potential for entrainment of aquatic biota No potential for impingement of aquatic biota	1.0

Source: SENES

For the purposes of this modifier, the terms used in Table 9.8 are defined as follows.

Entrainment: The drawing of fish and other aquatic organisms through a generation station, for example, by a hydroelectric generating station's turbine or a nuclear station's once through cooling water system.

Impingement: Trapping of aquatic organisms (usually fish) on generation station water intake screens.

The assumption is made that both entrainment and impingement result in the direct loss of the associated aquatic biology.

Changes to Water Quality Modifier: The intention of this modifier is to account for potentially harmful changes to the water quality through changes such as temperature, dissolved oxygen or the addition of a chemical component. In order to estimate the potential impacts of changes in the water quality, it is important to recognize that the potential impacts are biological and, in some cases, cumulative. Therefore, the impacts of a change in temperature, while potentially benign, may become lethal if combined with changes in dissolved oxygen or through the addition of chemical components. However, it must also be recognized that water discharge, with respect to quality, is closely regulated by both Environment Canada and the Ontario Ministry of Natural Resources. As such, any potentially harmful discharges will require permitting that will be site specific. For this reason, this modifier was not applied in the supply mix advice. However, because more site specific information is available for this report, three categories of potential impact have been defined and are presented in Table 9.9.

Table 9.9 – Modifier Categories and Multipliers for Changes to Water Quality

Category	Definition	Multiplier
1	Some potential for changes to physical water quality Some potential for changes to chemical water quality	2.0
2	Little potential for changes to physical water quality Little potential for changes to chemical water quality	1.5
3	No potential for changes to physical water quality No potential for change to chemical water quality	1.0

Source: SENES

For the purposes of this modifier, the terms used in Table 9.9 are defined as follows.

Physical water quality: Includes physical characteristics of water such as temperature, turbidity and dissolved oxygen.

Chemical water quality: Alteration of water quality through the addition of chemical substances such as contaminants like flocculants, pesticides and herbicides.

Land-Based Environmental Data

Land Use

This indicator is intended to provide a measurement of the amount of land used by a particular generation option per megawatt. This factor is considered important for all generation options with the exception of solar PV, which is assumed for this analysis, to be located on existing buildings. The land use calculation reflects the facility footprint or the area required for the facility and associated components (i.e., inside the fence). Land impacts are a function of the construction and ongoing presence of the facility and therefore area per megawatt, not per megawatt hour, is the appropriate metric. The loss of land will be quantitatively evaluated while the quality of the original land and the permanence of the loss are evaluated more qualitatively. Land use requirements for generation and transmission resources are presented in Table 9.10.

Table 9.10 – Land Use Requirements for Generation and Transmission

Technology	Land Use Requirement (km^2/MW or km)
Hydroelectric baseload	0.01
Hydroelectric peaking	0.19
Hydroelectric pumped storage	0.25
Manitoba import	0.04
Quebec import	1.1
Wind	0.32
Nuclear	0.0014
Gas	0.00025
Coal (pulverized and IGCC)	0.0067
Biomass	0.014
Solar PV	0
Transmission (km^2/km)	0.035

Source: SENES

Land Use Modifiers

The supply mix advice contained two land modifiers, only one of which, the "permanence of land impacted", was applied to the data in that report. The analysis of the IPSP will apply the two modifiers, both of which are based on those found in the 2005 report. However, the categories for these modifiers have been adjusted to more accurately reflect information that will be available for evaluating generation options and transmission in this report.

Species at risk and productive forest data used in determining the category were obtained from the Canada Atlas website (Natural Resources Canada 2006). Data for environmentally sensitive areas (ESAs), conservation areas and parks were obtained from the atlas as well as the Ontario Ministry of Natural Resources.

With respect to transmission, the scope of land impacts for a transmission line depends on both the length of the line and the nature of the land it covers; thus, each new line will have specific values.

Quality of Land Impacted or Lost Modifier: This modifier is intended to account for the quality of the land that will be impacted or lost by the development of a generation or transmission option. It is recognized that the construction and operation of electrical generation and transmission facilities, wherever located, will cause some changes to the natural environment. However, all aspects of the environment are not altered in the same manner, in the same physical space, or over the same time frame. The nature and the significance of the change vary according to the type of facilities installed, the methods of construction followed, the mitigation measures applied, and ongoing operational activities undertaken.

Land use quality acknowledges that certain components of the natural environment are worthy of greater protection than others. The four categories reflect the relative value of the environmental components, expressed through their pattern of distribution, the extent of their coverage (percentage occurrence), and/or their general location within study areas. These categories and associated multipliers are presented in Table 9.11.

Table 9.11 – Modifier Categories and Multipliers for Land Use Quality

Category	Definition	Multiplier
1	Aboriginal reserves National and Provincial Parks and Conservation Authority areas Areas with 32 to 95 designated species at risk Large lakes (excepting wind power options) Land previously inaccessible or rarely accessed by humans including lands that are not currently fragmented by roads or other linear features Provincially significant or sensitive biological areas (ANSIs, ESAs, etc.)	2.0
2	Lands in specialty crop production, including field vegetables, orchards and berries, lands with Canada Land Inventory (CLI) agricultural soil capability classes 1-4 for common field crops in row or mixed agricultural land use systems, and agricultural lands with tile drainage Areas with 76-98 % productive forest lands Areas with 16 to 32 designated species at risk Regionally or locally significant or sensitive ESAs and wetlands with capability classes 1-3	1.5
3	Urban areas having populations less than 500 and areas designated and zoned for development Existing cottage areas along waterways or smaller lakes with high recreational use Areas with 51-75 % productive forest lands Areas with 1 to 15 designated species at risk	1.25
4	All remaining forest lands Lands with CLI agricultural soil capability classes 1-4 for common field crops in hay or pasture	1.0

Source: SENES

Species at risk and productive forest data used in determining the category were obtained from the Canada Atlas website (Natural Resources Canada 2006). Data for ESAs, conservation areas and parks were obtained from the Atlas as well as MNR (2006)

Permanence of Land Impact Modifier: This modifier is intended to account for the potential for land impact to be non-permanent or accommodating of other land uses. Some of the generation and transmission facilities can coexist with other land use activities. For example, although a relatively large area is required for a wind farm, land between the turbines can still be utilized for animal grazing or crop production. Reservoirs created by hydroelectric stations can provide passive recreational uses such as boating and fishing.

When assessing the category that a given generation or transmission option falls into, application of one element in the definition will result in the application of that category. For example, although a wind farm may be seen to provide for many alternative uses such as farming or even recreation, if the wind farm is placed in an area where land is already heavily impacted, such as an urban setting, the highest multiplier would be applied.

Table 9.12 provides the four categories defined for the permanence of land impact modifier.

Table 9.12 – Modifier Categories and Multipliers for Permanence of Land Impact

Category	Definition	Multiplier
1	High direct and/or indirect effect on surrounding land High probability of cumulative effect Complete loss of all land, does not allow for alternative uses Irreversible effect on land	1.5
2	Moderate direct and/or indirect effect Moderate probability of cumulative effect Widespread extent of effect, allows for minor or few alternative uses Few mitigation measures available	1.25
3	Low direct and/or indirect effect Low probability of cumulative effect Low probability of equitable distribution of effect Localized extent of effect, allows for some alternative uses Nearly complete mitigation of effects on site	1.0
4	No direct and/or indirect effect No indirect effect No probability of cumulative effect Highly localized extent of effect, allows for alternative uses Complete mitigation of effects on site	0.75

Source: SENES

For the purposes of this modifier, the terms used in Table 9.12 are defined as follows.

Direct effect: The anticipated immediate and measurable physical and/or perceptual changes to the natural environment, specifically terrestrial land and its inhabitants, that are directly attributable to, or caused by, the construction and/or operation of generation or transmission facilities. An example would be the loss or alteration of land that falls within the fence-line of any generation option or transmission facility.

Indirect effect: Anticipated secondary changes to natural processes operating, or tertiary effect(s) on ecosystems or communities, that might occur on- or off-site, resulting from direct physical and/or perceptual changes to the natural environment, specifically terrestrial land and its inhabitants, caused by the construction and/or operation of generation or transmission facilities. An example would be any corridor effects on vegetation or terrestrial biota from transmission lines through forested areas.

Probability of cumulative effect: The sum of new impacts from generation options or transmission to past, present, and proposed future land impacts. This includes consideration of synergy of possible effects and reactions which could not otherwise be achieved by any one of the project actions alone, and of interactions resulting from the "piggy-backing" of effects from one project with others in a given area. The effects may either be greater or lesser than the simple additive effects. An example would be the use of land that was previously inaccessible or rarely accessed for either a generation station or transmission resulting in new access routes and increased pressure.

Extent of effect/potential for alternative uses: Identifies whether the loss of land will be confined to the immediate area or wide spread, a functional relationship between an expected project activity and the spatial distribution of the resulting environmental disturbance. An example would be thermal or nuclear generation stations where the fence-line area includes a large portion that will remain undisturbed forested or vegetated land.

Potential for mitigation of effects: Ability of construction and operation impacts to be reduced through measures beyond best management practices. An example would be the improvement of surrounding land that is either within the fence-line or in the immediate off-site area such as through planting.

Wastes Generated

Waste impacts are reported as kilograms produced annually per megawatt hour. This indicator is intended to include wastes generated during station operation, but not wastes from decommissioning of facilities. Since waste impacts directly result from operations, production per megawatt hour is an appropriate metric. Also, conventional solid or chemical wastes such as cans, cardboard, paper, newspaper, plastic, metals and glass, office or cleaning products are not factored into this model as they are common to all generation stations. The wastes generated for three generation resources are presented in Table 9.13.

Table 9.13 – Wastes Generated by Supply Options

Technology	Wastes Generated[1] (kg/MWh)
Nuclear[2]	0.0752
Biomass	0.011
Coal[3]	323

Notes:
1. Waste values do not differentiate between wastes with high-, medium- and low-level toxicity.
2. Approximately 10% of wastes produced by nuclear facilities are high-level radioactive wastes.
3. A small percentage of wastes produced by coal facilities is toxic. The majority of coal wastes can be diverted to some use, such as incorporation into building and construction materials.

Source: SENES

Waste Impacts Modifiers

The SENES 2005 report contained three waste modifiers, none of which were applied to the data collected for that report. For the purposes of this report, the permanence modifier is retained while the engineering cost and potential for environmental or human health impacts modifiers are not. The engineering cost modifier is not applied because social costs remain outside the scope of this analysis, as does the potential for environmental or human health impacts. Another modifier, however, has been developed for inclusion in this analysis that considers the potential for recycling of waste produced during the operation of a generation station.

Permanence of Waste Storage Facility Modifier: The intention of this modifier is to consider the permanence of a landfill facility or a long term storage facility. Wastes generated will either be disposed in a landfill (ash, gypsum), or stored in a long term waste facility (used radioactive fuel bundles and low and intermediate radioactive wastes).

However, from a land use perspective, both an engineered landfill and an intermediate or long-term storage facility for radioactive materials, can impair land use over the long-term. A closed landfill site can be vegetated to provide wildlife habitat, as can the land above the below ground storage facility and its associated above-ground building. It is not possible to distinguish between the permanency of the two waste disposal facilities and no modifying factor will be applied.

Potential for Waste Recycling Modifier: In the supply mix advice, as well as in the current assessment, only waste that was not recycled was counted in the tally for impacts per megawatt hour. However, for some generation options, the potential for recycling exists once a market for the waste has been established. Such is the case for biomass generation from wood waste where the ash produced during burning can be used as fertilizer if a market is available. Therefore, it is the intention of this modifier to reduce the impacts of waste because of the potential for recycling of that waste, despite the lack of a current market. Note that waste that is currently recycled will continue to be subtracted from the total tally.

Table 9.14 presents the modifier categories and multiplier values for the potential for waste recycling. At the current stage of this analysis, these modifiers have not yet been applied.

Table 9.14 – Modifier Categories and Multipliers for Waste

Category	Definition	Multiplier
1	No potential for recycling	1.0
2	Some potential for recycling	0.75
3	High potential for recycling	0.5

Source: SENES

For the purposes of this modifier, the terms used in Table 9.14 are defined as follows.

Recycling: This modifier accounts for any form of reuse of waste that diverts it from landfill or similar waste storage facility. This does include technology development that is currently underway and will be in use in the near future (less than 10 years).

Plan Level Environmental Performance Evaluation

The methodology for evaluating the environmental performance of different resource options is intended to be easily applied to different mixes of supply, transmission and CDM resources and to represent the best available information regarding the scale of environmental impacts. As shown in section 3.3 of this report, the information can be used to evaluate different supply mix options by applying the methodology to new resource assumptions and/or different locations. The information pertaining to the specific supply mix can be displayed with or without the use of the modifiers described in the preceding section. Without the use of modifiers, the results may be more representative of the actual emissions rates or land use requirements of the supply mix. Applying the modifiers adjusts the actual units to account for the site specificity of IPSP options.

The environmental indicators for which the evaluation was applied could be adapted to new technologies where impacts are expected to be similar. For example, all natural gas generating units with once-through cooling would roughly withdraw approximately 76 m^3 (76,000 litres) per MWh of water regardless of whether it was a new or old technology. Although the methodology can be adapted for any new generation option, emissions rates for some emissions, such as those to the air, will be specific to the new technology and, therefore, new rankings will likely need to be developed for additional resource assumptions.

The preliminary results of the environmental evaluation of the Preliminary Plan are presented in section 3.3 of this report.

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10. Appendix F: Numerical Data

This appendix provides the numerical data for a number of the figures appearing in this document.

Table 10.1 – Effective Resources (MW)

Effective Total	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Nuclear	11,514	11,514	11,514	10,764	10,764	11,514	10,998	9,966	9,116	7,750	7,750	5,270	3,540	2,660	1,265	1,265	1,265	1,265	1,265	1,265	750
Refurbished Nuclear	-	-	-	1,500	1,500	1,500	1,500	1,500	2,016	2,016	2,532	3,898	4,748	6,144	7,874	9,604	10,484	10,484	10,484	10,484	10,484
New Nuclear	-	-	-	-	-	-	-	-	-	-	-	700	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Existing Gas/Oil	4,539	4,539	4,539	4,539	4,539	4,539	4,539	4,539	4,539	4,539	4,539	4,539	4,539	4,539	4,539	4,539	4,539	4,539	4,539	4,539	4,539
New Gas	485	766	3,443	4,279	5,929	5,929	6,515	6,520	6,525	6,535	6,545	6,555	6,595	6,665	6,715	6,765	6,815	6,915	7,015	7,015	7,015
Existing Coal	6,434	6,434	6,434	6,434	4,969	2,987	2,987	2,987	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Renewables	6,078	6,079	6,079	6,079	6,079	6,079	6,079	6,079	6,079	6,079	6,079	6,079	6,079	6,079	6,079	6,079	6,079	6,079	6,079	6,079	6,079
New Renewables	57	189	400	833	920	1,121	1,166	1,310	1,959	3,543	3,626	3,730	4,359	3,029	3,110	3,110	3,111	3,181	3,181	3,281	3,282
CDM	322	785	1,315	1,545	1,811	2,038	2,236	2,407	2,611	2,831	3,074	3,281	3,510	3,756	4,026	4,318	4,633	4,973	5,310	5,706	6,134
New Storage	-	-	-	-	-	-	-	-	-	-	-	500	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
New Gasification	-	-	-	-	-	-	-	-	-	-	-	250	250	250	250	250	250	250	250	250	250
Interconnection	800	950	500	500	500	500	500	500	500	500	500	500	500	550	500	500	500	500	500	500	500
Total Effective	30,229	31,255	34,223	36,473	37,010	36,207	36,520	35,808	33,345	33,793	34,645	35,302	36,019	36,072	36,758	38,830	40,076	40,585	41,023	41,518	41,433

Source: OPA

Table 10.2 – Installed Resources (MW)

Installed Total	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Nuclear	11,514	11,514	11,514	10,764	10,764	11,514	10,998	9,966	9,116	7,750	7,750	5,270	3,540	2,660	1,265	1,265	1,265	1,265	1,265	1,265	750
Refurbished Nuclear	-	-	-	1,500	1,500	1,500	1,500	1,500	2,016	2,016	2,532	3,898	4,748	6,144	7,874	9,604	10,484	10,484	10,484	10,484	10,484
New Nuclear	-	-	-	-	-	-	-	-	-	-	-	700	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Existing Gas/Oil	5,064	5,064	5,064	5,064	5,064	5,064	5,064	5,064	5,064	5,064	5,064	5,064	5,064	5,064	5,064	5,064	5,064	5,064	5,064	5,064	5,064
New Gas	485	766	3,443	4,279	5,929	5,929	6,515	6,520	6,525	6,535	6,545	6,555	6,595	6,665	6,715	6,765	6,815	6,915	7,015	7,015	7,015
Existing Coal	6,434	6,434	6,434	6,434	4,969	2,987	2,987	2,987	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Renewables	8,137	8,137	8,137	8,137	8,137	8,137	8,137	8,137	8,137	8,137	8,137	8,137	8,137	8,137	8,137	8,137	8,137	8,137	8,137	8,137	8,137
New Renewables	139	461	1,276	2,280	2,412	2,795	2,911	3,105	4,151	6,090	6,531	7,113	8,451	7,556	7,637	7,638	7,639	7,733	7,734	7,870	7,871
CDM	322	785	1,315	1,545	1,811	2,038	2,236	2,407	2,611	2,831	3,074	3,281	3,510	3,756	4,026	4,318	4,633	4,973	5,310	5,706	6,134
New Storage	-	-	-	-	-	-	-	-	-	-	-	500	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
New Gasification	-	-	-	-	-	-	-	-	-	-	-	250	250	250	250	250	250	250	250	250	250
Interconnection	800	950	500	500	500	500	500	500	500	500	500	500	500	550	500	500	500	500	500	500	500
Total Installed	32,895	34,110	37,683	40,504	41,085	40,464	40,848	40,185	38,120	38,923	40,132	41,268	42,695	43,182	43,868	45,940	47,186	47,721	48,160	48,691	48,606

Source: OPA

Table 10.3 – Effective Resources by Fuel (MW)

Effective Total by Fuel	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CDM	322	785	1,315	1,545	1,811	2,038	2,236	2,407	2,611	2,831	3,074	3,281	3,510	3,756	4,026	4,318	4,633	4,973	5,310	5,706	6,134
Wind	67	97	214	319	319	337	350	350	419	491	563	660	766	854	854	854	854	854	854	854	854
Biomass	73	73	73	303	303	303	303	303	705	705	705	705	705	774	854	854	854	854	854	854	854
Solar	-	-	-	-	2	5	15	25	40	40	40	40	40	40	40	40	40	40	40	40	40
Hydro	5,995	6,098	6,192	6,290	6,375	6,555	6,578	6,712	6,875	8,387	8,398	8,404	8,927	7,439	7,440	7,441	7,442	7,511	7,512	7,611	7,612
Nuclear	11,514	11,514	11,514	12,264	12,264	13,014	12,498	11,466	11,132	9,766	10,282	9,868	9,688	10,204	10,539	12,269	13,149	13,149	13,149	13,149	12,634
Gas/Oil	5,024	5,304	7,981	8,818	10,468	10,468	11,054	11,059	11,064	11,074	11,084	11,094	11,134	11,204	11,254	11,304	11,354	11,454	11,554	11,554	11,554
Storage	-	-	-	-	-	-	-	-	-	-	-	500	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Coal	6,434	6,434	6,434	6,434	4,969	2,987	2,987	2,987	-	-	-	-	-	-	-	-	-	-	-	-	-
Gasification	-	-	-	-	-	-	-	-	-	-	-	250	250	250	250	250	250	250	250	250	250
Interconnection	800	950	500	500	500	500	500	500	500	500	500	500	500	550	500	500	500	500	500	500	500
Total Effective by Fuel	30,229	31,255	34,223	36,473	37,010	36,207	36,520	35,808	33,345	33,793	34,645	35,302	36,019	36,072	36,758	38,830	40,076	40,585	41,023	41,518	41,433

Source: OPA

Table 10.4 – Installed Resources by Fuel (MW)

Installed Total by Fuel	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CDM	322	785	1,315	1,545	1,811	2,038	2,236	2,407	2,611	2,831	3,074	3,281	3,510	3,756	4,026	4,318	4,633	4,973	5,310	5,706	6,134
Wind	395	571	1,260	1,877	1,877	1,981	2,056	2,056	2,462	2,885	3,311	3,885	4,507	5,025	5,025	5,025	5,025	5,025	5,025	5,025	5,025
Biomass	73	73	73	303	303	303	303	303	705	705	705	705	705	774	854	854	854	854	854	854	854
Solar	-	-	-	-	2	5	15	25	40	40	40	40	40	40	40	40	40	40	40	40	40
Hydro	7,808	7,954	8,080	8,237	8,367	8,643	8,675	8,858	9,081	10,598	10,612	10,621	11,337	9,854	9,855	9,856	9,857	9,952	9,953	10,089	10,090
Nuclear	11,514	11,514	11,514	12,264	12,264	13,014	12,498	11,466	11,132	9,766	10,282	9,868	9,688	10,204	10,539	12,269	13,149	13,149	13,149	13,149	12,634
Gas/Oil	5,549	5,829	8,506	9,343	10,993	10,993	11,579	11,584	11,589	11,599	11,609	11,619	11,659	11,729	11,779	11,829	11,879	11,979	12,079	12,079	12,079
Storage	-	-	-	-	-	-	-	-	-	-	-	500	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Coal	6,434	6,434	6,434	6,434	4,969	2,987	2,987	2,987	-	-	-	-	-	-	-	-	-	-	-	-	-
Gasification	-	-	-	-	-	-	-	-	-	-	-	250	250	250	250	250	250	250	250	250	250
Interconnection	800	950	500	500	500	500	500	500	500	500	500	500	500	550	500	500	500	500	500	500	500
Total Installed by Fuel	32,895	34,110	37,683	40,504	41,085	40,464	40,848	40,185	38,120	38,923	40,132	41,268	42,695	43,182	43,868	45,940	47,186	47,721	48,160	48,691	48,606

Source: OPA

Table 10.5 – Effective Resources by Aggregate Type (MW)

Aggregate Effective Total	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CDM	322	785	1,315	1,545	1,811	2,038	2,236	2,407	2,611	2,831	3,074	3,281	3,510	3,756	4,026	4,318	4,633	4,973	5,310	5,706	6,134
Renewables	6,135	6,268	6,479	6,912	6,999	7,200	7,245	7,389	8,038	9,622	9,705	9,809	10,438	9,108	9,189	9,189	9,190	9,260	9,260	9,360	9,361
Gas/Oil	5,024	5,304	7,981	8,818	10,468	10,468	11,054	11,059	11,064	11,074	11,084	11,094	11,134	11,204	11,254	11,304	11,354	11,454	11,554	11,554	11,554
Coal	6,434	6,434	6,434	6,434	4,969	2,987	2,987	2,987	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	11,514	11,514	11,514	12,264	12,264	13,014	12,498	11,466	11,132	9,766	10,282	9,868	9,688	10,204	10,539	12,269	13,149	13,149	13,149	13,149	12,634
Storage	-	-	-	-	-	-	-	-	-	-	-	500	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Gasification	-	-	-	-	-	-	-	-	-	-	-	250	250	250	250	250	250	250	250	250	250
Interconnection	800	950	500	500	500	500	500	500	500	500	500	500	500	550	500	500	500	500	500	500	500
Total Aggregate Effective	30,229	31,255	34,223	36,473	37,010	36,207	36,520	35,808	33,345	33,793	34,645	35,302	36,019	36,072	36,758	38,830	40,076	40,585	41,023	41,518	41,433

Corresponds to Figure 3.1 and Figure 3.6.
Source: OPA

Table 10.6 – Installed Resources by Aggregate Type (MW)

Aggregate Installed Total	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CDM	322	785	1,315	1,545	1,811	2,038	2,236	2,407	2,611	2,831	3,074	3,281	3,510	3,756	4,026	4,318	4,633	4,973	5,310	5,706	6,134
Renewables	8,276	8,598	9,414	10,418	10,549	10,932	11,049	11,242	12,288	14,228	14,668	15,250	16,589	15,693	15,774	15,775	15,776	15,871	15,872	16,008	16,009
Gas/Oil	5,549	5,829	8,506	9,343	10,993	10,993	11,579	11,584	11,589	11,599	11,609	11,619	11,659	11,729	11,779	11,829	11,879	11,979	12,079	12,079	12,079
Coal	6,434	6,434	6,434	6,434	4,969	2,987	2,987	2,987	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	11,514	11,514	11,514	12,264	12,264	13,014	12,498	11,466	11,132	9,766	10,282	9,868	9,688	10,204	10,539	12,269	13,149	13,149	13,149	13,149	12,634
Storage	-	-	-	-	-	-	-	-	-	-	-	500	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Gasification	-	-	-	-	-	-	-	-	-	-	-	250	250	250	250	250	250	250	250	250	250
Interconnection	800	950	500	500	500	500	500	500	500	500	500	500	500	550	500	500	500	500	500	500	500
Total Aggregate Installed	32,895	34,110	37,683	40,504	41,085	40,464	40,848	40,185	38,120	38,923	40,132	41,268	42,695	43,182	43,868	45,940	47,186	47,721	48,160	48,691	48,606

Corresponds to Figure 3.5
Source: OPA

Table 10.7 – Installed Resources as Percentage of Total Installed Resources

Aggregate Installed % of Total Installed	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CDM	1%	2%	3%	4%	4%	5%	5%	6%	7%	7%	8%	8%	8%	9%	9%	9%	10%	10%	11%	12%	13%
Renewables	25%	25%	25%	26%	26%	27%	27%	28%	32%	37%	37%	37%	39%	36%	36%	34%	33%	33%	33%	33%	33%
Gas/Oil	17%	17%	23%	23%	27%	27%	28%	29%	30%	30%	29%	28%	27%	27%	27%	26%	25%	25%	25%	25%	25%
Coal	20%	19%	17%	16%	12%	7%	7%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Nuclear	35%	34%	31%	30%	30%	32%	31%	29%	29%	25%	26%	24%	23%	24%	24%	27%	28%	28%	27%	27%	26%
Storage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%
Gasification	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Interconnection	2%	3%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Total	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Source: OPA

Table 10.8 – Effective Resources as Percentage of Total Effective Resources

Aggregate Effective % of Total Effective	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CDM	1%	3%	4%	4%	5%	6%	6%	7%	8%	8%	9%	9%	10%	10%	11%	11%	12%	12%	13%	14%	15%
Renewables	20%	20%	19%	19%	19%	20%	20%	21%	24%	28%	28%	28%	29%	25%	25%	24%	23%	23%	23%	23%	23%
Gas/Oil	17%	17%	23%	24%	28%	29%	30%	31%	33%	33%	32%	31%	31%	31%	31%	29%	28%	28%	28%	28%	28%
Coal	21%	21%	19%	18%	13%	8%	8%	8%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Nuclear	38%	37%	34%	34%	33%	36%	34%	32%	33%	29%	30%	28%	27%	28%	29%	32%	33%	32%	32%	32%	30%
Storage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	3%	3%	3%	2%	2%	2%	2%	2%
Gasification	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Interconnection	3%	3%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	2%	1%	1%	1%	1%	1%	1%	1%
Total	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Source: OPA

Table 10.9 – Installed Annual New Resources (MW)

New annual installed	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Refurbished Nuclear	-	-	-	1,500	-	-	-	-	516	-	516	1,366	850	1,396	1,730	1,730	880	-	-	-	-
New Nuclear	-	-	-	-	-	-	-	-	-	-	-	700	700	-	-	-	-	-	-	-	-
New Gas	485	281	2,677	836	1,650	-	586	5	5	10	10	10	40	70	50	50	50	100	100	-	-
New Renewables	139	322	815	1,004	132	383	117	193	1,046	1,940	440	583	1,338	604	81	1	1	95	1	136	1
CDM	322	462	530	231	265	228	198	171	204	220	243	207	229	247	270	291	315	340	338	396	428
New Storage	-	-	-	-	-	-	-	-	-	-	-	500	-	500	-	-	-	-	-	-	-
New Gasification	-	-	-	-	-	-	-	-	-	-	-	250	-	-	-	-	-	-	-	-	-
Total	946	1,065	4,022	3,571	2,047	610	900	369	1,771	2,170	1,209	3,616	3,157	2,817	2,131	2,072	1,246	535	439	532	429

Corresponds to Figure 3.2.
Source: OPA

Table 10.10 – Effective Annual New Resources (MW)

New annual effective	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Refurbished Nuclear	-	-	-	1,500	-	-	-	-	516	-	516	1,366	850	1,396	1,730	1,730	880	-	-	-	-
New Nuclear	-	-	-	-	-	-	-	-	-	-	-	700	700	-	-	-	-	-	-	-	-
New Gas	485	281	2,677	836	1,650	-	586	5	5	10	10	10	40	70	50	50	50	100	100	-	-
New Renewables	57	132	211	433	87	201	46	144	649	1,584	83	104	629	170	81	1	1	69	1	99	1
CDM	322	462	530	231	265	228	198	171	204	220	243	207	229	247	270	291	315	340	338	396	428
New Storage	-	-	-	-	-	-	-	-	-	-	-	500	-	500	-	-	-	-	-	-	-
New Gasification	-	-	-	-	-	-	-	-	-	-	-	250	-	-	-	-	-	-	-	-	-
Total	864	875	3,418	3,000	2,002	428	829	320	1,374	1,814	852	3,137	2,447	2,382	2,131	2,072	1,246	509	438	495	429

Source: OPA

Table 10.11 – Installed Cumulative New Resources (MW)

New cumulative installed	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Refurbished Nuclear	-	-	-	1,500	1,500	1,500	1,500	1,500	2,016	2,016	2,532	3,898	4,748	6,144	7,874	9,604	10,484	10,484	10,484	10,484	10,484
New Nuclear	-	-	-	-	-	-	-	-	-	-	-	700	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
New Gas	485	766	3,443	4,279	5,929	5,929	6,515	6,520	6,525	6,535	6,545	6,555	6,595	6,665	6,715	6,765	6,815	6,915	7,015	7,015	7,015
New Renewables	139	461	1,276	2,280	2,412	2,795	2,911	3,105	4,151	6,090	6,531	7,113	8,451	7,556	7,637	7,638	7,639	7,733	7,734	7,870	7,871
CDM	322	785	1,315	1,545	1,811	2,038	2,236	2,407	2,611	2,831	3,074	3,281	3,510	3,756	4,026	4,318	4,633	4,973	5,310	5,706	6,134
New Storage	-	-	-	-	-	-	-	-	-	-	-	500	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
New Gasification	-	-	-	-	-	-	-	-	-	-	-	250	250	250	250	250	250	250	250	250	250
Total	946	2,012	6,034	9,605	11,652	12,262	13,162	13,532	15,303	17,473	18,682	22,298	25,455	26,771	28,902	30,974	32,221	32,755	33,194	33,725	34,155

Corresponds to Figure 3.3.
Source: OPA

Table 10.12 – Effective Cumulative New Resources (MW)

New cumulative effective	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Refurbished Nuclear	-	-	-	1,500	1,500	1,500	1,500	1,500	2,016	2,016	2,532	3,898	4,748	6,144	7,874	9,604	10,484	10,484	10,484	10,484	10,484
New Nuclear	-	-	-	-	-	-	-	-	-	-	-	700	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
New Gas	485	766	3,443	4,279	5,929	5,929	6,515	6,520	6,525	6,535	6,545	6,555	6,595	6,665	6,715	6,765	6,815	6,915	7,015	7,015	7,015
New Renewables	57	189	400	833	920	1,121	1,166	1,310	1,959	3,543	3,626	3,730	4,359	3,029	3,110	3,110	3,111	3,181	3,181	3,281	3,282
CDM	322	785	1,315	1,545	1,811	2,038	2,236	2,407	2,611	2,831	3,074	3,281	3,510	3,756	4,026	4,318	4,633	4,973	5,310	5,706	6,134
New Storage	-	-	-	-	-	-	-	-	-	-	-	500	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
New Gasification	-	-	-	-	-	-	-	-	-	-	-	250	250	250	250	250	250	250	250	250	250
Total	864	1,740	5,158	8,158	10,160	10,588	11,417	11,737	13,111	14,925	15,777	18,915	21,362	22,244	24,375	26,447	27,693	28,202	28,641	29,136	29,565

Corresponds to Figure 3.4.
Source: OPA

Table 10.13 – Installed Cumulative New Renewables (MW)

Installed cumulative new renewables	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Water	44	190	316	473	603	879	911	1,094	1,317	1,334	1,348	1,357	2,073	2,090	2,091	2,092	2,093	2,188	2,189	2,325	2,326
Hydroelectric Purchase	-	-	-	-	-	-	-	-	-	1,500	1,500	1,500	1,500	-	-	-	-	-	-	-	-
Wind	90	266	955	1,572	1,572	1,676	1,751	1,751	2,157	2,580	3,006	3,580	4,202	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720
Biomass	5	5	5	235	235	235	235	235	637	637	637	637	637	706	786	786	786	786	786	786	786
Solar	-	-	-	-	2	5	15	25	40	40	40	40	40	40	40	40	40	40	40	40	40

Corresponds to Figure 2.13.
Source: OPA

Table 10.14 – Effective Cumulative New Renewables (MW)

Effective cumulative new renewables	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Water	37	139	233	331	416	596	619	753	916	928	939	945	1,468	1,480	1,481	1,482	1,483	1,552	1,553	1,652	1,653
Hydroelectric Purchase	-	-	-	-	-	-	-	-	-	1,500	1,500	1,500	1,500	-	-	-	-	-	-	-	-
Wind	15	45	162	267	267	285	298	298	367	439	511	609	714	802	802	802	802	802	802	802	802
Biomass	5	5	5	235	235	235	235	235	637	637	637	637	637	706	786	786	786	786	786	786	786
Solar	-	-	-	-	2	5	15	25	40	40	40	40	40	40	40	40	40	40	40	40	40

Corresponds to Figure 2.14.
Source: OPA

Table 10.15 – Installed Annual New Renewables (MW)

Installed annual new renewables	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Water	44	190	126	157	130	276	32	183	223	17	15	9	716		1	1	1	95	1	136	1
Hydroelectric Purchase	-	-	-	-	-	-	-	-	-	1,500	-	-	-	1,500	-	-	-	-	-	-	-
Wind	90	266	689	617	-	104	75	-	407	423	426	574	622	518	-	-	-	-	-	-	-
Biomass	5	5	-	230	-	-	-	-	402	-	-	-	-	70	80	-	-	-	-	-	-
Solar	-	-	-	-	2	3	10	10	15	-	-	-	-	-	-	-	-	-	-	-	-

Corresponds to Figure 2.10.
Source: OPA

Table 10.16 – Effective Annual New Renewables (MW)

Effective annual new renewables	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Water	37	139	94	98	85	180	23	134	163	12	11	6	523		1	1	1	69	1	99	1
Hydroelectric Purchase	-	-	-	-	-	-	-	-	-	1,500	-	-	-	- 1,500	-	-	-	-	-	-	-
Wind	15	45	117	105	-	18	13	-	69	72	72	98	106	88	-	-	-	-	-	-	-
Biomass	5	5	-	230	-	-	-	-	402	-	-	-	-	70	80	-	-	-	-	-	-
Solar	-	-	-	-	2	3	10	10	15	-	-	-	-	-	-	-	-	-	-	-	-

Corresponds to Figure 2.11.
Source: OPA

Table 10.17 – Installed Cumulative New Waterpower (MW)

Installed new waterpower	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Committed	-	23	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
Near Term	44	167	273	430	560	836	868	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051
Long Term	-	-	-	-	-	-	-	-	223	240	255	263	979	996	997	998	999	1,094	1,095	1,231	1,232
Total	44	190	316	473	603	879	911	1,094	1,317	1,334	1,348	1,357	2,073	2,090	2,091	2,092	2,093	2,188	2,189	2,325	2,326

Corresponds to Figure 2.6.
Source: OPA

Table 10.18 – Effective Existing versus New Resources (MW)

Effective existing vs. new	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Resources	28,564	28,565	28,565	27,815	26,350	25,118	24,602	23,570	19,733	18,367	18,367	15,887	14,157	13,277	11,882	11,882	11,882	11,882	11,882	11,882	11,367
New Resources	1,665	2,690	5,658	8,658	10,660	11,088	11,917	12,237	13,611	15,425	16,277	19,415	21,862	22,794	24,875	26,947	28,193	28,702	29,141	29,636	30,065
TOTAL	30,229	31,255	34,223	36,473	37,010	36,207	36,520	35,808	33,345	33,793	34,645	35,302	36,019	36,072	36,758	38,830	40,076	40,585	41,023	41,518	41,433

Source: OPA

Table 10.19 – Effective Existing versus Committed versus Other Resources (MW)

Effective existing vs. committed vs. other new	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Resources	28,564	28,565	28,565	27,815	26,350	25,118	24,602	23,570	19,733	18,367	18,367	15,887	14,157	13,277	11,882	11,882	11,882	11,882	11,882	11,882	11,367
Committed New Resources	834	1,637	4,432	6,768	6,768	6,768	6,768	6,768	6,768	6,768	6,768	6,768	6,768	6,768	6,768	6,768	6,768	6,768	6,768	6,768	6,768
Other New Resources	831	1,053	1,226	1,890	3,891	4,320	5,149	5,469	6,843	8,657	9,509	12,646	15,094	16,026	18,107	20,179	21,425	21,934	22,373	22,867	23,297
Total	30,229	31,255	34,223	36,473	37,010	36,207	36,520	35,808	33,345	33,793	34,645	35,302	36,019	36,072	36,758	38,830	40,076	40,585	41,023	41,518	41,433

Corresponds to Figure 1.3.
Source: OPA

Table 10.20 – Peak Demand, Reserve Requirement, Resource Requirement

Year	Annual Peak Demand (MW)	Required Reserve (%)	Required Reserve (MW)	Required Resources
2007	26,399	14.5%	3,828	30,227
2008	26,692	17%	4,538	31,230
2009	26,988	17%	4,588	31,576
2010	27,288	17%	4,639	31,927
2011	27,520	17%	4,678	32,199
2012	27,755	17%	4,718	32,473
2013	27,992	17%	4,759	32,750
2014	28,230	17%	4,799	33,029
2015	28,471	17%	4,840	33,311
2016	28,877	17%	4,909	33,787
2017	29,290	17%	4,979	34,269
2018	29,708	17%	5,050	34,758
2019	30,132	17%	5,122	35,254
2020	30,562	18.0%	5,501	36,063
2021	31,138	18.0%	5,605	36,742
2022	31,724	18.0%	5,710	37,435
2023	32,322	18.0%	5,818	38,140
2024	32,931	18.0%	5,928	38,859
2025	33,573	18.0%	6,043	39,616
2026	34,230	18.0%	6,161	40,391
2027	34,899	18.0%	6,282	41,181

Source: OPA

APPENDIX 7

Minister's June 13, 2006 Directive to OPA on IPSP Goals.

✓ C.C. Mary Ellen Richardson

Minister of Energy

Hearst Block, 4th Floor
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6715
Fax: 416-327-6754

Ministre de l'Énergie

Édifice Hearst, 4e étage
900, rue Bay
Toronto ON M7A 2E1
Tél.: 416-327-6715
Téléc.: 416-327-6754

Ontario

June 13, 2006

Dr. Jan Carr
Chief Executive Officer
Ontario Power Authority
1600-120 Adelaide Street West
Toronto, Ontario
M5H 1T1

Dear Dr. Carr:

Re: Integrated Power System Plan

As authorized by the Lieutenant Governor in Council under Section 25.30 of the *Electricity Act, 1998*, I am providing direction for the preparation of the Integrated Power System Plan.

The Government directs the OPA to create an Integrated Power System Plan to meet the following goals:

1. The goal for total peak demand reduction from conservation by 2025 is 6,300 MW. The plan should define programs and actions which aim to reduce projected peak demand by 1,350 MW by 2010, and by an additional 3,600 MW by 2025. The reductions of 1,350 MW and 3,600 MW are to be in addition to the 1,350 MW reduction set by the government as a target for achievement by 2007. The plan should assume conservation includes continued use by the government of vehicles such as energy efficiency standards under the *Energy Efficiency Act* and the Building Code, and should include load reduction from initiatives such as: geothermal heating and cooling; solar heating; fuel switching; small scale (10 MW or less) customer-based electricity generation, including small scale natural gas fired co-generation and tri-generation, and including generation encouraged by the recently finalized net metering regulation.

2. Increase Ontario's use of renewable energy such as hydroelectric, wind, solar, and biomass for electricity generation. The plan should assist the government in meeting its target for 2010 of increasing the installed capacity of new renewable

.../cont'd

energy sources by 2,700 MW from the 2003 base, and increase the total capacity of renewable energy sources used in Ontario to 15,700 MW by 2025.

3. Plan for nuclear capacity to meet base-load electricity requirements but limit the installed in-service capacity of nuclear power over the life of the plan to 14,000 MW.

4. Maintain the ability to use natural gas capacity at peak times and pursue applications that allow high efficiency and high value use of the fuel.

5. Plan for coal-fired generation in Ontario to be replaced by cleaner sources in the earliest practical time frame that ensures adequate generating capacity and electricity system reliability in Ontario.

   The OPA should work closely with the IESO to propose a schedule for the replacement of coal-fired generation, taking into account feasible in-service dates for replacement generation and necessary transmission infrastructure.

6. Strengthen the transmission system to:

   - Enable the achievement of the supply mix goals set out in this directive;
   - Facilitate the development and use of renewable energy resources such as wind power, hydroelectric power and biomass in parts of the province where the most significant development opportunities exist;
   - Promote system efficiency and congestion reduction and facilitate the integration of new supply, all in a manner consistent with the need to cost effectively maintain system reliability.

7. The plan should comply with Ontario Regulation 424/04 as revised from time to time.

Yours sincerely,

Dwight Duncan
Minister of Energy

APPENDIX 8

Minister's November 7, 2005 Directive to OPA on RES I contracts.

NOV 08 2005

Minister of Energy

Hearst Block, 4th Floor
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6715
Fax: 416-327-6754

Ministre de l'Énergie

Édifice Hearst, 4e étage
900, rue Bay
Toronto ON M7A 2E1
Tél.: 416-327-6715
Téléc.: 416-327-6754

Ontario

c.c. A. Shalaby
c.c. P. Bradley
c.c. P. Sherwill
c.c. M. Lyle

DIRECTION

Ontario Power Authority
Attention: Mr. Jan Carr, Chief Executive Officer

Re: Contracts Relating to the Request for Proposals for 300 Megawatts of Renewable Energy Supply Projects (the "RES I RFP") issued on June 24, 2004, as amended.

I write in connection with my authority as the Minister of Energy in order to exercise the statutory power of ministerial direction, which I have in respect of the Ontario Power Authority (the "OPA") under section 25.32 of the *Electricity Act, 1998* (the "Act").

On June 24, 2004, the Ministry of Energy issued a request for proposals for the procurement of 300 Megawatts of new electricity supply derived from renewable energy sources (the "RES 1 RFP"). This RES 1 RFP resulted in the execution, by the Ontario Electricity Financial Corporation (the "OEFC"), as an agent of the Crown, of the ten (10) contracts (the "Agreements") listed in the table below for projects which derive electricity from renewable energy sources including wind, hydro-electric, landfill and digester gas.

Pursuant to subsection 25.32(4) of the Act, I hereby direct the OPA to assume, by no later than November 10th, 2005, responsibility for exercising all powers and performing all duties of the Crown, including powers and duties to be exercised and performed through the OEFC, as an agent of the Crown, (as Buyer), in respect of the Agreements listed below:

RES I CONTRACTS

Item	Supplier	Date of Execution	Project	Location
1.	Superior Wind Energy Inc. (assigned to Superior Wind Prince Power Inc.)	November 24, 2004	Prince Phase I Wind Energy Project	District of Algoma, Township of Prince, Ontario.
2.	Erie Shores Wind Limited Partnership	November 24, 2004	Erie Shores Wind Farm	North Shore of Lake Erie in Norfolk and Elgin Counties, Ontario.
3.	Canadian Hydro Developers, Inc.	November 24, 2004	Melancthon - Grey Wind Project	Southern Portion of Melancthon Township, Ontario.
4.	Superior Wind Energy Inc. (assigned to Superior Wind Blue Highlands Power Inc)	November 24, 2004	Blue Highlands Phase I Wind Energy Project	Town of Blue Mountains, Grey County, Ontario.
5.	EPCOR Power Development Corporation	November 24, 2004	Kingsbridge Wind Power Project	Ashfield-Colborne-Wawanosh Township, Huron County, Ontario.
6.	Energy Ottawa Inc. (assigned to 2079051 Ontario Inc.)	November 24, 2004	Trail Road Landfill Gas Generating Station	Trail Waste Facility Landfill Site, 4775 Trail Road, Ottawa, Ontario

7.	1615151 Ontario Inc. (name changed to Ecotricity Guelph Inc.)	November 24, 2004	Eastview Landfill Gas Energy Plant	Eastview Landfill Site, Guelph, Ontario
8.	Hamilton Hydro Services Inc. (assigned to HamiltonHydro Energy Inc.)	December 23, 2004	Hamilton (Digester Gas) Cogeneration Project	Woodward Avenue Wastewater Treatment Plant, Hamilton, Ontario
9.	Umbata Falls, Limited Partnership	November 24, 2004	Umbata Falls Hydroelectric Project	Umbata Falls, White River, approximately 30 kilometres southeast of Marathon, Ontario
10.	Glen Miller Power, Limited Partnership	November 24, 2004	Glen Miller Hydroelectric Project	On the Trent River, at Lock # 3, Trenton, Ontario

Further, pursuant to my authority under section 25.32 of the Act, the OPA is also hereby authorized and directed to execute and deliver such agreements or ancillary documents, deeds and instruments in connection with, pertaining to, or arising out of, the assumption of the above-noted Agreements or to effect the assumption by the OPA of the above-noted Agreements.

This Direction shall be effective and binding as of the date hereof.

Dated: November 7th, 2005

Donna Cansfield

Donna Cansfield
Minister of Energy

APPENDIX 9

Minister's November 16, 2005 Directive to OPA on RES II contracts.

DIRECTION

Ontario Power Authority
Attention: Mr. Jan Carr, Chief Executive Officer

Re: Contracts Relating to the Request for Proposals for Up To 1,000 Megawatts of Renewable Energy Supply Projects with a Contract Capacity of between 20 MW and 200 MW, inclusive issued on June 17, 2005, as amended (the "RES II RFP")

I write in connection with my authority as the Minister of Energy in order to exercise the statutory power of ministerial direction, which I have in respect of the Ontario Power Authority (the "OPA") under section 25.32 of the *Electricity Act, 1998* (the "Act").

On June 17, 2005, the Ministry of Energy issued a request for proposals, as amended, for the procurement of up to 1,000 Megawatts of new electricity supply derived from renewable energy sources (the "RES II RFP"). Nine (9) proponents have been selected pursuant to this RES II RFP.

Pursuant to subsection 25.32(7) of the Act, I hereby direct the OPA to enter into contracts contemplated by the RES II RFP (the "RES II Contracts") with each of the suppliers set out in the following table:

RES II CONTRACTS

Item	Supplier	Project	Location
1.	Yellow Falls Limited Partnership	Island Falls Hydroelectric Project	Bradburn Township, near Smooth Rock Falls, Ontario
2.	Kruger Energy Port Alma Limited Partnership	Kruger Energy Port Alma	Municipality of Chatham Kent, near Port Alma, Ontario
3.	Enbridge Ontario Wind Power LP or Leader Wind Corp.	Leader Wind Power Project – A 100.65MW	Bruce County, Municipality of Kincardine & Town of Saugeen Shores, Town of Underwood, Ontario
4.	Enbridge Ontario Wind Power LP or Leader Wind Corp.	Leader Wind Power Project – B 99 MW	Bruce County, Municipality of Kincardine & Town of Saugeen Shores, Town of Underwood, Ontario
5.	Brascan Power Wind – Prince II, L.P.	Prince II Wind Power Project	Townships of Dennis, Pennefather, Korah and Aweres, near Algoma, Ontario
6.	EPCOR Power Development (Ontario) Limited Partnership	Kingsbridge II Wind Power Project	Ashfield Ward, Ashfield Colborne Wawanosh Township, Huron County, Ontario
7.	Suncor Energy Products Inc. and EHN Windpower Canada Inc.	Ripley Wind Power Project	Township of Huron-Kinloss near Ripley, Ontario
8.	Canadian Hydro Developers, Inc.	Melancthon II Wind Project	Melancthon and Amaranth Townships, near Shelburne, Ont.
9.	Canadian Renewable Energy Corporation	Wolfe Island Wind Project	Township of Frontenac Islands, near Kingston, Ontario

Further, pursuant to my authority under section 25.32 of the Act, the OPA is also hereby authorized and directed to execute and deliver such agreements or ancillary documents, deeds and instruments in connection with, pertaining to, or arising out of, the entering into of the above-noted contracts. This Direction shall be effective and binding as of the date hereof.

Dated: November 16th, 2005

Donna Cansfield

Donna Cansfield
Minister of Energy

APPENDIX 10

Schedule of OPA Contracts for Bruce Area Wind Projects under RES I and II.

Wind Generation in the Bruce Peninsula

Wind Generation Project	Procurement Process	Capacity (MW)
Melancthon I	RES I	67.5
Melancthon II	RES II	132.0
Kingsbridge I	RES I	39.6
Kingsbridge II	RES II	158.7
Leader A	RES II	100.7
Leader B	RES II	99.0
Ripley	RES II	76.0
Total		**673.5**

APPENDIX 11

Minister's March 21, 2006 Directive to OPA on Renewable Standard Offer Program

Minister of Energy

Hearst Block, 4th Floor
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6715
Fax: 416-327-6754

Ministre de l'Énergie

Édifice Hearst, 4e étage
900, rue Bay
Toronto ON M7A 2E1
Tél. 416-327-6715
Téléc.: 416-327-6754

Ontario

March 21, 2006

Mr. Jan Carr
Chief Executive Officer
Ontario Power Authority
1600-120 Adelaide Street West
Toronto, Ontario
M5H 1T1

Dear Mr. Carr:

Re: Standard Offer Program

I write in connection with my authority as Minister of Energy in order to exercise the statutory power of ministerial direction that I have in respect of the Ontario Power Authority (the "OPA") under section 25.32 of the *Electricity Act, 1998* (the "Act").

On December 10, 2004, the Ministry of Energy commenced an initiative relating to a Standard Offer Program for small generators by entering into a contract with the Ontario Sustainable Energy Association ("OSEA") to report on how to overcome the barriers to participating in Ontario's electricity supply sector for small renewable generators, including the consideration of a standard offer program for small generators.

In addition, I am aware that the OPA's stakeholder consultation process related to generation procurement that was carried out in the summer of 2005 also identified a Standard Offer Program as a mechanism to address procurement barriers for proponents of smaller projects.

Following these developments, by letter dated August 18, 2005, the Minister of Energy continued to pursue the Standard Offer Program initiative by requesting that the OPA and the Ontario Energy Board (the "OEB") work together to address the barriers to small generators through a Standard Offer Program. The letter specifically referenced OSEA's report as providing useful background information to consider in developing a Standard Offer Program. The Program was to reflect the costs and benefits of renewable energy as well as the government's stated objectives with respect to renewable energy. The OEB, in accordance with its authority, focused on the

.../cont'd

necessary changes to codes and connection requirements, and on ensuring non-discriminatory access to the electricity system. The OPA, in accordance with its authority to procure electricity supply and capacity, investigated the appropriate price and eligibility requirements for projects to qualify for the Standard Offer Program.

As per my request, I received the report of the OPA and the OEB on a proposed Standard Offer Program. Pursuant to section 25.32 of the *Electricity Act, 1998,* and with the objective of ensuring electricity supply through the completion of the Standard Offer Program initiative, I hereby direct the OPA to assume, effective as of the date of this letter of direction, responsibility for exercising the powers and performing the duties of the Crown under the Standard Offer Program initiative with the objective of having the Program in place by the fall of 2006. It is expected that, as a consequence of this direction, the OPA will enter into such contracts with small renewable generators as are necessary to implement the Program.

This Directive shall be effective and binding as of the date hereof.

Sincerely,

Donna Cansfield

Donna Cansfield
Minister

APPENDIX 12

Minister's October 14, 2005 Directive to OPA on Bruce Units 1 and 2 Refurbishment

DIRECTION

To: **Ontario Power Authority**
Attention: **Mr. Jan Carr, Chief Executive Officer**

Re: **Contracts for the Refurbishment of Bruce A at the Bruce Nuclear Facility Generating Station**

I write in connection with my authority as the Minister of Energy in order to exercise the statutory power of ministerial direction that I have in respect of the Ontario Power Authority (the "OPA") under subsections 25.32 (4) and (7) of the *Electricity Act, 1998* (the "Act").

As contemplated under subsection 25.32 (4) of the Act, the Ministry of Energy instituted an historic initiative to procure electricity capacity at the Bruce nuclear power generation facilities and thereby increase the long-term supply of electricity generating capacity within the Province of Ontario. This initiative is designed to facilitate, at the Bruce nuclear power generation facilities, the refurbishment and restart of Units 1 and 2, the refurbishment of Unit 3 and the replacement of the steam generators at Unit 4. Pursuant to subsection 25.32 (4) of the Act, I hereby direct the OPA to assume, as of the date the Refurbishment Agreement (as defined below) is executed, the responsibility for exercising all powers and performing all duties of the Ministry of Energy under the capacity initiative referred to above.

Pursuant to subsection 25.32 (7) of the Act, as a result of the capacity initiative referred to above, I hereby direct the OPA to execute and deliver to the relevant counterparties on October 17, 2005 the following contracts:

1. the Bruce Power Refurbishment Implementation Agreement (the "Refurbishment Agreement") between Bruce Power A L.P., Bruce Power L.P. and the Ontario Power Authority, in the form which is enclosed with this Direction; and

2. the Bruce Power Sharing In Transfers and Refinancings Agreement (the "Refinancing Agreement") between Bruce Power A L.P., Ontario Municipal Employees Retirement Board, TransCanada Corporation and the Ontario Power Authority, in the form which is enclosed with this Direction.

In addition, pursuant to subsection 25.32 (7) of the Act, as a result of the initiative referred to above, I hereby direct the OPA to execute and deliver to the Ministry of Energy the contract between the OPA and the Ministry of Energy, which is enclosed with this Direction.

Further, pursuant to my authority under section 25.32 of the Act, the OPA is hereby directed to execute and deliver such ancillary documents, deeds and instruments required in connection with, pertaining to, or arising out of, the execution of the above-noted Refurbishment Agreement or Refinancing Agreement.

This Direction shall be effective and binding as of the date hereof.

Dated: October 14, 2005

Donna Cansfield

Donna Cansfield
Minister of Energy

APPENDIX 13

Provincial Land Use Policy

Ontario

2005

Provincial Policy Statement

This publication was produced by the Ministry of Municipal Affairs and Housing.

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Materials may be available to assist planning authorities and decision-makers with implementing the policies of the Provincial Policy Statement. Please visit the Ministry Web site at www.mah.gov.on.ca for more information.

Approved by the Lieutenant Governor in Council, Order in Council No. 140/2005

This Provincial Policy Statement was issued under Section 3 of the *Planning Act* and came into effect March 1, 2005. It replaces the Provincial Policy Statement issued May 22, 1996, and amended February 1, 1997.

TABLE OF CONTENTS

Part I: PREAMBLE

The Provincial Policy Statement provides policy direction on matters of provincial interest related to land use planning and development. As a key part of Ontario's policy-led planning system, the Provincial Policy Statement sets the policy foundation for regulating the development and use of land. It also supports the provincial goal to enhance the quality of life for the citizens of Ontario.

The Provincial Policy Statement provides for appropriate development while protecting resources of provincial interest, public health and safety, and the quality of the natural environment. The Provincial Policy Statement supports improved land use planning and management, which contributes to a more effective and efficient land use planning system.

The policies of the Provincial Policy Statement may be complemented by provincial plans or by locally-generated policies regarding matters of municipal interest. Provincial plans and municipal official plans provide a framework for comprehensive, integrated and long-term planning that supports and integrates the principles of strong communities, a clean and healthy environment and economic growth, for the long term.

Land use planning is only one of the tools for implementing provincial interests. A wide range of legislation, regulations, policies and programs may also affect planning matters, and assist in implementing these interests.

Part II: LEGISLATIVE AUTHORITY

The Provincial Policy Statement is issued under the authority of Section 3 of the *Planning Act* and came into effect on March 1, 2005. It applies to all applications, matters or proceedings commenced on or after March 1, 2005.

In respect of the exercise of any authority that affects a planning matter, Section 3 of the *Planning Act* requires that decisions affecting planning matters "shall be consistent with" policy statements issued under the Act.

Part III: HOW TO READ THE PROVINCIAL POLICY STATEMENT

A policy-led planning system recognizes and addresses the complex inter-relationships among environmental, economic and social factors in land use planning. The Provincial Policy Statement supports a comprehensive, integrated and long-term approach to planning, and recognizes linkages among policy areas.

The Provincial Policy Statement is more than a set of individual policies. It is intended to be read in its entirety and the relevant policies are to be applied to each situation. A decision-maker should read all of the relevant policies as if they are specifically cross-referenced with each other. While specific policies sometimes refer to other policies for ease of use, these cross-references do not take away from the need to read the Provincial Policy Statement as a whole.

Part IV, Vision for Ontario's Land Use Planning System, provides the context for applying the Provincial Policy Statement. Implementation issues are addressed in the Implementation and Interpretation section.

Except for references to legislation which are traditionally italicized, italicized terms in the Provincial Policy Statement are defined in the Definitions section. For other terms, the normal meaning of the word applies. Terms may be italicized only in specific policies; for these terms, the defined meaning applies where they are italicized and the normal meaning applies where they are not italicized. Defined terms in the Definitions section are intended to capture both singular and plural forms of these terms in the policies.

There is no implied priority in the order in which the policies appear.

Part IV: VISION FOR ONTARIO'S LAND USE PLANNING SYSTEM

The long-term prosperity and social well-being of Ontarians depend on maintaining strong communities, a clean and healthy environment and a strong economy.

Ontario is a vast province with diverse urban, rural and northern communities which may face different challenges related to diversity in population levels, economic activity, pace of growth and physical and natural conditions. Some areas face challenges related to maintaining population and diversifying their economy, while other areas face challenges related to accommodating and managing the development and population growth which is occurring, while protecting important resources and the quality of the natural environment. The Provincial Policy Statement reflects this diversity and is based on good planning principles that apply in communities across Ontario.

The Provincial Policy Statement focuses growth within settlement areas and away from significant or sensitive resources and areas which may pose a risk to public health and safety. It recognizes that the wise management of development may involve directing, promoting or sustaining growth. Land use must be carefully managed to accommodate appropriate development to meet the full range of current and future needs, while achieving efficient development patterns.

Efficient development patterns optimize the use of land, resources and public investment in infrastructure and public service facilities. These land use patterns promote a mix of housing, employment, parks and open spaces, and transportation choices that facilitate pedestrian mobility and other modes of travel. They also support the financial well-being of the Province and municipalities over the long term, and minimize the undesirable effects of development, including impacts on air, water and other resources. Strong, liveable and healthy communities enhance social well-being and are economically and environmentally sound.

The Province's natural heritage resources, water, agricultural lands, mineral resources, and cultural heritage and archaeological resources provide important environmental, economic and social benefits. The wise use and management of these resources over the long term is a key provincial interest. The Province must ensure that its resources are managed in a sustainable way to protect essential ecological processes and public health and safety, minimize environmental and social impacts, and meet its long-term needs.

It is equally important to protect the overall health and safety of the population. The Provincial Policy Statement directs development away from areas of natural and human-made hazards, where these hazards cannot be mitigated. This preventative approach supports provincial and municipal financial well-being over the long term, protects public health and safety, and minimizes cost, risk and social disruption.

Taking action to conserve land and resources avoids the need for costly remedial measures to correct problems and supports economic and environmental principles.

Strong communities, a clean and healthy environment and a strong economy are inextricably linked. Long-term prosperity, environmental health and social well-being should take precedence over short-term considerations.

The fundamental principles set out in the Provincial Policy Statement apply throughout Ontario, despite regional variations. To support our collective well-being, now and in the future, all land use must be well managed.

The Vision for Ontario's Land Use Planning System may be further articulated through planning direction for specific areas of the Province issued through provincial plans, such as those plans created under the *Niagara Escarpment Planning and Development Act* and the *Oak Ridges Moraine Conservation Act, 2001*, which are approved by the Lieutenant Governor in Council or the Minister of Municipal Affairs and Housing.

Part V: POLICIES

1.0 BUILDING STRONG COMMUNITIES

Ontario's long-term prosperity, environmental health and social well-being depend on wisely managing change and promoting efficient land use and development patterns. Efficient land use and development patterns support strong, liveable and healthy communities, protect the environment and public health and safety, and facilitate economic growth.

Accordingly:

1.1 MANAGING AND DIRECTING LAND USE TO ACHIEVE EFFICIENT DEVELOPMENT AND LAND USE PATTERNS

1.1.1 Healthy, liveable and safe communities are sustained by:

a) promoting efficient development and land use patterns which sustain the financial well-being of the Province and municipalities over the long term;
b) accommodating an appropriate range and mix of residential, employment (including industrial, commercial and institutional uses), recreational and open space uses to meet long-term needs;
c) avoiding development and land use patterns which may cause environmental or public health and safety concerns;
d) avoiding development and land use patterns that would prevent the efficient expansion of *settlement areas* in those areas which are adjacent or close to *settlement areas*;
e) promoting cost-effective development standards to minimize land consumption and servicing costs;
f) improving accessibility for persons with disabilities and the elderly by removing and/or preventing land use barriers which restrict their full participation in society; and
g) ensuring that necessary *infrastructure* and *public service facilities* are or will be available to meet current and projected needs.

1.1.2 Sufficient land shall be made available through *intensification* and *redevelopment* and, if necessary, *designated growth areas*, to accommodate an appropriate range and mix of employment opportunities, housing and other land uses to meet projected needs for a time horizon of up to 20 years. However, where an alternate time period has been established for specific areas of the Province as a result of a provincial planning exercise or a *provincial plan*, that time frame may be used for municipalities within the area.

1.1.3 Settlement Areas

1.1.3.1 *Settlement areas* shall be the focus of growth and their vitality and regeneration shall be promoted.

1.1.3.2 Land use patterns within *settlement areas* shall be based on:

a) densities and a mix of land uses which:
   1. efficiently use land and resources;
   2. are appropriate for, and efficiently use, the *infrastructure* and *public service facilities* which are planned or available, and avoid the need for their unjustified and/or uneconomical expansion; and
   3. minimize negative impacts to air quality and climate change, and promote energy efficiency in accordance with policy 1.8; and

b) a range of uses and opportunities for *intensification* and *redevelopment* in accordance with the criteria in policy 1.1.3.3.

1.1.3.3 Planning authorities shall identify and promote opportunities for *intensification* and *redevelopment* where this can be accommodated taking into account existing building stock or areas, including *brownfield sites*, and the availability of suitable existing or planned *infrastructure* and *public service facilities* required to accommodate projected needs.

Intensification and *redevelopment* shall be directed in accordance with the policies of Section 2: Wise Use and Management of Resources and Section 3: Protecting Public Health and Safety.

1.1.3.4 Appropriate development standards should be promoted which facilitate *intensification, redevelopment* and compact form, while maintaining appropriate levels of public health and safety.

1.1.3.5 Planning authorities shall establish and implement minimum targets for *intensification* and *redevelopment* within built-up areas. However, where provincial targets are established through *provincial plans*, the provincial target shall represent the minimum target for affected areas.

1.1.3.6 Planning authorities shall establish and implement phasing policies to ensure that specified targets for *intensification* and *redevelopment* are achieved prior to, or concurrent with, new development within *designated growth areas*.

1.1.3.7 New development taking place in *designated growth areas* should occur adjacent to the existing built-up area and shall have a compact form, mix of uses and densities that allow for the efficient use of land, *infrastructure* and *public service facilities.*

1.1.3.8 Planning authorities shall establish and implement phasing policies to ensure the orderly progression of development within *designated growth areas* and the timely provision of the *infrastructure* and *public service facilities* required to meet current and projected needs.–

1.1.3.9 A planning authority may identify a *settlement area* or allow the expansion of a *settlement area* boundary only at the time of a *comprehensive review* and only where it has been demonstrated that:

a) sufficient opportunities for growth are not available through *intensification*, *redevelopment* and *designated growth areas* to accommodate the projected needs over the identified planning horizon;
b) the *infrastructure* and *public service facilities* which are planned or available are suitable for the development over the long term and protect public health and safety;
c) in *prime agricultural areas*:
    1. the lands do not comprise *specialty crop areas*;
    2. there are no reasonable alternatives which avoid *prime agricultural areas*; and
    3. there are no reasonable alternatives on lower priority agricultural lands in *prime agricultural areas*; and
d) impacts from new or expanding *settlement areas* on agricultural operations which are adjacent or close to the *settlement area* are mitigated to the extent feasible.

In determining the most appropriate direction for expansions to the boundaries of *settlement areas* or the identification of a *settlement area* by a planning authority, a planning authority shall apply the policies of Section 2: Wise Use and Management of Resources and Section 3: Protecting Public Health and Safety.

1.1.4 Rural Areas in Municipalities

1.1.4.1 In *rural areas* located in municipalities:

a) permitted uses and activities shall relate to the management or use of resources, resource-based recreational activities, limited residential development and other rural land uses;
b) development shall be appropriate to the *infrastructure* which is planned or available, and avoid the need for the unjustified and/or uneconomical expansion of this *infrastructure*;
c) new land uses, including the creation of lots, and new or expanding livestock facilities, shall comply with the *minimum distance separation formulae*;
d) development that is compatible with the rural landscape and can be sustained by rural service levels should be promoted;
e) locally-important agricultural and resource areas should be designated and protected by directing non-related development to areas where it will not constrain these uses;

f) opportunities should be retained to locate new or expanding land uses that require separation from other uses; and

g) recreational, tourism and other economic opportunities should be promoted.

1.1.5 Rural Areas in Territory Without Municipal Organization

1.1.5.1 In *rural areas* located in territory without municipal organization, the focus of development activity shall be activities and land uses related to the management or use of resources and resource-based recreational activities.

1.1.5.2 The establishment of new permanent townsites shall not be permitted.

1.1.5.3 In areas adjacent to and surrounding municipalities, only development that is related to the management or use of resources and resource-based recreational activity shall be permitted unless:

a) the area forms part of a planning area; and
b) it has been determined, as part of a *comprehensive review*, that the impacts of growth will not place an undue strain on the *public service facilities* and *infrastructure* provided by adjacent municipalities, regions and/or the Province.

1.2 COORDINATION

1.2.1 A coordinated, integrated and comprehensive approach should be used when dealing with planning matters within municipalities, or which cross lower, single and/or upper-tier municipal boundaries, including:

a) managing and/or promoting growth and development;
b) managing natural heritage, water, agricultural, mineral, and cultural heritage and archaeological resources;
c) *infrastructure*, *public service facilities* and *waste management systems*;
d) ecosystem, shoreline and watershed related issues;
e) natural and human-made hazards; and
f) population, housing and employment projections, based on *regional market areas*.

1.2.2 Where planning is conducted by an upper-tier municipality, the upper-tier municipality in consultation with lower-tier municipalities shall:

a) identify, coordinate and allocate population, housing and employment projections for lower-tier municipalities. Allocations and projections by upper-tier municipalities shall be based on and reflect *provincial plans* where these exist;
b) identify areas where growth will be directed, including the identification of nodes and the corridors linking these nodes;

c) identify targets for *intensification* and *redevelopment* within all or any of the lower-tier municipalities, including minimum targets that should be met before expansion of the boundaries of *settlement areas* is permitted in accordance with policy 1.1.3.9;

d) where transit corridors exist or are to be developed, identify density targets for areas adjacent or in proximity to these corridors, including minimum targets that should be met before expansion of the boundaries of *settlement areas* is permitted in accordance with policy 1.1.3.9; and

e) identify and provide policy direction for the lower-tier municipalities on matters that cross municipal boundaries.

1.2.3 Where there is no upper-tier municipality, planning authorities shall ensure that policy 1.2.2 is addressed as part of the planning process, and should coordinate these matters with adjacent planning authorities.

1.3 EMPLOYMENT AREAS

1.3.1 Planning authorities shall promote economic development and competitiveness by:

a) providing for an appropriate mix and range of employment (including industrial, commercial and institutional uses) to meet long-term needs;

b) providing opportunities for a diversified economic base, including maintaining a range and choice of suitable sites for employment uses which support a wide range of economic activities and ancillary uses, and take into account the needs of existing and future businesses;

c) planning for, protecting and preserving *employment areas* for current and future uses; and

d) ensuring the necessary *infrastructure* is provided to support current and projected needs.

1.3.2 Planning authorities may permit conversion of lands within *employment areas* to non-employment uses through a *comprehensive review*, only where it has been demonstrated that the land is not required for employment purposes over the long term and that there is a need for the conversion.

1.4 HOUSING

1.4.1 To provide for an appropriate range of housing types and densities required to meet projected requirements of current and future residents of the *regional market area* identified in policy 1.4.3, planning authorities shall:

a) maintain at all times the ability to accommodate residential growth for a minimum of 10 years through *residential intensification* and *redevelopment* and, if necessary, lands which are *designated and available* for residential development; and

b) maintain at all times where new development is to occur, land with servicing capacity sufficient to provide at least a 3 year supply of residential units available through lands suitably zoned to facilitate *residential intensification* and *redevelopment*, and land in draft approved and registered plans.

1.4.2 Where planning is conducted by an upper-tier municipality:

a) the land and unit supply maintained by the lower-tier municipality identified in policy 1.4.1 shall be based on and reflect the allocation of population and units by the upper-tier municipality; and
b) the allocation of population and units by the upper-tier municipality shall be based on and reflect *provincial plans* where these exist.

1.4.3 Planning authorities shall provide for an appropriate range of housing types and densities to meet projected requirements of current and future residents of the *regional market area* by:

a) establishing and implementing minimum targets for the provision of housing which is *affordable* to *low and moderate income households.* However, where planning is conducted by an upper-tier municipality, the upper-tier municipality in consultation with the lower-tier municipalities may identify a higher target(s) which shall represent the minimum target(s) for these lower-tier municipalities;
b) permitting and facilitating:
   1. all forms of housing required to meet the social, health and well-being requirements of current and future residents, including *special needs* requirements; and
   2. all forms of *residential intensification* and *redevelopment* in accordance with policy 1.1.3.3;
c) directing the development of new housing towards locations where appropriate levels of *infrastructure* and *public service facilities* are or will be available to support current and projected needs;
d) promoting densities for new housing which efficiently use land, resources, *infrastructure* and *public service facilities*, and support the use of alternative transportation modes and public transit in areas where it exists or is to be developed; and
e) establishing development standards for *residential intensification*, *redevelopment* and new residential development which minimize the cost of housing and facilitate compact form, while maintaining appropriate levels of public health and safety.

1.5 PUBLIC SPACES, PARKS AND OPEN SPACE

1.5.1 Healthy, active communities should be promoted by:

a) planning public streets, spaces and facilities to be safe, meet the needs of pedestrians, and facilitate pedestrian and non-motorized movement, including but not limited to, walking and cycling;
b) providing for a full range and equitable distribution of publicly-accessible built and natural settings for *recreation*, including facilities, parklands, open space areas, trails and, where practical, water-based resources;
c) providing opportunities for public access to shorelines; and
d) considering the impacts of planning decisions on provincial parks, conservation reserves and conservation areas.

1.6 INFRASTRUCTURE AND PUBLIC SERVICE FACILITIES

1.6.1 *Infrastructure* and *public service facilities* shall be provided in a coordinated, efficient and cost-effective manner to accommodate projected needs.

Planning for *infrastructure* and *public service facilities* shall be integrated with planning for growth so that these are available to meet current and projected needs.

1.6.2 The use of existing *infrastructure* and *public service facilities* should be optimized, wherever feasible, before consideration is given to developing new *infrastructure* and *public service facilities*.

1.6.3 *Infrastructure* and *public service facilities* should be strategically located to support the effective and efficient delivery of emergency management services.

Where feasible, *public service facilities* should be co-located to promote cost-effectiveness and facilitate service integration.

1.6.4 Sewage and Water

1.6.4.1 Planning for *sewage and water services* shall:

a) direct and accommodate expected growth in a manner that promotes the efficient use of existing:
   1. *municipal sewage services* and *municipal water services*; and
   2. *private communal sewage services* and *private communal water services*, where *municipal sewage services* and *municipal water services* are not available;
b) ensure that these systems are provided in a manner that:
   1. can be sustained by the water resources upon which such services rely;
   2. is financially viable and complies with all regulatory requirements; and
   3. protects human health and the natural environment;

c) promote water conservation and water use efficiency;

d) integrate servicing and land use considerations at all stages of the planning process; and

e) subject to the hierarchy of services provided in policies 1.6.4.2, 1.6.4.3 and 1.6.4.4, allow lot creation only if there is confirmation of sufficient *reserve sewage system capacity* and *reserve water system capacity* within *municipal sewage services* and *municipal water services* or *private communal sewage services* and *private communal water services*. The determination of sufficient *reserve sewage system capacity* shall include treatment capacity for hauled sewage from *private communal sewage services* and *individual on-site sewage services*.

1.6.4.2 *Municipal sewage services* and *municipal water services* are the preferred form of servicing for *settlement areas*. *Intensification* and *redevelopment* within *settlement areas* on existing *municipal sewage services* and *municipal water services* should be promoted, wherever feasible.

1.6.4.3 Municipalities may choose to use *private communal sewage services* and *private communal water services*, and where policy 1.6.4.4 permits, *individual on-site sewage services* and *individual on-site water services,* where:

a) *municipal sewage services* and *municipal water services* are not provided; and

b) the municipality has established policies to ensure that the services to be provided satisfy the criteria set out in policy 1.6.4.1.

1.6.4.4 *Individual on-site sewage services* and *individual on-site water services* shall be used for a new development of five or less lots or private residences where *municipal sewage services* and *municipal water services* or *private communal sewage services* and *private communal water services* are not provided and where site conditions are suitable for the long-term provision of such services. Despite this, *individual on-site sewage services* and *individual on-site water services* may be used to service more than five lots or private residences in *rural areas* provided these services are solely for those uses permitted by policy 1.1.4.1(a) and site conditions are suitable for the long-term provision of such services.

1.6.4.5 *Partial services* shall only be permitted in the following circumstances:

a) where they are necessary to address failed *individual on-site sewage services* and *individual on-site water services* in existing development; and

b) within *settlement areas*, to allow for infilling and rounding out of existing development on *partial services* provided that:

1. the development is within the *reserve sewage system capacity* and *reserve water system capacity*; and
2. site conditions are suitable for the long-term provision of such services.

1.6.5 Transportation Systems

1.6.5.1 *Transportation systems* should be provided which are safe, energy efficient, facilitate the movement of people and goods, and are appropriate to address projected needs.

1.6.5.2 Efficient use shall be made of existing and planned *infrastructure*.

1.6.5.3 Connectivity within and among *transportation systems* and modes should be maintained and, where possible, improved including connections which cross jurisdictional boundaries.

1.6.5.4 A land use pattern, density and mix of uses should be promoted that minimize the length and number of vehicle trips and support the development of viable choices and plans for public transit and other alternative transportation modes, including commuter rail and bus.

1.6.5.5 Transportation and land use considerations shall be integrated at all stages of the planning process.

1.6.6 Transportation and Infrastructure Corridors

1.6.6.1 Planning authorities shall plan for and protect corridors and rights-of-way for transportation, transit and *infrastructure* facilities to meet current and projected needs.

1.6.6.2 Planning authorities shall not permit *development* in *planned corridors* that could preclude or negatively affect the use of the corridor for the purpose(s) for which it was identified.

1.6.6.3 The preservation and reuse of abandoned corridors for purposes that maintain the corridor's integrity and continuous linear characteristics should be encouraged, wherever feasible.

1.6.6.4 When planning for corridors and rights-of-way for significant transportation and *infrastructure* facilities, consideration will be given to the significant resources in Section 2: Wise Use and Management of Resources.

1.6.7 Airports

1.6.7.1 Planning for land uses in the vicinity of *airports* shall be undertaken so that:

a) the long-term operation and economic role of *airports* is protected; and
b) *airports* and *sensitive land uses* are appropriately designed, buffered and/or separated from each other to prevent adverse effects from odour, noise and other contaminants.

1.6.7.2 *Airports* shall be protected from incompatible land uses and development by:

a) prohibiting new residential *development* and other sensitive land uses in areas near *airports* above 30 NEF/NEP, as set out on maps (as revised from time to time) that have been reviewed by Transport Canada;
b) considering redevelopment of existing residential uses and other sensitive land uses or infilling of residential and other sensitive land uses in areas above 30 NEF/NEP only if it has been demonstrated that there will be no negative impacts on the long-term function of the *airport*; and
c) discouraging land uses which may cause a potential aviation safety hazard.

1.6.8 Waste Management

1.6.8.1 *Waste management systems* need to be provided that are of an appropriate size and type to accommodate present and future requirements, and facilitate, encourage and promote reduction, reuse and recycling objectives.

Waste management systems shall be located and designed in accordance with provincial legislation and standards.

1.7 LONG-TERM ECONOMIC PROSPERITY

1.7.1 Long-term economic prosperity should be supported by:

a) optimizing the long-term availability and use of land, resources, *infrastructure* and *public service facilities*;
b) maintaining and, where possible, enhancing the vitality and viability of downtowns and mainstreets;
c) promoting the redevelopment of *brownfield sites*;
d) providing for an efficient, cost-effective, reliable *multi-modal transportation system* that is integrated with adjacent systems and those of other jurisdictions, and is appropriate to address projected needs;
e) planning so that major facilities (such as airports, transportation/transit/rail infrastructure and corridors, intermodal facilities, sewage treatment facilities, waste management systems, oil and gas pipelines, industries and resource extraction activities) and *sensitive land uses* are appropriately designed, buffered and/or separated from each other to prevent *adverse effects* from odour, noise and other contaminants, and minimize risk to public health and safety;
f) providing opportunities for sustainable tourism development;
g) promoting the sustainability of the agri-food sector by protecting agricultural resources and minimizing land use conflicts; and
h) providing opportunities for increased energy generation, supply and conservation, including *alternative energy systems* and *renewable energy systems*.

1.8 ENERGY AND AIR QUALITY

1.8.1 Planning authorities shall support energy efficiency and improved air quality through land use and development patterns which:

a) promote compact form and a structure of nodes and corridors;
b) promote the use of public transit and other alternative transportation modes in and between residential, employment (including commercial, industrial and institutional uses) and other areas where these exist or are to be developed;
c) focus major employment, commercial and other travel-intensive land uses on sites which are well served by public transit where this exists or is to be developed, or designing these to facilitate the establishment of public transit in the future;
d) improve the mix of employment and housing uses to shorten commute journeys and decrease transportation congestion; and
e) promote design and orientation which maximize the use of alternative or renewable energy, such as solar and wind energy, and the mitigating effects of vegetation.

1.8.2 Increased energy supply should be promoted by providing opportunities for energy generation facilities to accommodate current and projected needs, and the use of *renewable energy systems* and *alternative energy systems*, where feasible.

1.8.3 *Alternative energy systems* and *renewable energy systems* shall be permitted in *settlement areas, rural areas* and *prime agricultural areas* in accordance with *provincial and federal requirements*. In *rural areas* and *prime agricultural areas*, these systems should be designed and constructed to minimize impacts on agricultural operations.

2.0 WISE USE AND MANAGEMENT OF RESOURCES

Ontario's long-term prosperity, environmental health, and social well-being depend on protecting natural heritage, water, agricultural, mineral and cultural heritage and archaeological resources for their economic, environmental and social benefits.

Accordingly:

2.1 NATURAL HERITAGE

2.1.1 Natural features and areas shall be protected for the long term.

2.1.2 The diversity and connectivity of natural features in an area, and the long-term *ecological function* and biodiversity of *natural heritage systems*, should be maintained, restored or, where possible, improved, recognizing linkages between and among *natural heritage features and areas, surface water features* and *ground water features.*

2.1.3 *Development* and *site alteration* shall not be permitted in:

a) *significant* habitat of *endangered species* and *threatened species*;
b) *significant wetlands* in Ecoregions 5E, 6E and 7E[1]; and
c) *significant coastal wetlands*.

2.1.4 *Development* and *site alteration* shall not be permitted in:

a) *significant wetlands* in the Canadian Shield north of Ecoregions 5E, 6E and 7E[1];
b) *significant woodlands* south and east of the Canadian Shield[2];
c) *significant valleylands* south and east of the Canadian Shield[2];
d) *significant wildlife habitat*; and
e) *significant areas of natural and scientific interest*

unless it has been demonstrated that there will be no *negative impacts* on the natural features or their *ecological functions*.

2.1.5 *Development* and *site alteration* shall not be permitted in *fish habitat* except in accordance with *provincial and federal requirements*.

2.1.6 *Development* and *site alteration* shall not be permitted on *adjacent lands* to the *natural heritage features and areas* identified in policies 2.1.3, 2.1.4 and 2.1.5 unless the *ecological function* of the *adjacent lands* has been evaluated and it has been demonstrated that there will be no *negative impacts* on the natural features or on their *ecological functions*.

[1] Ecoregions 5E, 6E and 7E are shown on Figure 1.
[2] Areas south and east of the Canadian Shield are shown on Figure 1.

2.1.7 Nothing in policy 2.1 is intended to limit the ability of existing agricultural uses to continue.

2.2 WATER

2.2.1 Planning authorities shall protect, improve or restore the *quality and quantity of water* by:

a) using the *watershed* as the ecologically meaningful scale for planning;
b) minimizing potential *negative impacts*, including cross-jurisdictional and cross-*watershed* impacts;
c) identifying *surface water features*, *ground water features*, *hydrologic functions* and *natural heritage features and areas* which are necessary for the ecological and hydrological integrity of the *watershed*;
d) implementing necessary restrictions on *development* and *site alteration* to:
   1. protect all municipal drinking water supplies and *designated vulnerable areas*; and
   2. protect, improve or restore *vulnerable* surface and ground water, *sensitive surface water features* and *sensitive ground water features*, and their *hydrologic functions*;
e) maintaining linkages and related functions among *surface water features, ground water features*, *hydrologic functions* and *natural heritage features and areas*;
f) promoting efficient and sustainable use of water resources, including practices for water conservation and sustaining water quality; and
g) ensuring stormwater management practices minimize stormwater volumes and contaminant loads, and maintain or increase the extent of vegetative and pervious surfaces.

2.2.2 *Development* and *site alteration* shall be restricted in or near *sensitive surface water features* and *sensitive ground water features* such that these features and their related *hydrologic functions* will be protected, improved or restored.

Mitigative measures and/or alternative development approaches may be required in order to protect, improve or restore *sensitive surface water features, sensitive ground water features,* and their *hydrologic functions*.

2.3 AGRICULTURE

2.3.1 *Prime agricultural areas* shall be protected for long-term use for agriculture.

Prime agricultural areas are areas where *prime agricultural lands* predominate. *Specialty crop areas* shall be given the highest priority for protection, followed by Classes 1, 2 and 3 soils, in this order of priority.

2.3.2 Planning authorities shall designate *specialty crop areas* in accordance with evaluation procedures established by the Province, as amended from time to time.

2.3.3 Permitted Uses

2.3.3.1 In *prime agricultural areas*, permitted uses and activities are: *agricultural uses*, *secondary uses* and *agriculture-related uses.*

Proposed new *secondary uses* and *agriculture-related uses* shall be compatible with, and shall not hinder, surrounding agricultural operations. These uses shall be limited in scale, and criteria for these uses shall be included in municipal planning documents as recommended by the Province, or based on municipal approaches which achieve the same objective.

2.3.3.2 In *prime agricultural areas*, all types, sizes and intensities of *agricultural uses* and *normal farm practices* shall be promoted and protected in accordance with provincial standards.

2.3.3.3 New land uses, including the creation of lots, and new or expanding livestock facilities shall comply with the *minimum distance separation formulae.*

2.3.4 Lot Creation and Lot Adjustments

2.3.4.1 Lot creation in *prime agricultural areas* is discouraged and may only be permitted for:

a) *agricultural uses*, provided that the lots are of a size appropriate for the type of agricultural use(s) common in the area and are sufficiently large to maintain flexibility for future changes in the type or size of agricultural operations;
b) *agriculture-related uses*, provided that any new lot will be limited to a minimum size needed to accommodate the use and appropriate *sewage and water services*;
c) a *residence surplus to a farming operation* as a result of farm consolidation, provided that the planning authority ensures that new residential dwellings are prohibited on any vacant remnant parcel of farmland created by the severance. The approach used to ensure that no new residential dwellings are permitted on the remnant parcel may be recommended by the Province, or based on municipal approaches which achieve the same objective; and
d) *infrastructure*, where the facility or corridor cannot be accommodated through the use of easements or rights-of-way.

2.3.4.2 Lot adjustments in *prime agricultural areas* may be permitted for *legal or technical reasons*.

2.3.4.3 The creation of new residential lots in *prime agricultural areas* shall not be permitted, except in accordance with policy 2.3.4.1(c).

2.3.5 Removal of Land from Prime Agricultural Areas

2.3.5.1 Planning authorities may only exclude land from *prime agricultural areas* for:

a) expansions of or identification of *settlement areas* in accordance with policy 1.1.3.9;
b) extraction of *minerals*, *petroleum resources* and *mineral aggregate resources*, in accordance with policies 2.4 and 2.5; and
c) limited non-residential uses, provided that:
   1. the land does not comprise a *specialty crop area*;
   2. there is a demonstrated need within the planning horizon provided for in policy 1.1.2 for additional land to be designated to accommodate the proposed use;
   3. there are no reasonable alternative locations which avoid *prime agricultural areas*; and
   4. there are no reasonable alternative locations in *prime agricultural areas* with lower priority agricultural lands.

2.3.5.2 Impacts from any new or expanding non-agricultural uses on surrounding agricultural operations and lands should be mitigated to the extent feasible.

2.4 MINERALS AND PETROLEUM

2.4.1 *Minerals* and *petroleum resources* shall be protected for long-term use.

2.4.2 Protection of Long-Term Resource Supply

2.4.2.1 *Mineral mining operations* and *petroleum resource operations* shall be protected from *development* and activities that would preclude or hinder their expansion or continued use or which would be incompatible for reasons of public health, public safety or environmental impact.

2.4.2.2 In areas adjacent to or in known *mineral deposits* or known *petroleum resources*, and in *significant areas of mineral potential* and *significant areas of petroleum potential*, *development* and activities which would preclude or hinder the establishment of new operations or access to the resources shall only be permitted if:

a) resource use would not be feasible; or
b) the proposed land use or development serves a greater long-term public interest; and
c) issues of public health, public safety and environmental impact are addressed.

2.4.3 Rehabilitation

2.4.3.1 Rehabilitation to accommodate subsequent land uses shall be required after extraction and other related activities have ceased. Progressive rehabilitation should be undertaken wherever feasible.

2.4.4 Extraction in Prime Agricultural Areas

2.4.4.1 Extraction of *minerals* and *petroleum resources* is permitted in *prime agricultural areas*, provided that the site is rehabilitated.

2.5 MINERAL AGGREGATE RESOURCES

2.5.1 *Mineral aggregate resources* shall be protected for long-term use.

2.5.2 Protection of Long-Term Resource Supply

2.5.2.1 As much of the *mineral aggregate resources* as is realistically possible shall be made available as close to markets as possible.

Demonstration of need for *mineral aggregate resources*, including any type of supply/demand analysis, shall not be required, notwithstanding the availability, designation or licensing for extraction of *mineral aggregate resources* locally or elsewhere.

2.5.2.2 Extraction shall be undertaken in a manner which minimizes social and environmental impacts.

2.5.2.3 The conservation of *mineral aggregate resources* should be promoted by making provision for the recovery of these resources, wherever feasible.

2.5.2.4 *Mineral aggregate operations* shall be protected from *development* and activities that would preclude or hinder their expansion or continued use or which would be incompatible for reasons of public health, public safety or environmental impact. Existing *mineral aggregate operations* shall be permitted to continue without the need for official plan amendment, rezoning or development permit under the *Planning Act.* When a license for extraction or operation ceases to exist, policy 2.5.2.5 continues to apply.

2.5.2.5 In areas adjacent to or in known *deposits of mineral aggregate resources, development* and activities which would preclude or hinder the establishment of new operations or access to the resources shall only be permitted if:

a) resource use would not be feasible; or
b) the proposed land use or development serves a greater long-term public interest; and
c) issues of public health, public safety and environmental impact are addressed.

2.5.3 Rehabilitation

2.5.3.1 Progressive and final rehabilitation shall be required to accommodate subsequent land uses, to promote land use compatibility, and to recognize the interim nature of extraction. Final rehabilitation shall take surrounding land use and approved land use designations into consideration.

2.5.3.2 In parts of the Province not designated under the *Aggregate Resources Act*, rehabilitation standards that are compatible with those under the Act should be adopted for extraction operations on private lands.

2.5.4 Extraction in Prime Agricultural Areas

2.5.4.1 In *prime agricultural areas*, on *prime agricultural land*, extraction of *mineral aggregate resources* is permitted as an interim use provided that rehabilitation of the site will be carried out so that substantially the same areas and same average soil quality for agriculture are restored.

On these *prime agricultural lands*, complete agricultural rehabilitation is not required if:

a) there is a substantial quantity of *mineral aggregate resources* below the water table warranting extraction, or the depth of planned extraction in a quarry makes restoration of pre-extraction agricultural capability unfeasible;
b) other alternatives have been considered by the applicant and found unsuitable. The consideration of other alternatives shall include resources in areas of Canada Land Inventory Class 4 to 7 soils, resources on lands identified as *designated growth areas*, and resources on *prime agricultural lands* where rehabilitation is feasible. Where no other alternatives are found, *prime agricultural lands* shall be protected in this order of priority: *specialty crop areas*, Canada Land Inventory Classes 1, 2 and 3; and
c) agricultural rehabilitation in remaining areas is maximized.

2.5.5 Wayside Pits and Quarries, Portable Asphalt Plants and Portable Concrete Plants

2.5.5.1 *Wayside pits and quarries, portable asphalt plants* and *portable concrete plants* used on public authority contracts shall be permitted, without the need for an official plan amendment, rezoning, or development permit under the *Planning Act* in all areas, except those areas of existing development or particular environmental sensitivity which have been determined to be incompatible with extraction and associated activities.

2.6 CULTURAL HERITAGE AND ARCHAEOLOGY

2.6.1 *Significant built heritage resources* and *significant cultural heritage landscapes* shall be *conserved.*

2.6.2 *Development* and *site alteration* shall only be permitted on lands containing *archaeological resources* or *areas of archaeological potential* if the *significant archaeological resources* have been conserved by removal and documentation, or by preservation on site. Where *significant archaeological resources* must be preserved on site, only *development* and *site alteration* which maintain the heritage integrity of the site may be permitted.

2.6.3 *Development* and *site alteration* may be permitted on *adjacent lands* to *protected heritage property* where the proposed *development* and *site alteration* has been evaluated and it has been demonstrated that the *heritage attributes* of the *protected heritage property* will be *conserved.*

Mitigative measures and/or alternative development approaches may be required in order to conserve the *heritage attributes* of the *protected heritage property* affected by the adjacent *development* or *site alteration*.

3.0 PROTECTING PUBLIC HEALTH AND SAFETY

Ontario's long-term prosperity, environmental health and social well-being depend on reducing the potential for public cost or risk to Ontario's residents from natural or human-made hazards. Development shall be directed away from areas of natural or human-made hazards where there is an unacceptable risk to public health or safety or of property damage.

Accordingly:

3.1 NATURAL HAZARDS

3.1.1 Development shall generally be directed to areas outside of:

a) *hazardous lands* adjacent to the shorelines of the *Great Lakes - St. Lawrence River System* and *large inland lakes* which are impacted by *flooding hazards*, *erosion hazards* and/or *dynamic beach hazards*;
b) *hazardous lands* adjacent to *river, stream and small inland lake systems* which are impacted by *flooding hazards* and/or *erosion hazards*; and
c) *hazardous sites.*

3.1.2 *Development* and *site alteration* shall not be permitted within:

a) the *dynamic beach hazard*;
b) *defined portions of the one hundred year flood level along connecting channels* (the St. Mary's, St. Clair, Detroit, Niagara and St. Lawrence Rivers);
c) areas that would be rendered inaccessible to people and vehicles during times of *flooding hazards*, *erosion hazards* and/or *dynamic beach hazards*, unless it has been demonstrated that the site has safe access appropriate for the nature of the *development* and the natural hazard; and
d) a *floodway* regardless of whether the area of inundation contains high points of land not subject to flooding.

3.1.3 Despite policy 3.1.2, *development* and *site alteration* may be permitted in certain areas identified in policy 3.1.2:

a) in those exceptional situations where a *Special Policy Area* has been approved. The designation of a *Special Policy Area*, and any change or modification to the site-specific policies or boundaries applying to a *Special Policy Area*, must be approved by the Ministers of Municipal Affairs and Housing and Natural Resources prior to the approval authority approving such changes or modifications; or
b) where the *development* is limited to uses which by their nature must locate within the *floodway*, including flood and/or erosion control works or minor additions or passive non-structural uses which do not affect flood flows.

3.1.4 *Development* shall not be permitted to locate in *hazardous lands* and *hazardous sites* where the use is:

a) an institutional use associated with hospitals, nursing homes, pre-school, school nurseries, day care and schools, where there is a threat to the safe evacuation of the sick, the elderly, persons with disabilities or the young during an emergency as a result of flooding, failure of floodproofing measures or protection works, or erosion;
b) an essential emergency service such as that provided by fire, police and ambulance stations and electrical substations, which would be impaired during an emergency as a result of flooding, the failure of floodproofing measures and/or protection works, and/or erosion; and
c) uses associated with the disposal, manufacture, treatment or storage of *hazardous substances*.

3.1.5 Where the two zone concept for *flood plains* is applied, *development* and *site alteration* may be permitted in the *flood fringe*, subject to appropriate floodproofing to the *flooding hazard* elevation or another *flooding hazard* standard approved by the Minister of Natural Resources.

3.1.6 Further to policy 3.1.5, and except as prohibited in policies 3.1.2 and 3.1.4, *development* and *site alteration* may be permitted in those portions of *hazardous lands* and *hazardous sites* where the effects and risk to public safety are minor so as to be managed or mitigated in accordance with provincial standards, as determined by the demonstration and achievement of all of the following:

a) *development* and *site alteration* is carried out in accordance with *floodproofing standards*, *protection works standards*, and *access standards*;
b) vehicles and people have a way of safely entering and exiting the area during times of flooding, erosion and other emergencies;
c) new hazards are not created and existing hazards are not aggravated; and
d) no adverse environmental impacts will result.

3.2 HUMAN-MADE HAZARDS

3.2.1 Development on, abutting or adjacent to lands affected by *mine hazards*; *oil, gas and salt hazards*; or former *mineral mining operations*, *mineral aggregate operations* or *petroleum resource operations* may be permitted only if rehabilitation measures to address and mitigate known or suspected hazards are under-way or have been completed.

3.2.2 Contaminated sites shall be remediated as necessary prior to any activity on the site associated with the proposed use such that there will be no *adverse effects.*

4.0 IMPLEMENTATION AND INTERPRETATION

4.1 This Provincial Policy Statement applies to all applications, matters or proceedings commenced on or after March 1, 2005.

4.2 In accordance with Section 3 of the *Planning Act*, as amended by the *Strong Communities (Planning Amendment) Act, 2004*, a decision of the council of a municipality, a local board, a planning board, a minister of the Crown and a ministry, board, commission or agency of the government, including the Municipal Board, in respect of the exercise of any authority that affects a planning matter, "shall be consistent with" this Provincial Policy Statement.

Comments, submissions or advice that affect a planning matter that are provided by the council of a municipality, a local board, a planning board, a minister or ministry, board, commission or agency of the government "shall be consistent with" this Provincial Policy Statement.

4.3 This Provincial Policy Statement shall be read in its entirety and all relevant policies are to be applied to each situation.

4.4 In implementing the Provincial Policy Statement, the Minister of Municipal Affairs and Housing may take into account other considerations when making decisions to support strong communities, a clean and healthy environment and the economic vitality of the Province.

4.5 The official plan is the most important vehicle for implementation of this Provincial Policy Statement.

Comprehensive, integrated and long-term planning is best achieved through municipal official plans. Municipal official plans shall identify provincial interests and set out appropriate land use designations and policies. Municipal official plans should also coordinate cross-boundary matters to complement the actions of other planning authorities and promote mutually beneficial solutions.

Municipal official plans shall provide clear, reasonable and attainable policies to protect provincial interests and direct development to suitable areas.

In order to protect provincial interests, planning authorities shall keep their official plans up-to-date with this Provincial Policy Statement. The policies of this Provincial Policy Statement continue to apply after adoption and approval of a municipal official plan.

4.6 The policies of this Provincial Policy Statement represent minimum standards. This Provincial Policy Statement does not prevent planning authorities and decision-makers from going beyond the minimum standards established in specific policies, unless doing so would conflict with any policy of this Provincial Policy Statement.

4.7 A wide range of legislation and regulations may apply to decisions with respect to *Planning Act* applications. In some cases, a *Planning Act* proposal may also require approval under other legislation or regulation.

4.8 In addition to land use approvals under the *Planning Act*, *infrastructure* may also require approval under other legislation and regulations, including the *Environmental Assessment Act*; the *Canadian Environmental Assessment Act, 1992*; the *Environmental Protection Act*; the *Ontario Energy Board Act, 1998*; the *Ontario Water Resources Act*; the *Conservation Authorities Act*; the *Ontario Heritage Act*; and the *Safe Drinking Water Act, 2002*. An environmental assessment process may be applied to new infrastructure and modifications to existing infrastructure under applicable legislation.

4.9 *Provincial plans* shall take precedence over policies in this Provincial Policy Statement to the extent of any conflict. Examples of these are plans created under the *Niagara Escarpment Planning and Development Act* and the *Oak Ridges Moraine Conservation Act, 2001*.

4.10 The Province, in consultation with municipalities, other public bodies and stakeholders shall identify performance indicators for measuring the effectiveness of some or all of the policies. The Province shall monitor their implementation, including reviewing performance indicators concurrent with any review of this Provincial Policy Statement.

4.11 Municipalities are encouraged to establish performance indicators to monitor the implementation of the policies in their official plans.

5.0 FIGURE 1

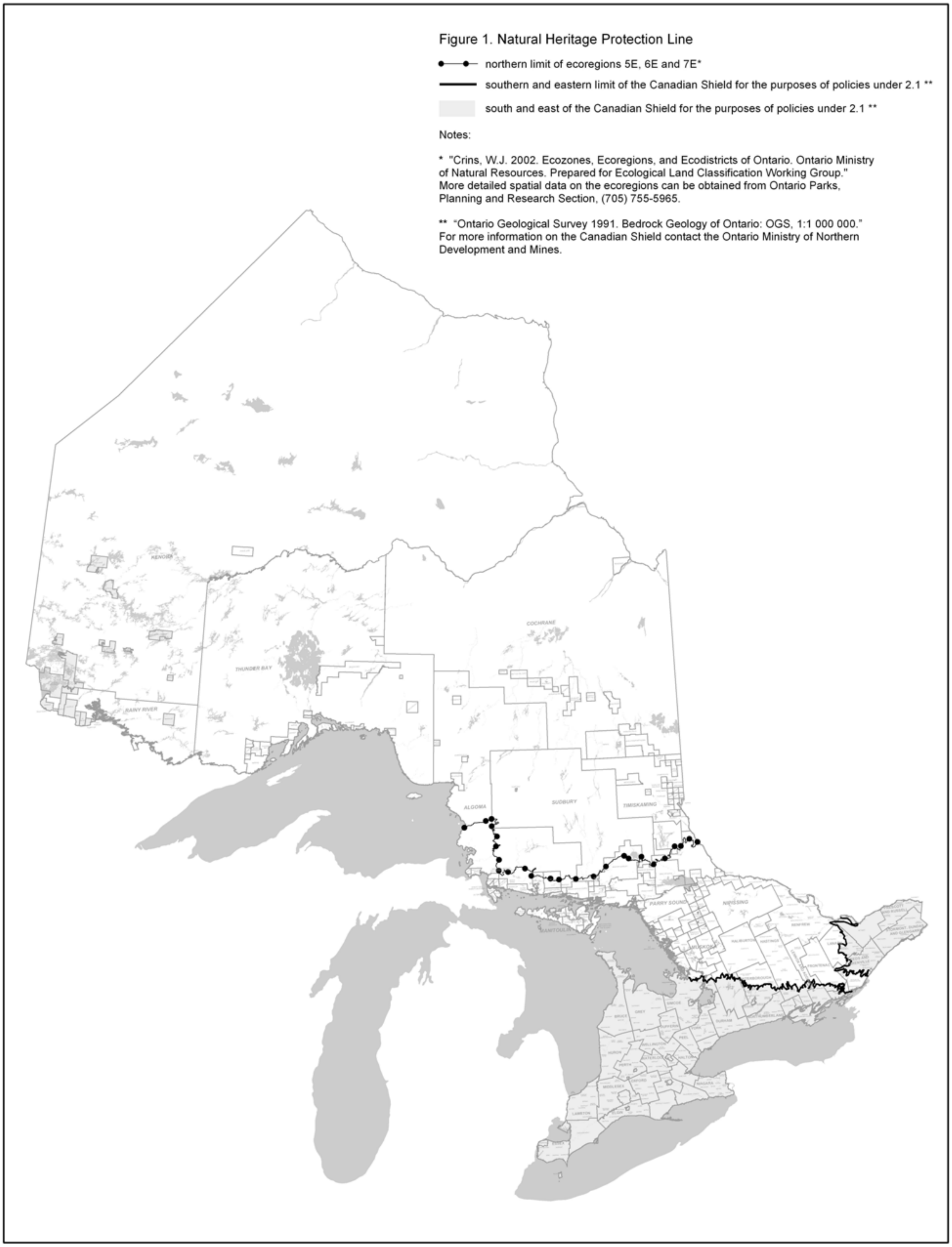
Figure 1. Natural Heritage Protection Line
northern limit of ecoregions 5E, 6E and 7E*
southern and eastern limit of the Canadian Shield for the purposes of policies under 2.1 **
south and east of the Canadian Shield for the purposes of policies under 2.1 **
Notes:
* "Crins, W.J. 2002. Ecozones, Ecoregions, and Ecodistricts of Ontario. Ontario Ministry of Natural Resources. Prepared for Ecological Land Classification Working Group." More detailed spatial data on the ecoregions can be obtained from Ontario Parks, Planning and Research Section, (705) 755-5965.
** "Ontario Geological Survey 1991. Bedrock Geology of Ontario: OGS, 1:1 000 000." For more information on the Canadian Shield contact the Ontario Ministry of Northern Development and Mines.

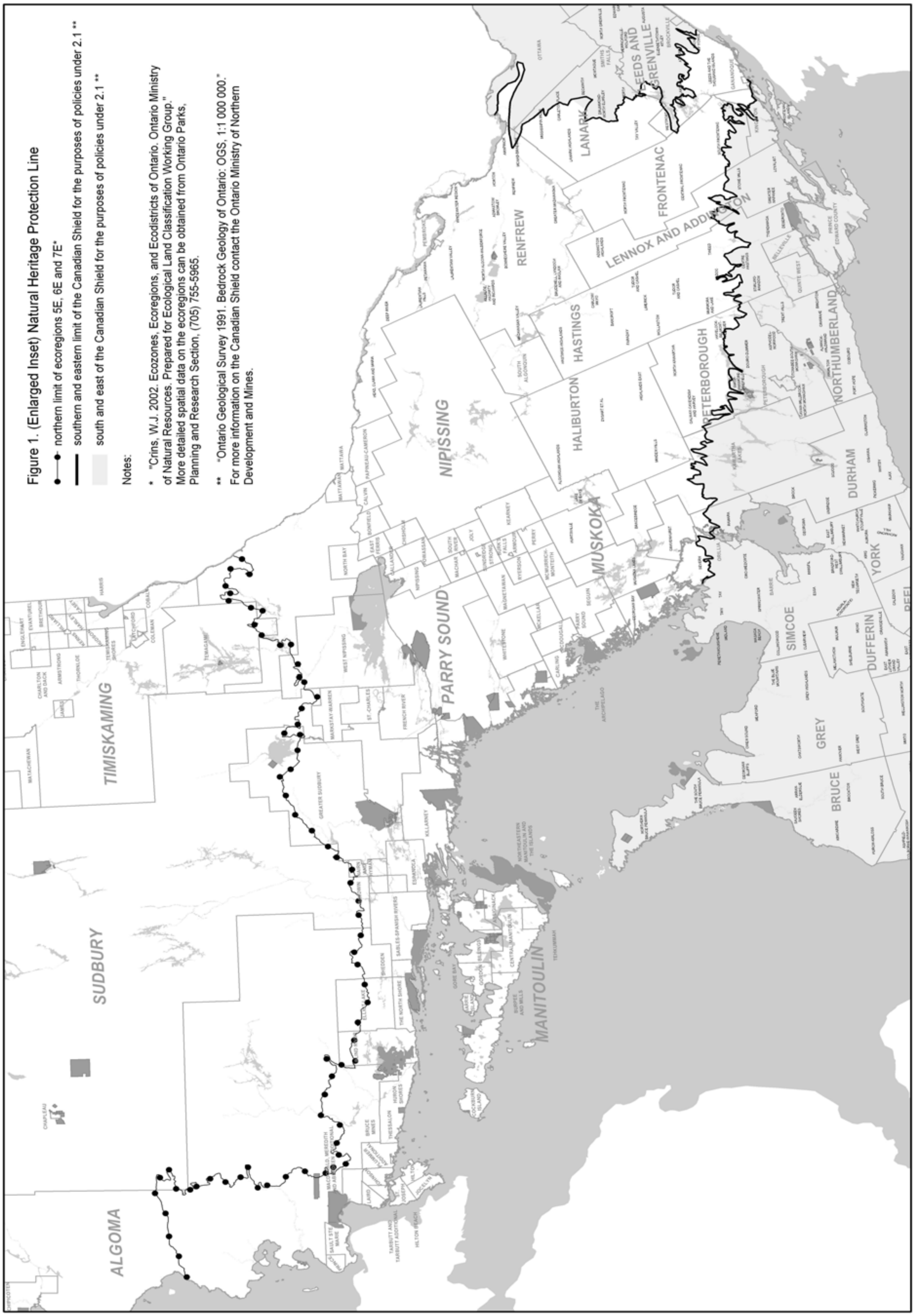
Figure 1. (Enlarged Inset) Natural Heritage Protection Line
northern limit of ecoregions 5E, 6E and 7E*
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ALGOMA
SUDBURY
TIMISKAMING
NIPISSING
PARRY SOUND
MUSKOKA
HALIBURTON
HASTINGS
RENFREW
LENNOX AND ADDINGTON
FRONTENAC
LANARK
LEEDS AND GRENVILLE
PETERBOROUGH
NORTHUMBERLAND
DURHAM
YORK
SIMCOE
DUFFERIN
GREY
BRUCE
MANITOULIN

6.0 DEFINITIONS

Access standards: means methods or procedures to ensure safe vehicular and pedestrian movement, and access for the maintenance and repair of protection works, during times of *flooding hazards*, *erosion hazards* and/or *other water-related hazards*.

Adjacent lands: means
a) for the purposes of policy 2.1, those lands contiguous to a specific *natural heritage feature or area* where it is likely that *development* or *site alteration* would have a *negative impact* on the feature or area. The extent of the *adjacent lands* may be recommended by the Province or based on municipal approaches which achieve the same objectives; and
b) for the purposes of policy 2.6.3, those lands contiguous to a *protected heritage property* or as otherwise defined in the municipal official plan.

Adverse effects: as defined in the *Environmental Protection Act*, means one or more of:
a) impairment of the quality of the natural environment for any use that can be made of it;
b) injury or damage to property or plant or animal life;
c) harm or material discomfort to any person;
d) an adverse effect on the health of any person;
e) impairment of the safety of any person;
f) rendering any property or plant or animal life unfit for human use;
g) loss of enjoyment of normal use of property; and
h) interference with normal conduct of business.

Affordable: means
a) in the case of ownership housing, the least expensive of:
   1. housing for which the purchase price results in annual accommodation costs which do not exceed 30 percent of gross annual household income for *low and moderate income households*; or
   2. housing for which the purchase price is at least 10 percent below the average purchase price of a resale unit in the *regional market area*;
b) in the case of rental housing, the least expensive of:
   1. a unit for which the rent does not exceed 30 percent of gross annual household income for *low and moderate income households*; or
   2. a unit for which the rent is at or below the average market rent of a unit in the *regional market area*.

Agricultural uses: means the growing of crops, including nursery and horticultural crops; raising of livestock; raising of other animals for food, fur or fibre, including poultry and fish; aquaculture; apiaries; agro-forestry; maple syrup production; and associated on-farm buildings and structures, including accommodation for full-time farm labour when the size and nature of the operation requires additional employment.

Agriculture-related uses: means those farm-related commercial and farm-related industrial uses that are small scale and directly related to the farm operation and are required in close proximity to the farm operation.

Airports: means all Ontario airports, including designated lands for future airports, with Noise Exposure Forecast (NEF)/Noise Exposure Projection (NEP) mapping.

Alternative energy systems: means sources of energy or energy conversion processes that significantly reduce the amount of harmful emissions to the environment (air, earth and water) when compared to conventional energy systems.

Archaeological resources: includes artifacts, archaeological sites and marine archaeological sites. The identification and evaluation of such resources are based upon archaeological fieldwork undertaken in accordance with the *Ontario Heritage Act*.

Areas of archaeological potential: means areas with the likelihood to contain *archaeological resources*. Criteria for determining archaeological potential are established by the Province, but municipal approaches which achieve the same objectives may also be used. Archaeological potential is confirmed through archaeological fieldwork undertaken in accordance with the *Ontario Heritage Act*.

Areas of mineral potential: means areas favourable to the discovery of *mineral deposits* due to geology, the presence of known *mineral deposits* or other technical evidence.

Areas of natural and scientific interest (ANSI): means areas of land and water containing natural landscapes or features that have been identified as having life science or earth science values related to protection, scientific study or education.

Areas of petroleum potential: means areas favourable to the discovery of *petroleum resources* due to geology, the presence of known *petroleum resources* or other technical evidence.

Brownfield sites: means undeveloped or previously developed properties that may be contaminated. They are usually, but not exclusively, former industrial or commercial properties that may be underutilized, derelict or vacant.

Built heritage resources: means one or more *significant* buildings, structures, monuments, installations or remains associated with architectural, cultural, social, political, economic or military history and identified as being important to a community. These resources may be identified through designation or heritage conservation easement under the *Ontario Heritage Act*, or listed by local, provincial or federal jurisdictions.

Coastal wetland: means

a) any *wetland* that is located on one of the Great Lakes or their connecting channels (Lake St. Clair, St. Mary's, St. Clair, Detroit, Niagara and St. Lawrence Rivers); or
b) any other *wetland* that is on a tributary to any of the above-specified water bodies and lies, either wholly or in part, downstream of a line located 2 kilometres upstream of the 1:100 year floodline (plus wave run-up) of the large water body to which the tributary is connected.

Comprehensive review: means

a) for the purposes of policies 1.1.3.9 and 1.3.2, an official plan review which is initiated by a planning authority, or an official plan amendment which is initiated or adopted by a planning authority, which:
    1. is based on a review of population and growth projections and which reflect projections and allocations by upper-tier municipalities and *provincial plans*, where applicable; considers alternative directions for growth; and determines how best to accommodate this growth while protecting provincial interests;
    2. utilizes opportunities to accommodate projected growth through *intensification* and *redevelopment*;
    3. confirms that the lands to be developed do not comprise *specialty crop areas* in accordance with policy 2.3.2;
    4. is integrated with planning for *infrastructure* and *public service facilities*; and
    5. considers cross-jurisdictional issues.
b) for the purposes of policy 1.1.5, means a review undertaken by a planning authority or comparable body which:
    1. addresses long-term population projections, *infrastructure* requirements and related matters;
    2. confirms that the lands to be developed do not comprise *specialty crop areas* in accordance with policy 2.3.2; and
    3. considers cross-jurisdictional issues.

Conserved: means the identification, protection, use and/or management of cultural heritage and archaeological resources in such a way that their heritage values, attributes and integrity are retained. This may be addressed through a conservation plan or heritage impact assessment.

Cultural heritage landscape: means a defined geographical area of heritage significance which has been modified by human activities and is valued by a community. It involves a grouping(s) of individual heritage features such as structures, spaces, archaeological sites and natural elements, which together form a significant type of heritage form, distinctive from that of its constituent elements or parts. Examples may include, but are not limited to, heritage conservation districts designated under the *Ontario Heritage Act*; and villages, parks, gardens, battlefields, mainstreets and neighbourhoods, cemeteries, trailways and industrial complexes of cultural heritage value.

Defined portions of the one hundred year flood level along connecting channels: means those areas which are critical to the conveyance of the flows associated with the *one hundred year flood level* along the St. Mary's, St. Clair, Detroit, Niagara and St. Lawrence Rivers, where *development* or *site alteration* will create *flooding hazards*, cause updrift and/or downdrift impacts and/or cause adverse environmental impacts.

Deposits of mineral aggregate resources: means an area of identified *mineral aggregate resources*, as delineated in Aggregate Resource Inventory Papers or comprehensive studies prepared using evaluation procedures established by the Province for surficial and bedrock resources, as amended from time to time, that has a sufficient quantity and quality to warrant present or future extraction.

Designated and available: for the purposes of policy 1.4.1(a), means lands designated in the official plan for urban residential use. For municipalities where more detailed official plan policies (e.g., secondary plans) are required before development applications can be considered for approval, only lands that have commenced the more detailed planning process are considered to be designated for the purposes of this definition.

Designated growth areas: means lands within *settlement areas* designated in an official plan for growth over the long-term planning horizon provided in policy 1.1.2, but which have not yet been fully developed. *Designated growth areas* include lands which are *designated and available* for residential growth in accordance with policy 1.4.1(a), as well as lands required for employment and other uses.

Designated vulnerable area: means areas defined as vulnerable, in accordance with provincial standards, by virtue of their importance as a drinking water source that may be impacted by activities or events.

Development: means the creation of a new lot, a change in land use, or the construction of buildings and structures, requiring approval under the *Planning Act*, but does not include:

a) activities that create or maintain *infrastructure* authorized under an environmental assessment process;
b) works subject to the *Drainage Act*; or
c) for the purposes of policy 2.1.3(b), underground or surface mining of *minerals* or advanced exploration on mining lands in *significant areas of mineral potential* in Ecoregion 5E, where advanced exploration has the same meaning as under the *Mining Act*. Instead, those matters shall be subject to policy 2.1.4(a).

Dynamic beach hazard: means areas of inherently unstable accumulations of shoreline sediments along the *Great Lakes - St. Lawrence River System* and *large inland lakes*, as identified by provincial standards, as amended from time to time. The *dynamic beach hazard* limit consists of the *flooding hazard* limit plus a dynamic beach allowance.

Ecological function: means the natural processes, products or services that living and non-living environments provide or perform within or between species, ecosystems and landscapes. These may include biological, physical and socio-economic interactions.

Employment area: means those areas designated in an official plan for clusters of business and economic activities including, but not limited to, manufacturing, warehousing, offices, and associated retail and ancillary facilities.

Endangered species: means a species that is listed or categorized as an "Endangered Species" on the Ontario Ministry of Natural Resources' official species at risk list, as updated and amended from time to time.

Erosion hazard: means the loss of land, due to human or natural processes, that poses a threat to life and property. The *erosion hazard* limit is determined using considerations that include the 100 year erosion rate (the average annual rate of recession extended over an one hundred year time span), an allowance for slope stability, and an erosion/erosion access allowance.

Fish: means fish, which as defined in S.2 of the *Fisheries Act*, c. F-14, as amended, includes fish, shellfish, crustaceans, and marine animals, at all stages of their life cycles.

Fish habitat: as defined in the *Fisheries Act*, c. F-14**,** means spawning grounds and nursery, rearing, food supply, and migration areas on which *fish* depend directly or indirectly in order to carry out their life processes.

Flood fringe: for *river, stream and small inland lake systems*, means the outer portion of the *flood plain* between the *floodway* and the *flooding hazard* limit. Depths and velocities of flooding are generally less severe in the flood fringe than those experienced in the *floodway*.

Flood plain: for *river stream, and small inland lake systems*, means the area, usually low lands adjoining a watercourse, which has been or may be subject to *flooding hazards.*

Flooding hazard: means the inundation, under the conditions specified below, of areas adjacent to a shoreline or a river or stream system and not ordinarily covered by water:

a) Along the shorelines of the *Great Lakes - St. Lawrence River System* and *large inland lakes*, the *flooding hazard* limit is based on the *one hundred year flood level* plus an allowance for *wave uprush* and *other water-related hazards*;
b) Along *river, stream and small inland lake systems*, the *flooding hazard* limit is the greater of:
    1. the flood resulting from the rainfall actually experienced during a major storm such as the Hurricane Hazel storm (1954) or the

Timmins storm (1961), transposed over a specific watershed and combined with the local conditions, where evidence suggests that the storm event could have potentially occurred over watersheds in the general area;

2. the *one hundred year flood*; and
3. a flood which is greater than 1. or 2. which was actually experienced in a particular watershed or portion thereof as a result of ice jams and which has been approved as the standard for that specific area by the Minister of Natural Resources;

except where the use of the *one hundred year flood* or the actually experienced event has been approved by the Minister of Natural Resources as the standard for a specific watershed (where the past history of flooding supports the lowering of the standard).

Floodproofing standard: means the combination of measures incorporated into the basic design and/or construction of buildings, structures, or properties to reduce or eliminate *flooding hazards*, *wave uprush* and *other water-related hazards* along the shorelines of the *Great Lakes - St. Lawrence River System* and *large inland lakes*, and *flooding hazards* along *river, stream* and *small inland lake systems*.

Floodway: for *river, stream and small inland lake systems*, means the portion of the *flood plain* where *development* and *site alteration* would cause a danger to public health and safety or property damage.

Where the one zone concept is applied, the *floodway* is the entire contiguous *flood plain*.

Where the two zone concept is applied, the *floodway* is the contiguous inner portion of the *flood plain*, representing that area required for the safe passage of flood flow and/or that area where flood depths and/or velocities are considered to be such that they pose a potential threat to life and/or property damage. Where the two zone concept applies, the outer portion of the *flood plain* is called the *flood fringe*.

Great Lakes - St. Lawrence River System: means the major water system consisting of Lakes Superior, Huron, St. Clair, Erie and Ontario and their connecting channels, and the St. Lawrence River within the boundaries of the Province of Ontario.

Ground water feature: refers to water-related features in the earth's subsurface, including recharge/discharge areas, water tables, aquifers and unsaturated zones that can be defined by surface and subsurface hydrogeologic investigations.

Hazardous lands: means property or lands that could be unsafe for development due to naturally occurring processes. Along the shorelines of the *Great Lakes - St. Lawrence River System*, this means the land, including that covered by water, between the international boundary, where applicable, and the furthest landward limit of the *flooding hazard, erosion hazard* or *dynamic beach hazard* limits. Along the shorelines of *large inland lakes*, this means the land, including that covered by water, between a defined offshore distance or depth and the furthest landward limit of the *flooding hazard, erosion hazard* or *dynamic beach hazard* limits. Along *river, stream and small inland lake systems*, this means the land, including that covered by water, to the furthest landward limit of the *flooding hazard* or *erosion hazard* limits.

Hazardous sites: means property or lands that could be unsafe for *development* and *site alteration* due to naturally occurring hazards. These may include unstable soils (sensitive marine clays [leda], organic soils) or unstable bedrock (karst topography).

Hazardous substances: means substances which, individually, or in combination with other substances, are normally considered to pose a danger to public health, safety and the environment. These substances generally include a wide array of materials that are toxic, ignitable, corrosive, reactive, radioactive or pathological.

Heritage attributes: means the principal features, characteristics, context and appearance that contribute to the cultural heritage significance of a *protected heritage property*.

Hydrologic function: means the functions of the hydrological cycle that include the occurrence, circulation, distribution and chemical and physical properties of water on the surface of the land, in the soil and underlying rocks, and in the atmosphere, and water's interaction with the environment including its relation to living things.

Individual on-site sewage services: means individual, autonomous sewage disposal systems within the meaning of s.8.1.2, O.Reg. 403/97, under the *Building Code Act, 1992* that are owned, operated and managed by the owner of the property upon which the system is located.

Individual on-site water services: means individual, autonomous water supply systems that are owned, operated and managed by the owner of the property upon which the system is located.

Infrastructure: means physical structures (facilities and corridors) that form the foundation for development. *Infrastructure* includes: sewage and water systems, septage treatment systems, waste management systems, electric power generation and transmission, communications/telecommunications, transit and transportation corridors and facilities, oil and gas pipelines and associated facilities.

Intensification: means the development of a property, site or area at a higher density than currently exists through:

a) *redevelopment*, including the reuse of *brownfield sites*;
b) the development of vacant and/or underutilized lots within previously developed areas;
c) infill development; and
d) the expansion or conversion of existing buildings.

Large inland lakes: means those waterbodies having a surface area of equal to or greater than 100 square kilometres where there is not a measurable or predictable response to a single runoff event.

Legal or technical reasons: for the purposes of policy 2.3.4.2, means severances for purposes such as easements, corrections of deeds, quit claims, and minor boundary adjustments, which do not result in the creation of a new lot.

Low and moderate income households: means

a) in the case of ownership housing, households with incomes in the lowest 60 percent of the income distribution for the *regional market area*; or
b) in the case of rental housing, households with incomes in the lowest 60 percent of the income distribution for renter households for the *regional market area*.

Mine hazard: means any feature of a mine as defined under the *Mining Act*, or any related disturbance of the ground that has not been rehabilitated.

Minerals: means metallic minerals and non-metallic minerals as herein defined, but does not include *mineral aggregate resources* or *petroleum resources*.

Metallic minerals means those minerals from which metals (e.g. copper, nickel, gold) are derived.

Non-metallic minerals means those minerals that are of value for intrinsic properties of the minerals themselves and not as a source of metal. They are generally synonymous with industrial minerals (e.g. asbestos, graphite, kyanite, mica, nepheline syenite, salt, talc, and wollastonite).

Mineral aggregate operation: means

a) lands under license or permit, other than for *wayside pits and quarries*, issued in accordance with the *Aggregate Resources Act*, or successors thereto;
b) for lands not designated under the *Aggregate Resources Act*, established pits and quarries that are not in contravention of municipal zoning by-laws and including adjacent land under agreement with or owned by the operator, to permit continuation of the operation; and
c) associated facilities used in extraction, transport, beneficiation, processing or recycling of *mineral aggregate resources* and derived products such as asphalt and concrete, or the production of secondary related products.

Mineral aggregate resources: means gravel, sand, clay, earth, shale, stone, limestone, dolostone, sandstone, marble, granite, rock or other material prescribed under the *Aggregate Resources Act* suitable for construction, industrial, manufacturing and maintenance purposes but does not include metallic ores, asbestos, graphite, kyanite, mica, nepheline syenite, salt, talc, wollastonite, mine tailings or other material prescribed under the *Mining Act*.

Mineral deposits: means areas of identified *minerals* that have sufficient quantity and quality based on specific geological evidence to warrant present or future extraction.

Mineral mining operation: means mining operations and associated facilities, or, past producing mines with remaining mineral development potential that have not been permanently rehabilitated to another use.

Minimum distance separation formulae: means formulae developed by the Province to separate uses so as to reduce incompatibility concerns about odour from livestock facilities.

Multi-modal transportation system: means a transportation system which may include several forms of transportation such as automobiles, walking, trucks, cycling, buses, rapid transit, rail (such as commuter and freight), air and marine.

Municipal sewage services: means a sewage works within the meaning of Section 1 of the *Ontario Water Resources Act* that is owned or operated by a municipality.

Municipal water services: means a municipal drinking-water system within the meaning of Section 2 of the *Safe Drinking Water Act, 2002.*

Natural heritage features and areas: means features and areas, including *significant wetlands*, *significant coastal wetlands*, *fish habitat*, *significant woodlands* south and east of the Canadian Shield, *significant valleylands* south and east of the Canadian Shield, *significant* habitat of *endangered species* and *threatened species*, *significant wildlife habitat*, and *significant areas of natural and scientific interest*, which are important for their environmental and social values as a legacy of the natural landscapes of an area.

Natural heritage system: means a system made up of *natural heritage features and areas*, linked by natural corridors which are necessary to maintain biological and geological diversity, natural functions, viable populations of indigenous species and ecosystems. These systems can include lands that have been restored and areas with the potential to be restored to a natural state.

Negative impacts: means
a) in regard to policy 2.2, degradation to the *quality and quantity of water*, *sensitive surface water features* and *sensitive ground water features*, and their related *hydrologic functions*, due to single, multiple or successive *development* or *site alteration* activities;
b) in regard to *fish habitat*, the harmful alteration, disruption or destruction of *fish habitat*, except where, in conjunction with the appropriate authorities, it has been authorized under the *Fisheries Act*, using the guiding principle of no net loss of productive capacity; and
c) in regard to other *natural heritage features and areas*, degradation that threatens the health and integrity of the natural features or *ecological functions* for which an area is identified due to single, multiple or successive *development* or *site alteration* activities.

Normal farm practices: means a practice, as defined in the *Farming and Food Production Protection Act, 1998,* that is conducted in a manner consistent with proper and acceptable customs and standards as established and followed by similar agricultural operations under similar circumstances; or makes use of innovative technology in a manner consistent with proper advanced farm management practices. Normal farm practices shall be consistent with the *Nutrient Management Act, 2002* and regulations made under that Act.

Oil, gas and salt hazards: means any feature of a well or work as defined under the *Oil, Gas and Salt Resources Act*, or any related disturbance of the ground that has not been rehabilitated.

One hundred year flood: for *river, stream and small inland lake systems*, means that flood, based on an analysis of precipitation, snow melt, or a combination thereof, having a return period of 100 years on average, or having a 1% chance of occurring or being exceeded in any given year.

One hundred year flood level: means
a) for the shorelines of the Great Lakes, the peak instantaneous stillwater level, resulting from combinations of mean monthly lake levels and wind setups, which has a 1% chance of being equalled or exceeded in any given year;
b) in the connecting channels (St. Mary's, St. Clair, Detroit, Niagara and St. Lawrence Rivers), the peak instantaneous stillwater level which has a 1% chance of being equalled or exceeded in any given year; and
c) for large inland lakes, lake levels and wind setups that have a 1% chance of being equalled or exceeded in any given year, except that, where sufficient water level records do not exist, the one hundred year flood level is based on the highest known water level and wind setups.

Other water-related hazards: means water-associated phenomena other than *flooding hazards* and *wave uprush* which act on shorelines. This includes, but is not limited to ship-generated waves, ice piling and ice jamming.

Partial services: means
a) *municipal sewage services* or *private communal sewage services* and *individual on-site water services*; or
b) *municipal water services* or *private communal water services* and *individual on-site sewage services*.

Petroleum resource operations: means oil, gas and brine wells, and associated facilities, oil field brine disposal wells and associated facilities, and facilities for the underground storage of natural gas and other hydrocarbons.

Petroleum resources: means oil, gas, and brine resources which have been identified through exploration and verified by preliminary drilling or other forms of investigation. This may include sites of former operations where resources are still present or former sites that may be converted to underground storage for natural gas or other hydrocarbons.

Planned corridors: means corridors identified through *provincial plans* or preferred alignment(s) determined through the *Environmental Assessment Act* process which are required to meet projected needs.

Portable asphalt plant: means a facility
a) with equipment designed to heat and dry aggregate and to mix aggregate with bituminous asphalt to produce asphalt paving material, and includes stockpiling and storage of bulk materials used in the process; and
b) which is not of permanent construction, but which is to be dismantled at the completion of the construction project.

Portable concrete plant: means a building or structure
a) with equipment designed to mix cementing materials, aggregate, water and admixtures to produce concrete, and includes stockpiling and storage of bulk materials used in the process; and
b) which is not of permanent construction, but which is designed to be dismantled at the completion of the construction project.

Prime agricultural area: means areas where *prime agricultural lands* predominate. This includes: areas of *prime agricultural lands* and associated Canada Land Inventory Class 4-7 soils; and additional areas where there is a local concentration of farms which exhibit characteristics of ongoing agriculture. *Prime agricultural areas* may be identified by the Ontario Ministry of Agriculture and Food using evaluation procedures established by the Province as amended from time to time, or may also be identified through an alternative agricultural land evaluation system approved by the Province.

Prime agricultural land: means land that includes *specialty crop areas* and/or Canada Land Inventory Classes 1, 2, and 3 soils, in this order of priority for protection.

Private communal sewage services: means a sewage works within the meaning of Section 1 of the *Ontario Water Resources Act* that serves six or more lots or private residences and is not owned by a municipality.

Private communal water services: means a non-municipal drinking-water system within the meaning of Section 2 of the *Safe Drinking Water Act, 2002* that serves six or more lots or private residences.

Protected heritage property: means real property designated under Parts IV, V or VI of the *Ontario Heritage Act*; heritage conservation easement property under Parts II or IV of the *Ontario Heritage Act*; and property that is the subject of a covenant or agreement between the owner of a property and a conservation body or level of government, registered on title and executed with the primary purpose of preserving, conserving and maintaining a cultural heritage feature or resource, or preventing its destruction, demolition or loss.

Protection works standards: means the combination of non-structural or structural works and allowances for slope stability and flooding/erosion to reduce the damage caused by *flooding hazards*, *erosion hazards* and *other water-related hazards*, and to allow access for their maintenance and repair.

Provincial and federal requirements: means
a) in regard to policy 1.8.3, legislation and policies administered by the federal or provincial governments for the purpose of protecting the environment from potential impacts associated with energy facilities and ensuring that the necessary approvals are obtained; and
b) in regard to policy 2.1.5, legislation and policies administered by the federal or provincial governments for the purpose of the protection of *fish* and *fish habitat*, and related, scientifically established standards such as water quality criteria for protecting lake trout populations.

Provincial plan: means a plan approved by the Lieutenant Governor in Council or the Minister of Municipal Affairs and Housing, but does not include municipal official plans.

Public service facilities: means land, buildings and structures for the provision of programs and services provided or subsidized by a government or other body, such as social assistance, recreation, police and fire protection, health and educational programs, and cultural services. *Public service facilities* do not include *infrastructure.*

Quality and quantity of water: is measured by indicators such as minimum base flow, depth to water table, aquifer pressure, oxygen levels, suspended solids, temperature, bacteria, nutrients and hazardous contaminants, and hydrologic regime.

Recreation: means leisure time activity undertaken in built or natural settings for purposes of physical activity, health benefits, sport participation and skill development, personal enjoyment, positive social interaction and the achievement of human potential.

Redevelopment: means the creation of new units, uses or lots on previously developed land in existing communities, including *brownfield sites*.

Regional market area: refers to an area, generally broader than a lower-tier municipality, that has a high degree of social and economic interaction. In southern Ontario, the upper or single-tier municipality will normally serve as the *regional market area*. Where a *regional market area* extends significantly beyond upper or single-tier boundaries, it may include a combination of upper, single and/or lower-tier municipalities.

Renewable energy systems: means the production of electrical power from an energy source that is renewed by natural processes including, but not limited to, wind, water, a biomass resource or product, or solar and geothermal energy.

Reserve sewage system capacity: means design or planned capacity in a centralized waste water treatment facility which is not yet committed to existing or approved development. For the purposes of policy 1.6.4.1(e), reserve capacity for *private communal sewage services* and *individual on-site sewage services* is considered sufficient if the hauled sewage from the development can be treated or disposed of at sites approved under the *Environmental Protection Act* or the *Ontario Water Resources Act*, but not by land-applying untreated, hauled sewage.

Reserve water system capacity: means design or planned capacity in a centralized water treatment facility which is not yet committed to existing or approved development.

Residence surplus to a farming operation: means an existing farm residence that is rendered surplus as a result of farm consolidation (the acquisition of additional farm parcels to be operated as one farm operation).

Residential intensification: means intensification of a property, site or area which results in a net increase in residential units or accommodation and includes:

a) redevelopment, including the redevelopment of *brownfield sites*;
b) the development of vacant or underutilized lots within previously developed areas;
c) infill development;
d) the conversion or expansion of existing industrial, commercial and institutional buildings for residential use; and
e) the conversion or expansion of existing residential buildings to create new residential units or accommodation, including accessory apartments, secondary suites and rooming houses.

River, stream and small inland lake systems: means all watercourses, rivers, streams, and small inland lakes or waterbodies that have a measurable or predictable response to a single runoff event.

Rural areas: means lands in the rural area which are located outside *settlement areas* and which are outside *prime agricultural areas.*

Secondary uses: means uses secondary to the principal use of the property, including but not limited to, home occupations, home industries, and uses that produce value-added agricultural products from the farm operation on the property.

Sensitive: in regard to *surface water features* and *ground water features*, means areas that are particularly susceptible to impacts from activities or events including, but not limited to, water withdrawals, and additions of pollutants.

Sensitive land uses: means buildings, amenity areas, or outdoor spaces where routine or normal activities occurring at reasonably expected times would experience one or more *adverse effects* from contaminant discharges generated by a nearby major facility. *Sensitive land uses* may be a part of the natural or built environment. Examples may include, but are not limited to: residences, day care centres, and educational and health facilities.

Settlement areas: means urban areas and rural settlement areas within municipalities (such as cities, towns, villages and hamlets) that are:

a) built up areas where development is concentrated and which have a mix of land uses; and
b) lands which have been designated in an official plan for development over the long term planning horizon provided for in policy 1.1.2. In

cases where land in *designated growth areas* is not available, the *settlement area* may be no larger than the area where development is concentrated.

Sewage and water services: includes *municipal sewage services* and *municipal water services*, *private communal sewage services* and *private communal water services*, *individual on-site sewage services* and *individual on-site water services*, and *partial services*.

Significant: means

a) in regard to *wetlands*, *coastal wetlands* and *areas of natural and scientific interest*, an area identified as provincially significant by the Ontario Ministry of Natural Resources using evaluation procedures established by the Province, as amended from time to time;
b) in regard to the habitat of *endangered species* and *threatened species*, means the habitat, as approved by the Ontario Ministry of Natural Resources, that is necessary for the maintenance, survival, and/or the recovery of naturally occurring or reintroduced populations of *endangered species* or *threatened species*, and where those areas of occurrence are occupied or habitually occupied by the species during all or any part(s) of its life cycle;
c) in regard to *woodlands*, an area which is ecologically important in terms of features such as species composition, age of trees and stand history; functionally important due to its contribution to the broader landscape because of its location, size or due to the amount of forest cover in the planning area; or economically important due to site quality, species composition, or past management history;
d) in regard to other features and areas in policy 2.1, ecologically important in terms of features, functions, representation or amount, and contributing to the quality and diversity of an identifiable geographic area or *natural heritage system*;
e) in regard to *mineral* potential, means an area identified as provincially significant through comprehensive studies prepared using evaluation procedures established by the Province, as amended from time to time, such as the Provincially Significant Mineral Potential Index;
f) in regard to potential for *petroleum resources*, means an area identified as provincially significant through comprehensive studies prepared using evaluation procedures established by the Province, as amended from time to time; and
g) in regard to cultural heritage and archaeology, resources that are valued for the important contribution they make to our understanding of the history of a place, an event, or a people.

Criteria for determining significance for the resources identified in sections (c)-(g) are recommended by the Province, but municipal approaches that achieve or exceed the same objective may also be used.

While some significant resources may already be identified and inventoried by official sources, the significance of others can only be determined after evaluation.

Site alteration: means activities, such as grading, excavation and the placement of fill that would change the landform and natural vegetative characteristics of a site.

For the purposes of policy 2.1.3(b), *site alteration* does not include underground or surface mining of *minerals* or advanced exploration on mining lands in *significant areas of mineral potential* in Ecoregion 5E, where advanced exploration has the same meaning as in the *Mining Act*. Instead, those matters shall be subject to policy 2.1.4(a).

Special needs: means any housing, including dedicated facilities, in whole or in part, that is used by people who have specific needs beyond economic needs, including but not limited to, needs such as mobility requirements or support functions required for daily living. Examples of *special needs* housing may include, but are not limited to, housing for persons with disabilities such as physical, sensory or mental health disabilities, and housing for the elderly.

Special policy area: means an area within a community that has historically existed in the *flood plain* and where site-specific policies, approved by both the Ministers of Natural Resources and Municipal Affairs and Housing, are intended to provide for the continued viability of existing uses (which are generally on a small scale) and address the significant social and economic hardships to the community that would result from strict adherence to provincial policies concerning *development*. The criteria and procedures for approval are established by the Province.

A *Special Policy Area* is not intended to allow for new or intensified development and site alteration, if a community has feasible opportunities for development outside the *flood plain.*

Specialty crop area: means areas designated using evaluation procedures established by the province, as amended from time to time, where specialty crops such as tender fruits (peaches, cherries, plums), grapes, other fruit crops, vegetable crops, greenhouse crops, and crops from agriculturally developed organic soil lands are predominantly grown, usually resulting from:

a) soils that have suitability to produce specialty crops, or lands that are subject to special climatic conditions, or a combination of both; and/or
b) a combination of farmers skilled in the production of specialty crops, and of capital investment in related facilities and services to produce, store, or process specialty crops.

Surface water feature: refers to water-related features on the earth's surface, including headwaters, rivers, stream channels, inland lakes, seepage areas, recharge/discharge areas, springs, wetlands, and associated riparian lands that can be defined by their soil moisture, soil type, vegetation or topographic characteristics.

Threatened species: means a species that is listed or categorized as a "Threatened Species" on the Ontario Ministry of Natural Resources' official species at risk list, as updated and amended from time to time.

Transportation systems: means a system consisting of corridors and rights-of way for the movement of people and goods, and associated transportation facilities including transit stops and stations, cycle lanes, bus lanes, high occupancy vehicle lanes, rail facilities, park'n'ride lots, service centres, rest stops, vehicle inspection stations, intermodal terminals, harbours, and associated facilities such as storage and maintenance.

Valleylands: means a natural area that occurs in a valley or other landform depression that has water flowing through or standing for some period of the year.

Vulnerable: means surface and groundwater that can be easily changed or impacted by activities or events, either by virtue of their vicinity to such activities or events or by permissive pathways between such activities and the surface and/or groundwater.

Waste management system: means sites and facilities to accommodate solid waste from one or more municipalities and includes landfill sites, recycling facilities, transfer stations, processing sites and hazardous waste depots.

Watershed: means an area that is drained by a river and its tributaries.

Wave uprush: means the rush of water up onto a shoreline or structure following the breaking of a wave; the limit of wave uprush is the point of furthest landward rush of water onto the shoreline.

Wayside pits and quarries: means a temporary pit or quarry opened and used by or for a public authority solely for the purpose of a particular project or contract of road construction and not located on the road right-of-way.

Wetlands: means lands that are seasonally or permanently covered by shallow water, as well as lands where the water table is close to or at the surface. In either case the presence of abundant water has caused the formation of hydric soils and has favoured the dominance of either hydrophytic plants or water tolerant plants. The four major types of wetlands are swamps, marshes, bogs and fens.

Periodically soaked or wet lands being used for agricultural purposes which no longer exhibit wetland characteristics are not considered to be wetlands for the purposes of this definition.

Wildlife habitat: means areas where plants, animals and other organisms live, and find adequate amounts of food, water, shelter and space needed to sustain their populations. Specific wildlife habitats of concern may include areas where species concentrate at a vulnerable point in their annual or life cycle; and areas which are important to migratory or non-migratory species.

Woodlands: means treed areas that provide environmental and economic benefits to both the private landowner and the general public, such as erosion prevention, hydrological and nutrient cycling, provision of clean air and the long-term storage of carbon, provision of wildlife habitat, outdoor recreational opportunities, and the sustainable harvest of a wide range of woodland products. *Woodlands* include treed areas, woodlots or forested areas and vary in their level of significance at the local, regional and provincial levels.

Notes

STAKEHOLDER AND COMMUNITY CONSULTATION

1.0 INTRODUCTION

Hydro One has completed the initial stage of its consultation process for the project. This schedule describes the consultation approach, identifies key stakeholders and summarizes input received and results to date. This section will also outline the consultation approach which will be carried out as part of the EA and Section 92 processes. A separate exhibit, Exhibit B, Tab 6, Schedule 7, addresses the Aboriginal engagement process.

During this initial consultation stage, Hydro One has focused on briefing upper- and lower-tier municipalities affected by the project. Hydro One intends to continue consultation with a broader range of audiences with the primary objective of dealing directly with affected property owners. Hydro One will also provide timely and regular project updates and opportunities for feedback for the public and key stakeholders including municipal and county/regional officials.

2.0 CONSULTATION APPROACH

The result of the consultation provides valuable input to the EA and OEB review processes.

There are two key phases for the project: 1) the section 92 proceeding and EA Terms of Reference, which are expected to occur in parallel; and 2) the EA. Hydro One will be identifying and consulting with affected property owners and stakeholders who may have an interest in the proposed facilities during both these phases and the Section 92 application will be updated as required, based on the results of this consultation.

3.0 OBJECTIVES OF THE CONSULTATION PROCESS

The intent of the process is to inform affected property owners, stakeholders and the general public about the project, identify any issues, and develop project plans that address those issues, where appropriate. Based on consultations to date, a summary of the issues raised and how Hydro One intends to address them is included in this Schedule. This document will be updated with input obtained through Hydro One's ongoing consultation process.

3.1 Meetings with Municipal Staff

Prior to initiating the formal EA and filing the Section 92 Application, Hydro One met with senior administrative staff for all upper- and lower-tier municipalities potentially affected by the project. These meetings were held in December 2006 and January 2007. A summary of the issues raised at these meetings and how Hydro One intends to address them is included in Section 4 of this Schedule.

At these meetings, Hydro One and the OPA provided information on the project, including the need for the transmission reinforcement to support energy development in the Bruce area and the role of the OPA in determining the solution for delivering committed and potential generation from the Bruce area to meet the province's supply needs. The requirement for a Section 92 approval, EA approval and project timelines were also discussed. Hydro One also obtained contact information for local interest groups that would be included in the consultation process, as well as an understanding of local issues and potential concerns associated with the proposed transmission line.

Following is a list of meetings with senior municipal administrative and planning staff held in December 2006 and January 2007:

- County of Bruce
  - Municipality of Kincardine
  - Municipality of Brockton
- County of Grey
  - Town of Hanover
  - Municipality of West Grey
  - Township of Southgate
- Wellington County
  - Township of Wellington North
  - Town of Erin
- Dufferin County
  - Township of East Luther Grand Valley
  - Township of East Garafraxa
- Regional Municipality of Halton
  - Town of Halton Hills
  - Town of Milton

A summary of the issues identified at the above meetings can be found in Section 4 of this Schedule.

A Municipal Advisory Group is proposed as a forum for discussion of issues during key milestones of the project. Relevant issues will be incorporated into the project plans and this application will be updated as required. Municipal staff will also have access to all other consultation opportunities including public information centres, inter-active web-based information and one-on-one meetings as requested.

3.2 Meeting with Elected Officials

As part of the consultation process, Hydro One will provide information and formal written notification to mayors/reeves/wardens and MPPs whose municipalities and ridings are affected. These activities have been initiated and are planned to continue throughout the project as required. Issues raised and how Hydro One intends to address them will be tracked and reported at a future date.

Throughout the consultation process, Hydro One will ensure that elected officials at all levels are kept informed of project activities. They will be provided communications material and documents (e.g., ads and newsletters). Elected officials will also have access to other consultation opportunities, including public information centres, inter-active web-based information and one-on-one meetings as requested.

3.3 Meetings with Other Stakeholders

There are a number of agencies and interest groups who are expected to be interested and wish to be involved in this project. Hydro One is developing a stakeholder list to identify whom to contact and to determine the most appropriate way to involve them in the project. Participation by the following stakeholders is anticipated:

- Environment Canada
- Canadian Environmental Assessment Agency
- Fisheries and Oceans Canada
- Ministry of Agriculture, Food and Rural Affairs
- Ministry of Culture
- Ministry of Energy
- Ministry of Environment
- Ministry of Municipal Affairs and Housing

- Ministry of Transportation
- Ministry of Tourism
- Niagara Escarpment Commission
- Ontario Realty Corporation
- Oak Ridges Moraine and Greenbelt interest groups
- School Boards and Health Units
- Conservation Authorities
- Energy interest groups
- Environmental interest groups
- Local ratepayer groups
- Farm- related interest groups
- Others as identified during the project

Throughout the consultation process, all stakeholders will be kept informed of the project through the receipt of communication material (e.g., newspaper ads, flyers, newsletters and web site) and opportunities to obtain and review documents.

Since December 2006, Hydro One has had discussions with key provincial and federal government agencies to provide an overview of the project. The discussion of key issues and approval requirements will be ongoing with agencies and interest groups throughout the planning period. A Government Review Team normally composed of provincial ministry and agency representatives will examine the EA documentation at key milestones during the approvals process.

Meetings will be held with interest groups on an as-needed basis. To the extent appropriate, electronic discussion tools such as web seminars will be used.

3.4 Public Information Centres and Notification

Hydro One will use various methods to notify affected property owners, the local community and key stakeholders about the project and the planned public information centres (PICs). Newspaper ads will be placed in the local newspapers providing details about the project, the dates and locations for upcoming PICs, as well as a Hydro One contact name, toll-free 1-800 number and the project web site.

The project-specific web page at www.HydroOneNetworks.com\newprojects will be designed as an interactive portal for obtaining information and providing input. This web page will provide an overview of the project, access to downloadable information, responses to frequently asked questions and an opportunity to provide comment. The web page will be kept up to date as new information becomes available.

Newsletters will be distributed to all those on the project mailing list, which will include property owners (residential, farm and business) within a minimum of 500 metres of the corridor. The newsletters will serve as an invitation to PICs and a reminder of information available on the web site and will provide general project status information. Affected property owners will also be contacted on a one-on-one basis to discuss property issues and project timing.

Advance copies of the newspaper ad and newsletter will be provided to key public officials, including MPPs, local elected officials, and Chief Administrative Officers and senior planning officials of both upper- and lower-tier municipalities along the transmission corridor.

The first series of PICs will be held in late April and early May 2007 in the communities of Kincardine, Hanover, Southgate, East Luther Grand Valley, East Garafraxa, Erin and

Halton Hills. The number and location of the PICs are tailored to ensure access for all interested parties. The PICs will provide interested stakeholders with the opportunity to review project information and plans, provide input to Hydro One's planning process, and discuss their concerns with Hydro One's project team and OPA staff.

Visitors to the PICs will be provided with a comment form to complete. All comments received will be documented and responded to, and will become part of the EA documentation, and this Section 92 application will be updated as required.

4.0 SUMMARY OF KEY ISSUES TO-DATE AND HYDRO ONE RESPONSE:

Issue	Description of Issue	Response/Mitigation
4.1 Economic Development	Development at Bruce Power Complex is supported by many communities, particularly in Bruce County.	Transmission line is perceived as supporting the economic development and future prosperity in the area through further generation development.
4.2 Wind Power Developments	Both support and opposition for wind projects in the area.	Transmission line will facilitate generation developments, including wind, to meet provincial supply needs.
4.3 EA Process	Numerous EA processes underway in Bruce County by other proponents.	Work closely with other proponents in the area to ensure differentiation of generation and transmission projects and timelines are clear to the public.
4.4 Visual Impacts	Concerns relating to the visual impact of new set of transmission towers.	Hydro One will discuss tower type and placement with affected property owners. Tower placement will follow alignment of current towers to the extent possible to mitigate visual impact. Hydro One will discuss the proposed transmission line layout with affected property owners prior to the start of

Issue	Description of Issue	Response/Mitigation
		construction and will attempt to accommodate individual requests. Landscaping will be undertaken at selected locations along the right-of-way to enhance the appearance of the transmission corridor.
4.5 Impacts on Agricultural Activities	Impact of new towers on farming operations.	Hydro One will work with affected property owners to minimize the impact of the new structures on agricultural activities.
4.6 Property Compensation	Hydro One treatment of affected property owners.	During the section 92 proceedings, Hydro One will begin discussions with landowners. In order to meet the urgent in service timelines, Hydro One will be utilizing the expropriation process under the Ontario Energy Board Act and the Expropriations Act after receiving section 92 approval. Hydro One is committed to a consistent compensation treatment of affected property owners using market value principles. Hydro One's objective is to take the minimum amount of land from private ownership and out of agricultural production.
4.7 Construction Impacts	Concerns relating to potential property damage such as tile drains, underground services, and compaction of soils on agricultural properties. Concerns relating to the timing of construction	Hydro One will consult with affected property owners prior to the start of construction to identify potential impacts and mitigations. Prior notification will be given of any requirement to access the property for pre-construction work and Hydro One will inform affected owners of its construction schedule. Hydro One

Issue	Description of Issue	Response/Mitigation
	due to crop planting/ harvesting and regarding adequate notification prior to the commencement of work.	will make best efforts to schedule construction activities to minimize interference with farm operations. Hydro One will repair at its expense any damage caused to the owner's infrastructure or property, and when construction is complete will remediate any soil compaction that has occurred. Standard best practices will be followed to ensure typical construction disturbances (e.g., dust and noise) are minimized.
4.8 Loss of Farm Income	Concerns relating to loss of income during the construction phase	Hydro One will compensate farmers for loss of income resulting from construction activities related to the project.
4.9 Future Development Proposal	Concerns relating to impacts on major commercial/ industrial developments in Halton Region. The Town of Halton Hills has expressed concerns over tax revenue losses associated with two development proposals/plans immediately north of Highway 401.	Hydro One has met with developers and municipal staff in an effort to mitigate concerns. Hydro One has developed a technical solution that makes use of available land for a short section of the route on the west side of the existing transmission corridor in the vicinity of the planned developments. This solution is expected to mitigate the expressed concerns.
4.10 Electric and Magnetic Fields (EMFs)	Potential health effects associated with EMFs.	Information about EMFs will be available at the PICs, and is also available on Hydro One's web site at www.HydroOneNetworks.com. Health Canada current position on EMFs is that typical exposures present

Issue	Description of Issue	Response/Mitigation
		no known health risk. Further information is available on Health Canada's website: www.hc-sc.gc.ca. Hydro One provides on request EMF measurements at no charge to customers whose property is crossed by or abuts a Hydro One transmission corridor.

1

ABORIGINAL ENGAGEMENT PROCESS

1.0 INTRODUCTION

Hydro One recognizes the importance of engaging with First Nations and the Métis (the "Aboriginal Groups") regarding the new 500kV double circuit line from the Bruce Power Complex to Milton SS. This Schedule sets out Hydro One's process for engaging with the Aboriginal Groups who may have an interest in, or may be potentially affected by, the Project.

2.0 IDENTIFICATION OF THE ABORIGINAL GROUPS

Hydro One has identified, to date, a number of First Nations who may have an interest in, or may be potentially affected by, the project. They include the Chippewas of Saugeen, the Chippewas of Nawash, the Mississaugas of New Credit, and the Six Nations of the Grand River including the Haudenosaunee Six Nations Confederacy Council.

Hydro One has identified, to date, the following Métis Groups who may have an interest in, or may be potentially affected by, the project: the Georgian Bay Métis Council, the Grey Owen Sound Métis Council and the Saguingue Métis Council.

3.0 ENGAGEMENT PRINCIPLES FOR ABORIGINAL GROUPS

The following principles will guide Hydro One in its engagement with the Aboriginal Groups regarding the project:

- Engage with the Aboriginal Groups early in the project's application phase and continue such engagement throughout the project's regulatory approval process and also throughout the construction/in service phases;

- Provide the Aboriginal Groups with relevant information about the project in a timely and ongoing manner;
- In addition to providing regular project updates, share information, where requested, on the OEB's regulatory process and the EA process regarding the project;
- Provide the Aboriginal Groups with opportunities to identify issues and concerns, and ask questions, regarding the project;
- Respond to or address, as the case may be, the issues, concerns and questions raised by the Aboriginal Groups regarding the project and identify how such issues and concerns were considered by Hydro One, including any avoidance, mitigation or reduction in potential effects on the Aboriginal Groups as determined by Hydro One; and,
- Provide opportunities to participate in archaeological studies and to share the findings of those studies.

4.0 ENGAGEMENT PROCESS FOR ABORIGINAL GROUPS

Hydro One's engagement process for Aboriginal Groups is designed to provide relevant information on the project to the Aboriginal Groups in a timely manner and to respond to and consider issues, concerns or questions raised by the Aboriginal Groups in a clear and transparent manner throughout the completion of the regulatory approval processes (e.g., the EA process). Engagement with the Aboriginal Groups will include:

- Providing project-related information, including ensuring that all publicly available information is also made available to the Aboriginal Groups;

- Seeking relevant information from the Aboriginal Groups that may be applicable to the project's route, including information regarding archeological sites and sacred burial grounds;
- Offering information centers or meetings with the Aboriginal Groups to provide project-related information and to address any concerns, issues or questions about the project;
- Providing information, where requested, on the OEB's regulatory process and the EA process regarding the project;
- Giving consideration to all issues and concerns raised by the Aboriginal Groups and to how the project may affect the Aboriginal interests of the Aboriginal Groups, addressing any potentially affected Aboriginal interests, and communicating the results of such action clearly to the Aboriginal Groups; and
- Recording all forms of engagement with the Aboriginal Groups, including creating a list of concerns and issues raised by the Aboriginal Groups regarding the projects and Hydro One's responses thereto.

5.0 ENGAGEMENT TO DATE WITH ABORIGINAL GROUPS

Prior to the filing of this application, Hydro One has made initial contact with the Aboriginal Groups (with the exception of one of the Métis Groups) to discuss the proposed project and to engage with the Aboriginal Groups and provide them with information respecting the project. Preliminary meetings began with some of the Aboriginal Groups (with the Ontario Power Authority (OPA) and Hydro One in attendance) in January 2007 at which time OPA and Hydro One provided a Project briefing/overview. Additional meetings are planned for all of the identified Aboriginal Groups to continue with the engagement process.

ENVIRONMENTAL ASSESSMENT STATUS

1.0 BACKGROUND

The project is subject to an Individual Environmental Assessment (EA) under the Ontario *Environmental Assessment Act* (the *"Act"*).

In order to meet the urgent in-service timeline, concurrent EA and leave-to-construct OEB approval processes are being followed for the project. The schedule assumes that development and approval of the EA Terms of Reference (TOR) occurs from March to September, 2007, at the same time that the OEB section 92 process is proceeding. The S.92 application will be updated if material differences from the proposed project come to light through the EA process. A conditional leave-to-construct approval based on the future EA approval is assumed by October, 2007, at about the time that the approval of the EA Terms of Reference is received. To meet the target in-service date, EA approval is required by September 2008.

The OPA's Transmission Discussion Paper Number 5 released in November 2006 outlined the need and recommended further technical assessment of two options for a transmission line to deliver power from the Bruce area to the rest of the Province. One option was a transmission line from Bruce to Essa, within a widened existing transmission corridor. The other option was a transmission line from Bruce to Milton, also within a widened existing transmission corridor. Approximately 60% of the right-of-way is common for these two routes. The Discussion Paper can be found in Exhibit B, Tab 6, Schedule 5.

Subsequent to the release of OPA's Transmission Discussion Paper Number 5 and related OPA stakeholdering, the OPA sent two letters to Hydro One (December 22, 2006 and

March 23, 2007) that, among other things, advised Hydro One to initiate the work required to build a transmission line from Bruce to Milton to deliver power by December 2011. As stated in the March 23rd OPA letter to Hydro One, this is the only alternative that meets the overall need for the project. Copies of the two letters can be found in Exhibit B, Tab 6, Schedule 5, Appendices 2 and 4.

2.0 EA TERMS OF REFERENCE

The EA will rely upon the previous work of the OPA to address need and alternatives, consistent with statutory environmental assessment requirements. Through the TOR, Hydro One will seek a scoped EA as permitted under the focusing provisions of the Ministry of the Environment's Code of Practice, *"Preparing and Reviewing Terms of Reference for Environmental Assessments in Ontario (Draft October, 2006)"*. The scoping will be based on the OPA's assessment and determination, the conclusions of which are found in the March 23rd OPA letter (Exhibit B, Tab 6, Schedule 5, Appendix 4). As noted above, the Bruce to Milton route is the only alternative that meets the need and objectives.

Initial consultation on the TOR will be undertaken with provincial ministries and federal authorities. Hydro One will discuss the TOR with the public at the PICs and will make the TOR available on the project website. Notice that the TOR has been posted on the website will be provided to those expressing interest, and a copy will be mailed to those who request it. Upon submission of the TOR to the Ministry of Environment, the TOR will be made available to all interested parties on the Environmental Bill of Rights website. To meet the target in-service date, it is expected that the TOR will be submitted in June 2007 and approved by September of 2007.

3.0 ENVIRONMENTAL ASSESSMENT

Subject to the approved TOR and the requirements therein, Hydro One will conduct appropriate studies, consultation processes, Aboriginal engagement activities and prepare the EA. During the summer of 2007 and most of 2008 Hydro One will gather all available data, including field studies as required. Throughout the EA process, Hydro One will consult with various levels of government, Aboriginal groups, landowners, and other interested parties. Hydro One will apply appropriate mitigation for the identified environmental concerns and will fully document issues and Hydro One responses. An EA submission to the Ministry of Environment will be made thereafter.

To meet the target in-service date, EA approval is required by September 2008.

LAND MATTERS

1.0 LAND DESCRIPTION

1.1 Width(s) of any Right-of-Way (ROW) Required on New and/or Existing Easements

A new 500 kV transmission line from the Bruce Power Complex to Milton SS is proposed and, as a result, the existing transmission corridor from Bruce to Milton needs to be widened. Since the width of the existing corridor varies in size due to the existing 500 kV or 230 kV lines, the new width of the corridor will be determined as it relates to the adjacent existing rights and occupation, EA process and technical considerations.

The approximate widening required for the corridor is shown below, in addition to the widths of the existing corridor (approximate) for each major section of the existing high voltage line.

Table 1

Width and Length of Required Widening of Existing Transmission Corridor

Existing Lines	Existing ROW Width (ft)	Additional ROW Width (ft)	Length of Corridor (km)
Bruce A to Bruce Junction Area	580	Nil	3
Bruce B to Bruce Junction Area	580	Nil	3
500 kV line – Bruce Junction to WillowCreek Area	900	Nil	17
500 kV line – WillowCreek to Hanover Area	320	175	44
230 kV line – Hanover to Colbeck Area	320	195	45
500 kV line - Colbeck to Milton SS Area	250	175	67
TOTAL LENGTH			**179 km**

The widened corridor will traverse a majority of agricultural, open space and other properties. The topography of the corridor lands consists of rolling terrain with some river crossings and some aggregate operations. Certain sections of the corridor will cross lands within the Niagara Escarpment boundaries and designated greenbelt areas.

1.2 Location and Ownership of Land with Existing Easements and/or any New Easements or Land Use Rights that will be Required

The location of existing easement rights on properties along the Bruce to Milton route is shown on the maps at Exhibit B, Tab 6, Schedule 11. These maps also indicate the proposed abutting easement route and location across these individual properties. The land accommodating existing easements and the proposed widening is predominately owned in fee simple by private landowners. Other rights are secured by way of notice, licence, permit or statutory rights, as the existing lines and proposed widening cross municipal road allowances, various railway corridors, publicly-owned lands, parks or Conservation Authority property and Provincially-owned corridors, respectively.

1.3 Need and Amount of Additional Temporary Working Rights Required at Designated Locations such as Crossings or Rivers, Roads, Railways, Drains and other Facilities

Additional temporary working rights will be required, but they are not significant. Temporary property rights may be required when crossing or paralleling existing or planned utilities (e.g., pipelines, power lines) or other planned infrastructure (e.g., highways), and building construction access roads and working pads. These requirements will be determined and confirmed at the engineering design stage. Access agreements with landowners will be required.

2.0 LAND RIGHTS

2.1 Type of Land Rights Proposed to be Acquired for the Project and Related Facilities (e.g., permanent easement, fee simple)

The new land rights paralleling the existing corridor rights will be secured by way of registered easements, with some fee simple acquisitions as a result of buy-out of the total holding due to dwellings and/or major operational buildings being located on the widened corridor.

2.2 Nature and Relative Proportions of Land Ownership Along the Proposed Route (e.g., freehold, Crown or public lands)

There are over 400 different private, public and corporate parcels affected by the widening.

The widened route will cross approximately 92 municipal road allowances, not including some unopened road allowances. The provisions of the *Electricity Act, 1998*, as amended, permit the use of public roads and road allowances for electrical utility installations. Adequate notice and coordination of occupation needs and construction impacts will be communicated with the municipalities affected.

The rights for the 6 new railway crossing locations will be secured by way of licence from the particular railway company affected. Licences for the existing 500 kV and 230 kV transmission lines will be amended to include the new right-of-way requirements.

Permit rights and approvals will be secured to allow the construction of new transmission lines to cross rivers and riverbanks held in public trust by the Ministry of Natural

Resources. Permit rights and approvals will also be secured to cross waterways whose jurisdiction and control throughout the various municipalities is assigned to the Grand River Conservation Authority or Halton Region Conservation Authority.

2.3 Where no New Land Rights are Required, Provide a Description of the Existing Land Rights that Allow for the Project

Approximately 70 km of the existing corridor are owned by the Province of Ontario. The corridor width on Provincial ownership lands will accommodate the additional right-of-way needs for the new 500 kV transmission line in certain sections, e.g., immediately outside of the Bruce generating plant and just north of the Milton SS. Where additional rights are required (beyond the existing Provincially-owned corridor) on adjacent private lands, new easements will be secured. Legislation provides Hydro One with primary rights to expand its facilities on Provincially-owned corridors.

3.0 LAND ACQUISITION PROCESS

3.1 Identification of the Properties and the Property Owners and/or Tenants Affected by the Proposed Construction (landowners line list)

The properties that will be impacted by the new construction are shown on the maps referred to above and included in Exhibit B, Tab 6, Schedule 11.

Hydro One will carry out negotiations with affected landowners to secure settlements. In addition, Hydro One will be using the expropriation process to secure all property rights required by the project.

3.2 Extent of Notification to Landowners Regarding the Routing of the New Facility, the Environmental Assessment and the Facility Application

In addition to the standard notice received according to the OEB Letter of Direction for the project, landowners will receive notice of the route through various additional means, e.g., PICs to be conducted by Hydro One and advertisements in local newspapers.

3.3 Applicant's Plan for Acquiring New Easement or for Amending Existing Easements

Hydro One will be acquiring new rights, either by negotiated settlement with individual landowners and/or by expropriation as contemplated under the *OEB Act* and thereafter the *Expropriations Act*.

At the point of this section 92 filing, no direct consultation/negotiation with private landowners has occurred. Landowners will receive initial notification by means of notice of Hydro One's Leave to Construct application. Hydro One will initiate initial communication/discussions and consultation through PICs, after filing the section 92 application. Initial meetings with senior staff in affected municipalities have taken place on the proposed route and with Aboriginal group representatives.

Hydro One will also be applying for early access rights under section 98 of the *OEB Act* to conduct surveys and other pre-construction activities.

4.0 FORMS

Copies of the following documents are enclosed (refer to Exhibit B, Tab 6, Schedule 9):

- Easement Agreement (Appendix 1);
- Agreement of Purchase and Sale (Appendix 2);
- Offer to Grant an Easement (Appendix 3);
- Option to Purchase (Appendix 4);
- Damage Claim Form (Appendix 5);
- Damage Release Form (Appendix 6);
- Testing and Associated Access Routes (Appendix 7); and,
- Off-Corridor Temporary Access and Access Roads (Appendix 8).

LEGAL AGREEMENTS / FORMS

Appendix 1	Easement Agreement;
Appendix 2	Agreement of Purchase and Sale;
Appendix 3	Offer to Grant an Easement;
Appendix 4	Option to Purchase;
Appendix 5	Damage Claim Form;
Appendix 6	Damage Release Form;
Appendix 7	Testing and Associated Access Routes; and,
Appendix 8	Off-Corridor Temporary Access and Access Roads.

APPENDIX 1

Easement Agreement

EASEMENT AGREEMENT

Schedule "A"

The Transferor is the owner in fee simple and in possession of xxxxxxxxx

(the **"Lands"**)

Hydro One Networks Inc. (the "Transferee") has erected, or is about to erect, certain Works [as more particularly described in paragraph 1(a)] in, through, under, over, across, along and upon the Lands.

1. The Transferor hereby grants and conveys to the Transferee, its successors and assigns the rights and easement, free from all encumbrances and restrictions, the following unobstructed and exclusive rights, easements, rights-of-way, covenants, agreements and privileges in perpetuity (the **"Rights")** in, through, under, over across, along and upon that portion of the Lands of the Transferor described herein as xxxxxxxxxxxxx described as Part xxxxxx of Reference Plan xxxxxxxxxx hereto annexed (the **"Strip"**) for the following purposes:

    (a) To enter and lay down, install, construct, erect, maintain, open, inspect, add to, enlarge, alter, repair and keep in good condition, move, remove, replace, reinstall, reconstruct, relocate, supplement and operate and maintain at all times in, through, under, over, across, along and upon the Strip and electrical transmission system and telecommunications system consisting in both instances of pole structures, steel towers, anchors, guys and braces and all such aboveground or underground lines, wires, cables, telecommunications cables, grounding electrodes, conductors, apparatus, works, accessories, associated material and equipment, and appurtenances pertaining to or required by either such system (all or any of which are herein individually or collectively called the **("Works")** as in the opinion of the Transferee are necessary or convenient thereto for use as required by Transferee in its undertaking from time to time, or a related business venture.

    (b) To enter on and selectively cut or prune, and to clear and keep clear, and remove all trees (subject to compensation to owners for merchantable wood values), branches, bush and shrubs and other obstructions and materials, over or upon the Strip, and without limitation, to cut and remove all leaning or decayed trees located on the Lands whose proximity to the Works renders them liable to fall and come in contact with the Works or which may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(c) To conduct all engineering, legal surveys, and make soil tests, soil compaction and environmental studies and audits in, under, on and over the Strip as the Transferee in its discretion considers requisite.

(d) To erect, install, construct, maintain, repair and keep in good condition, move, remove, replace and use bridges and such gates in all fences which are now or may hereafter be on the Strip as the Transferee may from time to time consider necessary.

(e) Except for fences and permitted paragraph 2(a) installations, to clear the Strip and keep it clear of all buildings, structures, erections, installations, or other obstructions of any nature (hereinafter collectively called the **"obstruction"**) whether above or below ground, including removal of any materials and equipment or plants and natural growth, which in the opinion of the Transferee, endanger its Works or any person or property or which may be likely to become a hazard to any Works of the Transferee or to any person or property or which do or may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(f) To enter on and exit by the Transferor's access routes and to pass and repass at all times in, over, along, upon and across the Strip and so much of the Lands as is reasonably required, for Transferee, its respective officers, employees, agents, servants, contractors, subcontractors, workmen and permitees with or without all plant machinery, material, supplies, vehicles and equipment for all purposes necessary or convenient to the exercise and enjoyment of this easement subject to compensation afterwards for any crop or other physical damage only to the Lands or permitted structures sustained by the Transferor caused by the exercise of this right of entry and passageway.

(g) To remove, relocate and reconstruct the line on or under the Strip subject to payment by the Transferee of additional compensation for any damage caused thereby.

2. The Transferor agrees that:

(a) It will not interfere with any Works established on or in the Strip and shall not, without the Transferee's consent in writing, erect or cause to be erected or permit in, under or upon the Strip any obstruction or plant or permit any trees, bush, shrubs, plants or natural growth which does or may interfere with the Rights granted herein. The Transferor agrees it shall not, without the Transferee's consent in writing, change or permit the existing configuration, grade or elevation of the Strip to be changed, and the Transferor further agrees that no excavation or opening or work which may disturb or interfere with the existing surface of the Strip shall be done or made unless consent therefor in writing has been obtained from Transferee, provided however, that the Transferor shall not be required to obtain such permission in case of emergency. Notwithstanding the foregoing, in cases where in the reasonable discretion of the Transferee, there is no danger or likelihood of danger to the Works of the Transferee or to any persons or property and the safe or serviceable operation of this easement by the Transferee is not interfered with, the Transferor may at its expense and with the prior written approval of the Transferee, construct and maintain roads, lanes walks, drains, sewers water pipes, oil and gas pipelines, fences (not to exceed 2 metres in height) and service cables on or under the Strip (the **"Installation"**) or any portion thereof; provided that prior to commencing such Installation, the Transferor shall give to the Transferee thirty (30) days' notice in writing thereof to enable the Transferee to have a representative present to inspect the proposed Installation during the performance of such work, and provided further that Transferor comply with all instructions given by such representative and that all such work shall be done to the reasonable satisfaction of such representative. In the event of any unauthorized interference aforesaid or contravention of this paragraph, or if any authorized interference, obstruction or Installation is not maintained in accordance with the Transferee's instructions or in the Transferee's reasonable opinion, may subsequently interfere with the Rights granted herein, the Transferee may at the Transferor's expense, forthwith remove, relocate, clear or correct the offending interference, obstruction, Installation or contravention complained of from the Strip, without being liable for any damages cause thereby.

(b) Notwithstanding any rule of law or equity, the Works installed by the Transferee shall at all times remain the property of the Transferee, notwithstanding that such Works are or may become annexed or affixed to the Strip, and shall at anytime and from time to time be removable in whole or in part by Transferee.

(c) No other easement or permission will be transferred or granted and no encumbrances will be created over or in respect to the Strip, prior to the registration of a Transfer of this grant of Rights.

(d) The Transferor will execute such further assurances of the Rights in respect of this grant of easement as may be requisite.

(e) The Rights hereby granted:

(i) shall be of the same force and effect to all intents and purposes as a covenant running with the Strip; and

(ii) are declared hereby to be appurtenant to and for the benefit of the Works and undertaking of the Transferee described in paragraph 1(a).

3. The Transferee covenants and agrees to obtain at its sole cost and expense all necessary postponements and subordinations (in registrable form) from all current and future prior encumbrancers, postponing their respective rights, title and interest to the transfer of easement herein so as to place such Rights and easement in first priority on title to the Lands.

4. There are no representations, covenants agreements, warranties and conditions in any way relating to the subject matter of this grant of Rights whether expressed or implied, collateral or otherwise except those set forth herein.

5. No waiver of a breach or any of the covenants of this grant of Rights shall be construed to be a waiver of any succeeding breach of the same or any other covenant.

6. The burden and benefit of this transfer of Rights shall run with the Strip, and the Works and undertaking of the Transferee and shall extend to, be binding upon and enure to the benefit of the parties hereto and their respective heirs, executors, administrators, successors and assigns.

APPENDIX 2

Agreement of Purchase and Sale.

AGREEMENT OF PURCHASE AND SALE

THIS AGREEMENT made and entered into as of this th day of , 2007,

BETWEEN:

(collectively the **"Vendor"**)

OF THE FIRST PART

AND:

HYDRO ONE NETWORKS INC.

(the **"Purchaser"**)

OF THE SECOND PART

WITNESSETH THAT in consideration of the mutual covenants, agreements and payments herein provided, the parties hereto covenant and agree as follows:

1.0 OFFER

1.1 The Purchaser hereby offers to buy from the Vendor certain lands and premises of the Vendor, more particularly described as ●, (the **"Property"**) and more particularly described in Schedule “A” attached hereto, upon and subject to the terms and conditions hereinafter set forth.

1.2 The Purchaser acknowledges having inspected the Property prior to submitting this Offer and understands that upon acceptance of this Offer by the Vendor there shall be a binding agreement of Purchase and Sale between the Purchaser and the Vendor.

1.3 Included in the Purchase Price is the purchase of all of the Vendor's interest in all fixtures, improvements, and appurtenances located on the Property except those listed below which are expressly excluded: nil

2.0 PURCHASE PRICE

2.1 The purchase price to be paid by the Purchaser to the Vendor for the Property shall be the sum of **● THOUSAND ($●,000.00) Canadian Dollars,** (the **"Purchase Price"**) payable as follows:

(a) ● ($●.00) dollars submitted by the Purchaser upon the execution of this Agreement as a deposit to be held in trust pending completion or other termination of this Agreement and to be credited on account of the Purchase Price on completion (the **"Deposit”**)

(b) the balance of the Purchase Price by cash, bank draft or uncertified cheque at the time of closing in accordance with section 3.2 (b) of this Agreement.

3.0 CLOSING

3.1 The closing of this transaction shall take place at ____:____ am/pm on the ● th day of ●, 200● or such earlier time and at such place as shall be agreed in writing by the parties hereto (the **"Closing"**).

3.2 On Closing,

(a) Vacant possession of the Property shall be given to the Purchaser.

(b) Purchaser shall pay the balance of the Purchase Price to the Vendor in accordance with section 2.1(b) of this Agreement;

(c) Rents, realty taxes, local improvement charges, water and unmetered utility charges and the cost of fuel as applicable shall be apportioned and allowed to the date of completion (the day itself to be apportioned to the Purchaser).

(d) In addition to the Purchase Price, the Purchaser shall pay and the Vendor will collect Goods and Services Tax (**"GST"**) on Closing in the amount of 7% of the Purchase Price (or the amount then applicable) together with the balance of the Purchase Price on Closing, unless the Purchaser provides at the time of Closing a satisfactory declaration and indemnity in favour of the Vendor stating that the Purchaser is a registrant for the purposes of GST under the *Excise Tax Act*, R.S.C. 1985, c. E-15, as amended, and covenants with the Vendor to pay all GST payable in connection with this transaction directly to Revenue Canada, indicating the Purchaser's registration number, that such registration is in good standing, that the Purchaser is acquiring the Property as principal, and that the Purchaser agrees to indemnify and save harmless the Vendor against all loss or costs incurred as a result of any claim, suit or liability whatever with respect to the payment of any GST arising out of the sale of the Property, including any penalties, interest or other charges.

4.0 REPRESENTATIONS AND WARRANTIES OF VENDOR

4.1 The Purchaser shall be allowed thirty (30) days from the date of this Agreement (the **"Inspection Period"**) to satisfy itself with respect to all matters respecting the Property including its present state of repair and condition and any structures thereon, all encumbrances and all regulations and by-laws governing the Property and the Vendor grants to the Purchaser the right to enter upon the Property and to conduct such inspections, surveys and tests as the Purchaser, acting reasonably, deems necessary in this regard, provided the Purchaser takes all reasonable care in the conduct of such inspections, surveys and tests and restores the Property to its prior condition so far as reasonably possible following such inspections and tests. The Vendor assumes no responsibility for and the Purchaser shall indemnify and save harmless the Vendor from and against all claims, demands, costs, damages, expenses and liabilities whatsoever arising out of its presence on the Property or of its activities on or in connection with the Property during the Inspection Period.

4.2 If for any reason, the Purchaser, acting reasonably, is not satisfied with respect to such matters arising from its activities in Section 4.1, it may deliver a notice (the **"Notice of Termination"**) to the Vendor prior to the expiry of the Inspection Period indicating that it is not satisfied with respect to such matters and desires to terminate this Agreement and release the Vendor from any further obligations. Upon delivery by the Purchaser of a Notice of Termination to the Vendor, and this Agreement shall be at an end and the Vendor shall return the deposit to the Purchaser without interest or deduction and neither Party shall have any further obligation to the other respecting the Agreement.

5.0 TITLE SEARCH PERIOD

5.1 The Purchaser shall be allowed thirty (30) days from the date of this Agreement to investigate title to the Property at its own expense (the **"Title Search Period"**), to satisfy itself that there are no outstanding encumbrances, or liens save and except those listed in Schedule “B” attached hereto and until the earlier of: (i) thirty (30) days from the later of the last date of the title search period or the date or which the conditions in this Agreement are fulfilled or otherwise waived or; (ii) five (5) days prior to completion, to satisfy itself that there are no outstanding work orders or deficiency notices affecting the property. Vendor hereby consents to the Municipality or other governmental agencies releasing to the Purchaser details of all outstanding work orders affecting the Property and the Vendor agrees to execute and deliver such further authorizations in this regard as Purchaser may reasonably require.

5.2 Provided that the title to the Property is good and free from all registered restrictions, charges, liens and encumbrances except those listed in Schedule “B” attached hereto, if within the Title Search Period, any valid objection to title is made by the Purchaser in writing to the Vendor together with documentary verification thereof, and which the Vendor shall be unwilling or unable to remove and which the Purchaser will not waive, this Agreement, notwithstanding any intermediate acts or negotiations in respect of such objections, shall be at an end and the Deposit shall be returned to the Purchaser, without interest or deduction, and the Vendor shall not be liable for any costs or damages and the Vendor and the Purchaser shall be released from all obligations hereunder, and the Vendor shall also be released from all obligations under this Agreement, save and except those covenants of the Purchaser expressly stated to survive Closing or other termination of this Agreement. Save as to any valid objection to title made in accordance with this Agreement and within the Title Search Period, and except for any objection going to the root of title, Purchaser shall be conclusively deemed to have accepted Vendor's title to the Property.

5.3 The Vendor and Purchaser agree that there is no condition, express, or implied, representation or warranty of any kind that the future intended use of the Property by the Purchaser is or will be lawful except as may be specifically stipulated elsewhere in this Agreement.

5.4 The Vendor agrees to provide to the Purchaser any existing survey of the property, within Fifteen (15) days from the date of the Agreement herein.

6.0 REPRESENTATIONS AND WARRANTIES OF PURCHASER

6.1 Purchaser shall, at its own cost, forthwith make such investigation as the Purchaser deems appropriate of the Property and Vendor's title as provided for in this Agreement and shall notify the Vendor of any objection to title, together with a complete copy of any documents and other material information related thereto prior to the expiry of the Inspection Period and Title Search Period.

7.0 INSURANCE

7.1 The Vendor covenants and agrees that the Property and all structures or fixtures being purchased are insured, and that such insurance will remain in force until closing. The Property and all structures or fixtures being purchased shall be and remain at the risk of the Vendor until Closing.

7.2 Pending completion, Vendor shall hold all insurance policies and the proceeds thereof in trust for the parties as their interests may appear and in the event of substantial damage to the Property the Purchaser may either terminate this Agreement and have all monies paid by the Purchaser returned to the Purchaser without interest or deduction or else take the proceeds of any insurance and complete the purchase.

8.0 RESTRICTIONS AND LIMITATIONS

8.1 This Agreement shall be effective to create an interest in the Property only if the applicable subdivision control provisions of the *Planning Act*, R.S.O. 1990, as amended, are complied with by the Vendor prior to Closing. The Vendor shall forthwith make any application to the local Committee of Adjustment or Land Division Committee for any consent that may be required pursuant to the Planning Act. In the event that any such application for consent is denied, or any condition imposed by such body is unacceptable to the Vendor, this Agreement shall be terminated and the Deposit returned to the Purchaser without interest or deduction.

9.0 ADDITIONAL PROVISIONS

9.1 The Transfer/Deed of Land (the **"Transfer"**), save for Land Transfer Tax Affidavits, shall be prepared in registrable form by the Vendor, and the Purchaser covenants at its cost to register the Transfer on Closing. If requested by Purchaser, Vendor covenants that the Transfer Deed to be delivered on completion shall contain the statements contemplated by s. 50(22) of the *Planning Act*, R.S.O. 1990.

9.2 Time shall in all respects be of the essence hereof provided that the time for doing or completing of any matter provided for herein may be extended or abridged by an agreement in writing signed by the Parties or by their respective solicitors who are specifically authorized in that regard.

9.3 Any tender of documents or money hereunder may be made upon the Parties or their respective solicitors on the Closing day. Money may be tendered by bank draft or uncertified cheque.

9.4 The Vendor shall be responsible for and agrees to pay any applicable commission, negotiated and payable in accordance with a listing agreement with the Vendor's agent, upon successful Closing of the transaction contemplated by this Agreement, which commission shall be paid out of the proceeds of the Purchase Price.

9.5 Where this Agreement requires notice to be delivered by one party to the other, such notice shall be given in writing and delivered either personally, or by pre-paid registered post or by facsimile, by the party wishing to give such notice, or by the solicitor acting for such party, to the other party or to the solicitor acting for the other party at the addresses noted below:

To: Vendor

Facsimile No:
Phone:

Attention:

To: Purchaser

Hydro One Networks Inc.
Real Estate Services
P.O. Box 4300
Markham, ON
L3R 5Z5

Facsimile No:
Phone:

Attention:

Such notice shall be deemed to have been given, in the case of personal delivery, on the date of delivery, and, where given by registered post, on the third business day following the posting thereof, and if sent by facsimile, the date of delivery shall be deemed to be the date of transmission if transmission occurs prior to 4:00 p.m. (Toronto time) on a business day and on the business day next following the date of transmission in any other case. It is understood that in the event of a threatened or actual postal disruption in the postal service in the postal area through which such notice must be sent, notice must be given personally as aforesaid or by facsimile, in which case notice shall be deemed to have been given as set out above.

9.6 The Parties acknowledge that there are no covenants, representations, warranties, agreements or conditions, express or implied, collateral or otherwise, forming part of or in any way affecting or relating to this Agreement save as expressly set out in this Agreement and that this Agreement and all Schedules hereto constitute the entire agreement between the parties and may not be modified except as expressly agreed between the Vendor and Purchaser in writing.

9.7 Should any provision or provisions of this agreement be declared illegal or unenforceable, it or they shall be considered separate and severable from the Agreement and its remaining provisions shall remain in force and be binding upon the parties hereto as though the said provision or provisions had never been included.

9.8 No act or omission or delay in exercising any right or enforcing any term, covenant or agreement to be performed under this Agreement shall impair such right or be construed as to be a waiver of any default or acquiescence in such failure to perform, unless such waiver shall be given or acknowledged in writing.

9.9 This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario.

9.10 This Agreement shall constitute the entire Agreement between the Purchaser and Vendor and there is no representation, warranty, collateral agreement or condition affecting this Agreement or the Property or supported hereby other than as expressed herein in writing. This Agreement shall be read with all changes of gender or number required by the context.

9.11 This Agreement and everything herein contained shall operate to the benefit of, and be binding upon, the respective heirs, successors, permitted assigns and other legal representatives, as the case may be, of each of the Parties hereto.

9.12 Each of the Vendors warrants that spousal consent is not necessary to this transaction under the provision of the Family Law Act, R.S.O. 1990 unless each of the Vendors' spouse has executed the consent hereinafter provided.

9.13 Where each of the Vendor and the Purchaser retain a solicitor to complete this Agreement and where the transaction contemplated herein will be completed by electronic registration pursuant to Part 111 of the Land Registration Reform Act, R.S.O. 1990, and any amendments thereto, the Vendor and the Purchaser acknowledge and agree that the delivery of documents and the release thereof to the Vendor and the Purchaser may, at the solicitor's discretion; (a) not occur contemporaneously with the registration of the Transfer/Deed of Land (and other registrable) documentation), and (b) be subject to conditions whereby the solicitor receiving documents and/or money will be required to hold them in trust and not release them except in accordance with the terms of a written agreement between the solicitors.

9.14 Except as otherwise provided herein, each Party shall be responsible to pay its own taxes, legal costs, and the cost of preparation and registration of its own documents.

9.15 This Agreement and any right or interest transferred hereby may be registered on title to the Property.

9.16 The provisions of the attached Schedules "A" and "B" shall form part of this Agreement as if set out herein.

9.17 The Vendor and Purchaser agree to take all necessary precautions to maintain the confidentiality of the terms and conditions contained herein. The Vendor acknowledges that this Agreement and any information or documents that are provided to the Purchaser may be released pursuant to the provisions of the *Freedom of Information and Protection of Privacy Act,* R.S.O. 1990, c. F.31, as amended. This acknowledgment shall not be construed as a waiver of any right to object to the release of this Agreement or of any information or documents.

IN WITNESS WHEREOF the Parties have hereunto set their respective hands and seals to this Agreement of Purchase and Sale.

SIGNED, SEALED AND DELIVERED In the presence of	)	
	)	______________________________
(seal)	)	Vendor
	)	
	)	
	)	
SIGNED, SEALED AND DELIVERED	)	Consent Signature & Release of
In the presence of	)	Vendor's Spouse, if non-owner.
	)	
	)	______________________________
(seal)		

HYDRO ONE NETWORKS INC.

Per: ______________________________

Title: ______________________________

I have authority to bind the Corporation

APPENDIX 3

Offer to Grant an Easement.

OFFER TO GRANT AN EASEMENT TO HYDRO ONE NETWORKS INC.

I/We, [Insert Transferor's Name(s)] **(**the **"Transferor(s)"**), being the owner/owners of [Insert Complete Legal Description] (herein called the "**Lands**") in consideration of payment of the sum of five **($5.00) DOLLARS** (the **"Offer Consideration")**, and other good and valuable consideration (the sufficiency of which consideration is hereby acknowledged), hereby covenants and agrees as follows:

1(a) THE Transferor hereby grants to Hydro One Networks Inc. its successors and assigns (the **"Transferee"**) the exclusive right, irrevocable during the periods of time below specified in paragraph 2, (the **"Offer"**) to purchase free from all encumbrances upon the terms and conditions hereinafter set out the perpetual rights, easements and privileges set out in the Transfer and Grant of Easement document (the **"Transfer of Easement"**) annexed hereto as Schedule "A" (the **"Rights"**) in, through, under, over, across, along and upon that portion of the above Lands as shown highlighted in red on Schedule "B" hereto annexed (the **"Strip"**).

1(b) THE purchase price for the Rights shall be the sum of [Insert amount] **($ 00.00)** (Dollars) (the "**Purchase Price**") of lawful money of Canada to be paid by cash or uncertified cheque to the Transferor on Closing.

2. THIS Offer may be accepted by Transferee any time within 60 days from the date of this Agreement by a letter delivered or facsimile transmission or mailed postage prepaid and registered, to the Transferor at the address set out in paragraph 12. If this Offer is not accepted within this time frame, this Agreement and everything herein contained shall be null, void and of no further force and effect. If this offer is accepted by the Transferee in the manner aforesaid, this Agreement and the letter accepting such Offer shall then become a binding contract between the parties, and the same shall be completed upon the terms herein provided for.

3. THE Transfer of Easement arising from the acceptance of this Offer shall be executed and delivered to the Transferee on or before the One Hundred and Twentieth (120^{th}) day after the date of Transferee's acceptance of this Offer (the **"Closing"**) subject to the availability of a satisfactory survey, if required, and time shall in all respects be of the essence hereof. If no satisfactory survey is then available, the date for Closing shall be extended in Transferee's sole discretion to a date not exceeding sixty (60) days from the said One Hundred and Twentieth (120^{th}) day and this purchase transaction shall then be completed on such extended date for Closing.

4. IF the Transferee accepts the Offer herein: a) the Transferee shall not grant or transfer an easement or permission, or create any encumbrance over or in respect of the Strip prior to registration of the Transfer of Easement, and b) the Transferee has permission to approach prior encumbrancers to obtain all necessary consents, postponements or subordinations (in registrable form) from all current and future prior encumbrancers, consenting to this Transfer of Easement, and/or postponing their respective rights, title and interest so as to place such Rights and Transfer of Easement in first priority on title to the Strip.

5. TITLE to the Strip shall at Closing be good and free from all registered restrictions, charges, liens, easements and encumbrances of any kind whatsoever except for those title matters disclosed in Schedule "C".

6. THE Transfer of Easement and all ancillary documents necessary to register same on title shall be prepared by and at the expense of the Transferee and shall be substantially in the form as the annexed Schedule "A". The Transferor hereby covenants and agrees that the Transferee may, at its option, register this Agreement or Notice thereof, and the Transfer of Easement on title to the Lands, and the Transferor hereby covenants and agrees to execute, at no further cost or condition to the Transferee, such other instruments, plans and documents as may reasonably be required by the Transferee to effect registration of this Agreement or Notice thereof prior to Closing and the Transfer of Easement at any time thereafter.

7. THE Transferor covenants and agrees with Transferee that it has the right to convey the Rights without restriction and that Transferee will quietly possess and enjoy the Rights and that Transferor will execute upon request such further assurances of the Rights as may be requisite to give effect to the provisions of this Agreement.

8. AS of the date of the Transferee's acceptance of the Offer, the Transferor grants to the Transferee, in consideration of the Offer Consideration, free from all encumbrances and restrictions the following rights, easements, rights of way, covenants, agreements and privileges in, through, under, over, across, along and upon the Strip:

(a) to erect, maintain, operate, repair, replace, relocate, upgrade, reconstruct, and remove at any time and from time to time, an electrical transmission line or lines and communication line or lines consisting of all necessary pole structures and steel towers, poles and anchors with all guys, braces, wires, cables and associated material and equipment (all or any of which works are herein called "the line");

(b) to erect, maintain and use such gates in all fences which are now or may hereafter be on the Strip as the Transferee may from time to time consider necessary;

(c) to mark the location of the line under the Strip by suitable markers, but said markers when set in the ground shall be placed in fences or other locations which will not interfere with any reasonable use the Transferor shall make of the Strip;

(d)

(i) to cut selectively trees and shrubs on the Strip and to keep it clear of all trees, shrubs and brush which may interfere with the safe operation and maintenance of the line;

(ii) subject to payment of additional compensation therefore, to cut prune, and remove if necessary trees located outside the Strip whose condition renders them liable to interfere with the safe operation and maintenance of the line;

(e) To conduct engineering and legal surveys in, on and over the Strip;

(f) To clear the Strip and keep it clear of all buildings, structures and other obstructions of any nature whatever including removal of any materials which in the opinion of the Transferee are hazardous to the line. Notwithstanding the foregoing, in all cases where in the sole discretion of the Transferee the safe operation and maintenance of the line is not endangered or interfered with, the Transferor from time to time or the person or persons entitled thereto, may with prior written approval of Transferee, at his or her own expense construct and maintain roads, lanes, walks, drains, sewers, water pipes, oil and gas pipelines, and fences (not to exceed 2 metres in height) on or under the Strip or any portion thereof, provided that prior to commencing any such installation, the Transferor shall give the Transferee 30 days notice in writing so as to enable Transferee to have a representative inspect the site and be present during the performance of the work and that the Transferor complies with any instructions which may be given by such representative in order that such work may be carried out in such a manner as not to endanger, damage or interfere with the line.

(g) To enter on, and exit from, and to pass and repass at any and all times in, over, along, upon, across, through and under the Strip and so much of the Lands as may be reasonably necessary, at all reasonable times, for the Transferee and its respective officers, employees, workers, permittees, servants, agents, contractors and subcontractors, with or without vehicles, supplies, machinery, plant, material and equipment for all purposes necessary or convenient to the exercise and enjoyment of the said rights and easement subject to payment by the Transferee of compensation for any crop or other physical damage only to the Land caused by the exercise of this right of entry and passageway; and

(h) To remove, relocate and reconstruct the line on or under the Strip, subject to payment by the Transferee of additional compensation for any damage caused thereby.

9. THE Transferor consents to the Transferee, its respective officers, employees, agents, contractors, sub-contractors, workers and permittees or any of them entering on, exiting and passing and repassing in, on, over, along, upon, across, through and under the Strip and so much of the Lands as may be reasonably necessary, at all reasonable times after the date of this Agreement until such time as this Offer is accepted and the purchase is completed with or without all plant, machinery, material, supplies, vehicles, and equipment, for all purposes necessary or convenient to the exercise and enjoyment of the Rights, subject to compensation afterwards for any crop or other physical damage only to the Lands or permitted structures sustained by the Transferor caused by the exercise of this right of entry and passageway.

10. THIS Agreement and Transfer and Grant of Easement Rights shall both be subject to the condition that the provisions of The Planning Act, R.S.O. 1990, c. P. 18, as amended, have, in the opinion of Transferee, been satisfactorily complied with. If after consultation with Provincial Agencies and Municipalities, the Transferee decides that the provisions of the Planning Act, R.S.O. 1990, c.P.18, and amendments thereto, have not been or cannot be complied with, it may, at its option, cancel this Agreement.

11. ANY documents or money payable hereunder may be tendered upon the parties hereto or their respective solicitors and money may be tendered by negotiable uncertified cheque or cash.

12. ANY acceptance of this Offer, demand, notice or other communication to be given in connection with this Agreement shall be given in writing and shall be given by personal delivery, by registered mail postage prepaid, or by facsimile transmission, addressed to the recipient as follows:

To: Transferee	To: Transferor
Hydro One Networks Inc. 185 Clegg Road, Markham, Ontario L6G 1B7	
Facsimile No:	Facsimile No.
Phone:	Phone:
Attention:	Attention:

or to such other address, facsimile number or individual as may be designated by notice given by either party to the other. Any acceptance of this offer, demand, notice or other communication shall be conclusively deemed to have been given when actually received by the addressee or upon the second day after the day of mailing.

13. THE Transferor represents that he is not now and at the time of Closing shall not be a spouse within the meaning of the Family Law Act, R.S.O. 1990, c. F. 3, as amended, failing which, the Transferor shall cause this Agreement and all related documents to be accepted and consented to in writing by the spouse of the Transferor to the satisfaction of the Transferee and at no further cost or condition.

14. IN the event of and upon acceptance of this Offer by the Transferee in manner aforesaid this Agreement and the letter accepting such Offer shall then become a binding contract of sale and purchase between the parties, and the same shall be completed upon the terms herein provided for.

15. The Transferee will covenant and agree with the Transferor to indemnify and save harmless the Transferor, his tenants, or other lawful occupiers of the Strip for any loss, damage and injury caused by the acceptance of the Offer and the granting and transfer of Rights or anything done pursuant thereto or arising from any accident (not excluding any Act of God) that would not have happened but for the presence of its line on the Strip, provided, however, that the Transferee shall not be liable to the extent to which such loss, damage, or injury is caused or contributed to by the neglect or default of the Transferor, his tenants guests, invitees or other lawful occupiers of the Strip or their servants, agents, or workmen.

16. THE Transferor covenants and agrees that if and before the Transferor sells, transfers, assigns, disposes (or otherwise parts with possession) of all or part of the Lands to a third party (the "Third Party") the Transferor shall use best efforts to ensure that the third party assumes the burden and benefit of this Agreement, and agrees to be bound by it. Accordingly the Transferor covenants and agrees to use best efforts to obtain from the Third Party a written acknowledgement and agreement that the Third Party is aware of this Agreement and will continue to be bound by the terms, conditions and stipulations of this Agreement.

17. ALL covenants herein contained shall be construed to be several as well as joint, and wherever the singular and the masculine are used in this Agreement, the same shall be construed as meaning the plural or the feminine or neuter, where the context or the identity of the Transferor/Transferee so requires.

18. THE burden and benefit of this Agreement shall run with the Strip and the works and undertaking of the Transferee and shall be binding upon and enure to the benefit of the parties hereto and their respective heirs, executors, administrators, successors and assigns.

IN WITNESS WHEREOF the Transferor has hereunto set their hands and seals to this Agreement, this _________ day of ______________________________, 2006

SIGNED
In the presence of)
) ________________________________
) Transferor's Name
)
)
)
) ________________________________
) Transferor's Name
)
)

SIGNED, Consent Signature & Release of
In the presence of) Transferor's Spouse, if non-owner.
)
)
)
) ________________________________

SCHEDULE "A"

(7) INTEREST / ESTATE TRANSFERRED

The Transferor is the owner in fee simple and in possession of **________________**(**"Lands"**).

The Transferee has erected, or is about to erect, certain Works (as more particularly described in paragraph 1(a) hereof) in, through, under, over, across, along and upon the Lands.

1 The Transferor hereby grants and conveys to Hydro One Networks Inc, its successors and assigns the rights and easement, free from all encumbrances and restrictions, the following unobstructed and exclusive rights, easements, covenants, agreements and privileges in perpetuity (the **"Rights"**) in, through, under, over, across, along and upon that portion of the Lands of the Transferor described herein and shown highlighted on Schedule "B" hereto annexed (the **"Strip"**) for the following purposes:

(a) To enter and lay down, install, construct, erect, maintain, open, inspect, add to, enlarge, alter, repair and keep in good condition, move, remove, replace, reinstall, reconstruct, relocate, supplement and operate and maintain at all times in, through, under, over, across, along and upon the Strip an electrical transmission system and telecommunications system consisting in both instances of a pole structures, steel towers, anchors, guys and braces and all such aboveground or underground lines, wires, cables, telecommunications cables, grounding electrodes, conductors, apparatus, works, accessories, associated material and equipment, and appurtenances pertaining to or required by either such system (all or any of which are herein individually or collectively called the **"Works"**) as in the opinion of the Transferee are necessary or convenient thereto for use as required by Transferee in its undertaking from time to time, or a related business venture.

(b) To enter on and selectively cut or prune, and to clear and keep clear, and remove all trees (subject to compensation for merchantable wood values), branches, bush and shrubs and other obstructions and materials in, over or upon the Strip, and without limitation, to cut and remove all leaning or decayed trees located on the Lands whose proximity to the Works renders them liable to fall and come in contact with the Works or which may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(c) To conduct all engineering, legal surveys, and make soil tests, soil compaction and environmental studies and audits in, under, on and over the Strip as the Transferee in its discretion considers requisite.

(d) To erect, install, construct, maintain, repair and keep in good condition, move, remove, replace and use bridges and such gates in all fences which are now or may hereafter be on the Strip as the Transferee may from time to time consider necessary.

(e) Except for fences and permitted paragraph 2(a) installations, to clear the Strip and keep it clear of all buildings, structures, erections, installations, or other obstructions of any nature (hereinafter collectively called the **"obstruction"**) whether above or below ground, including removal of any materials and equipment or plants and natural growth, which in the opinion of the Transferee, endanger its Works or any person or property or which may be likely to become a hazard to any Works of the Transferee or to any persons or property or which do or may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(f) To enter on and exit by the Transferor's access routes and to pass and repass at all times in, over, along, upon and across the Strip and so much of the Lands as is reasonably required, for Transferee, its employees, agents, contractors, subcontractors, workmen and permittees with or without all plant machinery, material, supplies, vehicles and equipment for all purposes necessary or convenient to the exercise and enjoyment of this easement, subject to compensation afterwards for any crop or other physical damage only to the Lands or permitted structures sustained by the Transferor caused by the exercise of this right of entry and passageway.

2. The Transferor agrees that:

(a) It will not interfere with any Works established on or in the Strip and shall not, without the Transferee's consent in writing, erect or cause to be erected or permit in, under or upon the Strip any obstruction or plant or permit any trees, bush, shrubs, plants or natural growth which does or may interfere with the Rights granted herein. The Transferor agrees it shall not, without the Transferee's consent in writing, change or permit the existing configuration, grade or elevation of the Strip to be changed and the Transferor further agrees that no excavation or opening or work which may disturb or interfere with the existing surface of the Strip shall be done or made unless consent therefore in writing has been obtained from Transferee, provided however, that the Transferor shall not be required to obtain such permission in case of emergency. Notwithstanding the foregoing, in cases where in the reasonable discretion of the Transferee, there is no danger or likelihood of danger to Works of the Transferee or to any persons or property and the safe or serviceable operation of this easement by the Transferee is not interfered with, the Transferor may at its expense and with the prior written approval of the Transferee, construct and maintain roads, lanes, walks, drains, sewers, water pipes, oil and gas pipelines and service cables on or under the Strip (the **"Installation"**) or any portion thereof; provided that prior to commencing such Installation, the Transferor shall give to the Transferee a minimum of ten days notice in writing thereof to enable the Transferee to have a representative present to inspect the proposed Installation during the performance of such work, and provided further that Transferor comply with all instructions given by such representative and that all such work shall be done to the reasonable satisfaction of such representative. In the event of any unauthorised interference aforesaid or contravention of this paragraph, or if any authorised interference, obstruction or Installation is not maintained in accordance with the Transferee's instructions or in the Transferee's reasonable opinion, may subsequently interfere with the Rights granted herein, the Transferee may at the Transferor's expense, forthwith remove, relocate, clear or correct the offending interference, obstruction, Installation or contravention complained of from the Strip, without being liable for any damages caused thereby.

(b) notwithstanding any rule of law or equity, the Works installed by the Transferee shall at all times remain the property of the Transferee, notwithstanding that such Works are or may become annexed or affixed to the Strip and shall at anytime and from time to time be removable in whole or in part by Transferee.

(c) No other easement or permission will be transferred or granted and no encumbrances will be created over or in respect to the Strip, prior to the registration of a Transfer of this grant of Rights.

(d) the Transferor will execute such further assurances of the Rights in respect of this grant of easement as may be requisite.

(e) the Rights hereby granted:

(i) shall be of the same force and effect to all intents and purposes as a covenant running with the Strip.

(ii) is declared hereby to be appurtenant to and for the benefit of the Works and undertaking of the Transferee described in paragraph 1(a).

3. The Transferee covenants and agrees to obtain at its sole cost and expense all necessary postponements and subordinations (in registrable form) from all current and future prior encumbrancers, postponing their respective rights, title and interests to the Transfer of Easement herein so as to place such Rights and easement in first priority on title to the Lands.

4. There are no representations, covenants, agreements, warranties and conditions in any way relating to the subject matter of this grant of Rights whether expressed or implied collateral or otherwise except those set forth herein.

5. No waiver of a breach or any of the covenants of this grant of Rights shall be construed to be a waiver of any succeeding breach of the same or any other covenant.

6. The burden and benefit of this transfer of Rights shall run with the Strip and the Works and undertaking of the Transferee and shall extend to, be binding upon and enure to the benefit of the parties hereto and their respective heirs, executors, administrators, successors and assigns.

CHARGEES

THE CHARGEE of land described in a Charge/Mortgage of Land dated ______________________

Between ______________________________ and ____

and registered as Instrument Number _____________ on _____________________________ does

hereby consent to this Easement and releases and discharges the rights and easement herein from the said

Charge/Mortgage of Land.

Name	Signature(s)	Date of Signatures Y M D
	Per:	
	______________________________________	
	______________________________________	

I/We have authority to bind the Corporation

Schedule “B”

Schedule “C”

APPENDIX 4

Option to Purchase.

OPTION AGREEMENT

THIS AGREEMENT made as of the * day of *, 2007.

B E T W E E N :

*****

(hereinafter referred to as the "**Grantor**")

OF THE FIRST PART;

- and –

HYDRO ONE NETWORKS INC.

(hereinafter referred to as "**HONI**")

OF THE SECOND PART.

The Grantor hereby grants to HONI an option to purchase an easement (the "**Option**") upon the following terms:

1. **Description of Property**

The lands and premises subject to the Option are the lands described on Schedule "A" (the "**Option Property**").

2. **Purchase Price**

The Option purchase price shall be * ($*) Dollars payable by way of certified cheque on closing, subject to usual adjustments.

3. **Exercise of Option**

The Option may be exercised by HONI any time prior to * and shall be exercised by notice in writing by HONI to the Grantor.

4. **Agreement of Purchase and Sale**

On and upon the date of the exercise of the Option by HONI, the Grantor shall be deemed to have made, and HONI shall be deemed to have accepted, an Offer to Grant an Easement to Hydro One Networks Inc. (the "**Offer to Grant an Easement**") in exactly the form set out in Schedule "A" hereto.

5. **Grantor's Covenants**

Upon the exercise of the Option the Grantor shall execute and deliver at the request of HONI any authorizations that may be required by HONI addressed to any relevant government authority, agency or department (the "**Authority**") allowing the inspection of the Option Property by the Authority and permitting the release by the Authority of any relevant information concerning the Option Property to HONI or its solicitors.

6. **The Planning Act**

The agreement resulting from the exercise of the Option shall be effective to create an interest in the Option Property only if the applicable subdivision control provisions of the *Planning Act*, R.S.O. 1990, as amended, are complied with by the Grantor prior to closing. The Grantor shall forthwith make any application to the local Committee of Adjustment or Land Division Committee for any consent that may be required pursuant to the Planning Act.

7. **Time Of The Essence**

Time shall be of the essence of the Option and the agreement resulting from the exercise thereof.

8. **Closing**

The Transfer of Easement arising from the Offer to Grant an Easement shall be completed on the Closing date set out therein, since the Offer to Grant an Easement becomes a binding contract between the parties when the parties are deemed to have made and accepted the Offer, as of the date of the exercise of the Option.

9. **Enurement**

This agreement and everything herein contained shall operate to the benefit of, and be binding upon, the respective heirs, successors, permitted assigns and other legal representatives, as the case may be, of each of the parties hereto.

10. **Tender**

Any tender of documents or money hereunder may be made upon the Grantor or HONI or upon the solicitor acting for the party on whom tender is desired.

11. **Notices**

Where this agreement requires notice to be delivered by one party to the other, such notice shall be given in writing and delivered either personally, or by pre-paid registered post or by facsimile, by the party wishing to give such notice, or by the solicitor acting for such party, to the other party or to the solicitor acting for the other party at the addresses noted below:

To: Grantor

Facsimile No:
Phone:

Attention:

To: HONI

Hydro One Networks Inc.
Real Estate Services
P.O. Box 4300
Markham, ON
L3R 5Z5

Facsimile No: (416) 345-6242
Phone: (416) 562-9184

Attention:

Such notice shall be deemed to have been given, in the case of personal delivery, on the date of delivery, and, where given by registered post, on the third business day following the posting thereof, and if sent by facsimile, the date of delivery shall be deemed to be the date of transmission if transmission occurs prior to 4:00 p.m. (Toronto time) on a business day and on the business day next following the date of transmission in any other case. It is understood that in the event of a threatened or actual postal disruption in the postal service in the postal area through which such notice must be sent, notice must be given personally as aforesaid or by facsimile, in which case notice shall be deemed to have been given as set out above.

12. **Registration**

This agreement and any right or interest transferred hereby may be registered on title to the Option Property.

13. Should any provision or provisions of this Agreement be declared illegal or unenforceable, it or they shall be considered separate and severable from the Agreement and

its remaining provisions shall remain in force and be binding upon the parties hereto as though the said provision or provisions had never been included.

14. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario.

15. Unless otherwise defined herein, all capitalized terms herein shall have the meaning ascribed to them in the Offer to Grant an Easement.

IN WITNESS WHEREOF the Parties have hereunto set their respective hands and seals to this Agreement of Purchase and Sale.

SIGNED, SEALED AND DELIVERED		
In the presence of	)	
	)	______________________
(seal)	)	Grantor
	)	
	)	
	)	
SIGNED, SEALED AND DELIVERED	)	Consent Signature & Release of
In the presence of	)	Grantor's Spouse, if non-owner.
	)	
	)	______________________
(seal)		

HYDRO ONE NETWORKS INC.

Per: ______________________

Title: ______________________

I have authority to bind the Corporation

APPENDIX 5

Damage Claim Form

THIS MEMORANDUM OF AGREEMENT dated the day of 2007

Between: herein called the “Claimant”

- and-

Hydro One Networks Inc.

Witnesseth:

The Claimant agrees to accept ……………………………………………………………….

($) in full payment and satisfaction of all claims or demands for damages of whatsoever kind, nature or extent which may have been done to date by Hydro during the construction, completion, operation or maintenance of the works of Hydro constructed on Lot(s) ………………………………….. , Concession(s) ………………………………...or according to Registered Plan No. …………………in the ………………………………………………… of ……………………………………………of which property the Claimant is the …………………………………and which damages may be approximately summarized and itemized as :

Subject to Approval by Hydro One Networks Inc.

Witness

____
Signature

____
Signature

____
Address

W.O. ___________________________

APPENDIX 6

Damage Release Form

FULL AND FINAL RELEASE

IN CONSIDERATION of the payment or of the promise of payment to the undersigned of the aggregate sum of [Insert settlement amount]($), the receipt and sufficiency of which is hereby acknowledged, I/We, the undersigned, on behalf of myself/ourselves, my/our heirs, executors, administrators, successors and assigns (hereinafter the "Releasors"), hereby release and forever discharge HYDRO ONE NETWORKS INC., its officers, directors, employees, servants and agents and its parent, affiliates, subsidiaries, successors and assigns (hereinafter the "Releasees") from any and all actions, causes of action, claims and demands of every kind including damages, costs, interest and loss or injury of every nature and kind, howsoever arising, which the Releasors now have, may have had or may hereafter have arising from or in any way related to the destruction and/or removal of
[Insert description of the damage caused] on the Releasors' property situated at [Insert legal description], Ontario in or about the [Insert timeline when damage occurred], and specifically including all damages, loss and injury not now known or anticipated but which may arise or develop in the future, including all of the effects and consequences thereof.

AND FOR THE SAID CONSIDERATION, the Releasors further agree not to make any claim or take any proceedings against any other person or corporation who might claim contribution or indemnity under the provisions of the *Negligence Act* and the amendments thereto from the persons or corporations discharged by this release.

AND FOR THE SAID CONSIDERATION, the Releasors further agree not to disclose, publish or communicate by any means, directly or indirectly, the terms, conditions and details of this settlement to or with any persons other than immediate family and legal counsel.

AND THE RELEASORS hereby confirm and acknowledge that the Releasors have sought or declined to seek independent legal advice before signing this Release, that the terms of this

Release are fully understood, and that the said amounts and benefits are being accepted voluntarily, and not under duress, and in full and final compromise, adjustment and settlement of all claims against the Releasees.

IT IS UNDERSTOOD AND AGREED that the said payment or promise of payment is deemed to be no admission whatsoever of liability on the part of the Releasees.

AND IT IS UNDERSTOOD AND AGREED that this Release may be executed in separate counterparts (and may be transmitted by facsimile) each of which shall be deemed to be an original and that such counterparts shall together constitute one and the same instrument, notwithstanding the date of actual execution.

IN WITNESS WHEREOF, the Releasors have hereunto set their respective hands this .... day of ...., 200 .

SIGNED, SEAL AND DELIVERED in the presence of	)	
______________________________ Witness	)	______________________________
______________________________ Address	)	

SIGNED, SEAL AND DELIVERED in the presence of	)	
______________________________ Witness	)	______________________________
______________________________ Address	)	

APPENDIX 7

Testing and Associated Access Routes.

THIS AGREEMENT made as of this __________ day of ______________, 2007.

B E T W E E N:

HYDRO ONE NETWORKS INC.

(hereinafter called "HONI")
OF THE FIRST PART

-and-

(hereinafter called the "Owner")
OF THE SECOND PART

WHEREAS:

1. The Owner is the registered owner of the lands legally described as

(the "Lands").

2. HONI desires to enter onto the Lands to perform certain tests, inspections, studies, and surveys (collectively, the "Tests") on the Lands; and, to construct and utilize access routes ("Access Routes") that may be required to conduct such Tests on the Lands, in connection with its "Bruce to Milton Transmission Reinforcement Project" (the "Project").

3. The Owner is agreeable to allowing HONI to enter onto the Lands for these purposes, subject to the terms and conditions contained herein.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the sum of Two Dollars ($2.00) now paid by each party to the other and the respective covenants and agreements of the parties hereinafter contained (the receipt and sufficiency of which are hereby acknowledged by the parties hereto), the parties hereto agree as follows:

1. The Owner hereby grants to HONI: a) the right to enter upon the Lands, as of the date hereof, for the purpose of conducting such Tests as HONI, in its sole discretion and acting reasonably, deems necessary to determine the suitability of the Lands for the Project; and, b) the right to enter upon the Lands to construct and utilize Access Routes necessary to conduct such Tests.

2. HONI agrees that it shall take all reasonable care in the conduct of the Tests, and that it shall : a) compensate the Owner for any crop damage to the Lands caused by the Tests and/or Access Routes; b) restore the Lands to its prior condition so far as possible and

practicable following such Tests; c) compensate the Owner for any land compaction relief required to reinstate the Lands' soil to its original condition, to the extent possible and practicable; and, d) place within the Access Routes area any necessary drainage works to maintain any required water flows.

3. All agents, representatives, officers, directors, employees and contractors and any property of HONI located at any time on the Lands shall be at the sole risk of HONI and the Owner shall not be liable for any loss or damage or injury (including loss of life) to them or it however occurring except and to the extent to which such loss, damage or injury is caused by the negligence or wilful misconduct of the Owner.

4. HONI agrees that it shall indemnify and save harmless the Owner from and against all claims, demands, costs, damages, expenses and liabilities (collectively the "Costs") whatsoever arising out of HONI's presence on the Lands or of its activities on or in connection with the Lands arising out of the permission granted herein except to the extent any of such Costs arise out of or are contributed to by the negligence or willful misconduct of the Owner.

5. This Agreement and the permission granted herein shall automatically terminate upon the completion by HONI of the Tests and the removal of the Access Routes.

6. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable herein. The parties hereto submit themselves to the exclusive jurisdiction of the Courts of the Province of Ontario.

7. Any amendments, modification or supplement to this Agreement or any part thereof shall not be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of this Agreement.

8. This Agreement and everything herein contained shall operate to the benefit of, and be binding upon, the respective heirs, successors, permitted assigns and other legal representatives, as the case may be, of each of the Parties hereto.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper officers duly authorized in that behalf.

OWNER

SIGNED
IN THE PRESENCE OF :

Per:______________________________________
Print Name: __________________________

HYDRO ONE NETWORKS INC.

Per:______________________________________
Print Name: __________________________
Print Title: ___________________________

I have authority to bind the corporation.

APPENDIX 8

Off-Corridor Temporary Access and Access Roads.

73207 rev. 7-73
Temporary Access and Temporary Access Road

THIS INDENTURE made in duplicate the ________ day of ______________________ 2007

Between:

[Insert name of Owner].
(hereinafter referred to as the "Grantor")
OF THE FIRST PART

--- and ---

HYDRO ONE NETWORKS INC.
(hereinafter referred to "HONI")
OF THE SECOND PART

WHEREAS the Grantor is the owner in fee simple and in possession of [Customize by inserting correct legal description], which land is referred to herein as the "Lands";

WHEREAS HONI desires the right to enter on the Lands in order to obtain access to its electrical transmission lines and other works associated with its "Bruce to Milton Transmission Reinforcement Project" (the "Project")

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the payment of [Insert consideration] by HONI to the Grantor, and the mutual covenants herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. The Grantor hereby grants, conveys and transfers to HONI in, over, along, and upon that part of the Lands as shown in Schedule "A" attached hereto, (the "Access Lands") the rights privileges, and easements, for the servants, agents, contractors and workmen of HONI at all times with all necessary vehicles and equipment: a) to pass and repass over the Access Lands for the purpose of access to its electrical transmission lines and other works in the area during the construction associated with the Project, subject to payment of compensation for damages to any crops or lanes caused thereby; b) to construct, use and maintain upon the Access Lands a temporary road, with such gates, bridges and drainage works as may be necessary for HONI's purposes (collectively, the "Works"), all of which Works shall be removed by HONI upon completion of the construction associated with the Project.; and, c) to cut and remove all trees, brush and other obstructions made necessary by the exercise of the rights granted hereunder

2. HONI. shall remedy any physical damage to the Access Lands and / or property that results from HONI's use of the Access Lands; and, shall restore the Access Lands to its prior condition so far as possible and practicable following the construction.

3. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Access Lands shall be at the sole risk of HONI and the Grantor shall not be liable for any loss or damage or injury (including loss of life) to them or it however occurring except and to the extent to which such loss, damage or injury is caused by the negligence or willful misconduct of the Grantor.

4.HONI agrees that it shall indemnify and save harmless the Grantor from and against all claims, demands, costs, damages, expenses and liabilities (collectively the "Costs") whatsoever arising out of HONI's presence on the Access Lands or of its activities on or in connection with the Access Lands arising out of the permission granted herein except to the extent any of such Costs arise out of or are contributed to by the negligence or willful misconduct of the Grantor.

5. This Agreement and the permission granted herein shall automatically terminate upon the completion by HONI of the construction of the Project and the removal of the Works.

6. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable herein. The parties hereto submit themselves to the exclusive jurisdiction of the Courts of the Province of Ontario.

7. Any amendments, modification or supplement to this Agreement or any part thereof shall not be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of this Agreement.

8. This Agreement and everything herein contained shall operate to the benefit of, and be binding upon, the respective heirs, successors, permitted assigns and other legal representatives, as the case may be, of each of the Parties hereto.

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the day and year first above written.

Signed in the presence of:

____
Grantor

____
Grantor

____
Address

____

____
Phone

Signed in the presence of:

____
Hydro One Networks Inc.

____
I have authority to bind the Corporation

File ________________

<u>SCHEDULE “A”</u>

PROPERTY SKETCH

LAND MAPS